| THIS FILING IS | | |
|---|---|---|
| Item 1: [X] An Initial (Original) Submission | OR [ ] | Resubmission No. ____ |

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2019)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2019)
Form 3-Q Approved
OMB No.1902-0205
(Expires 12/31/2019)

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

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

| **Exact Legal Name of Respondent (Company)** | **Year/Period of Report** |
|---|---|
| Portland General Electric Company | **End of** 2017/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: http://www.ferc.gov/docs-filing/forms/form-1/elec-subm-soft.asp. 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.)

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

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

"In connection with our regular examination of the financial statements of _____ 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 http://www.ferc.gov/help/how-to.asp.

(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 http://www.ferc.gov/docs-filing/forms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/forms.asp#3Q-gas .

**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 field..."

**General Penalties**

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

# FERC FORM NO. 1/3-Q:
# REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

## IDENTIFICATION

| | |
|---|---|
| 01 Exact Legal Name of Respondent<br>Portland General Electric Company | 02 Year/Period of Report<br>End of 2017/Q4 |
| 03 Previous Name and Date of Change *(if name changed during year)*<br>/ / | |
| 04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)*<br>121 SW Salmon Street, Portland, Oregon 97204 | |
| 05 Name of Contact Person<br>Jardon Jaramillo | 06 Title of Contact Person<br>Controller & Asst. Treasurer |
| 07 Address of Contact Person *(Street, City, State, Zip Code)*<br>121 SW Salmon Street, Portland, Oregon 97204 | |

| 08 Telephone of Contact Person, *Including Area Code* | 09 This Report Is | 10 Date of Report *(Mo, Da, Yr)* |
|---|---|---|
| (503) 464-7051 | (1) [X] An Original (2) [ ] A Resubmission | / / |

## ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

| 01 Name | 03 Signature | 04 Date Signed *(Mo, Da, Yr)* |
|---|---|---|
| James F. Lobdell | James F. Lobdell | 04/06/2018 |
| 02 Title<br>SVP 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.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## LIST OF SCHEDULES (Electric Utility)

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

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

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 | None |
| 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 | None |
| 66 | Generating Plant Statistics Pages | 410-411 | |

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".



Stockholders' Reports Check appropriate box:

[X] Two copies will be submitted

[ ] No annual report to stockholders is prepared

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## GENERAL INFORMATION

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

Jardon Jaramillo
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) [X] No

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent 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 beneficiearies for whom trust was maintained, and purpose of the trust.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## CORPORATIONS CONTROLLED BY RESPONDENT

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

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

| Line No. | Name of Company Controlled (a) | Kind of Business (b) | Percent Voting Stock Owned (c) | Footnote Ref. (d) |
|---|---|---|---|---|
| 1 | 121 SW Salmon Street Corporation | Company has leased the | 100 | |
| 2 | | headquarters complex in | | |
| 3 | | Portland, Oregon and sub- | | |
| 4 | | leases the complex to | | |
| 5 | | Respondent. | | |
| 6 | | | | |
| 7 | World Trade Center Northwest Corporation | Company is the holder of the | 100 | |
| 8 | (A wholly-owned subsidiary of 121 SW Salmon | World Trade Center Franchise | | |
| 9 | Street Corporation) | | | |
| 10 | | | | |
| 11 | Salmon Springs Hospitality Group | Company provides food | 100 | |
| 12 | | catering services. | | |
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| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## OFFICERS

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

| Line No. | Title (a) | Name of Officer (b) | Salary for Year (c) |
|---|---|---|---|
| 1 | President and Chief Executive Officer | James J. Piro | 819,288 |
| 2 | President and Chief Executive Officer | Maria M. Pope | 503,575 |
| 3 | Senior Vice President of Finance, Chief Financial | James F. Lobdell | 430,850 |
| 4 | Officer and Treasurer | | |
| 5 | Senior Vice President, Customer Service | William O. Nicholson | 328,272 |
| 6 | Transmission and Distribution | | |
| 7 | Vice President, General Counsel and Corporate | J. Jeffery Dudley | 190,474 |
| 8 | Compliance Officer | | |
| 9 | Vice President, Public Policy and | W. David Robertson | 309,449 |
| 10 | Corporate Resiliency | | |
| 11 | Vice President, Customer Strategies and Business | Carol A. Dillin | 297,493 |
| 12 | Development | | |
| 13 | Vice President, Transmission and Distribution | Larry N. Bekkedahl | 297,493 |
| 14 | Vice President, Information Technology and Chief | Campbell A. Henderson | 271,902 |
| 15 | Information Officer | | |
| 16 | Vice President, Generation and Power Operations | Bradley Y. Jenkins | 280,037 |
| 17 | Vice President, Customer Service Operations | Kristin A. Stathis | 255,435 |
| 18 | Vice President, Human Resources, Diversity | Anne E. Mersereau | 244,786 |
| 19 | and Inclusion | | |
| 20 | Vice President, General Counsel and Corporate | Lisa A. Kaner | 179,342 |
| 21 | Compliance Officer | | |
| 22 | | | |
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***Schedule Page: 104 Line No.: 1 Column: b***

Retired from company effective December 31, 2017.

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

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

***Schedule Page: 104 Line No.: 2 Column: b***

Appointed as President effective October 1, 2017 and appointed as Chief Executive Officer effective January 1, 2018.

***Schedule Page: 104 Line No.: 7 Column: b***

Retired from the company effective August 1, 2017

***Schedule Page: 104 Line No.: 14 Column: b***

Retired from the company effective January 2, 2018

***Schedule Page: 104 Line No.: 20 Column: b***

Appointed to position effective June 29, 2017

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), 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 | Private Investor, Retired from First Chicago NBD Corp. | |
| 3 | Rodney L. Brown, Jr. | Seattle, Washington |
| 4 | Managing Partner, Cascadia Law Group PLLC | |
| 5 | Jack E. Davis | Scottsdale, Arizona |
| 6 | Chair of the Board of Portland General Electric Company | |
| 7 | Retired Chief Executive Officer of | |
| 8 | Arizona Public Service Company | |
| 9 | David A. Dietzler | Lake Oswego, Oregon |
| 10 | Retired Partner of KPMG LLP | |
| 11 | Kirby A. Dyess | Beaverton, Oregon |
| 12 | Principal, Austin Capital Management LLC | |
| 13 | Mark B. Ganz | Portland, Oregon |
| 14 | President and Chief Executive Officer of | |
| 15 | Cambia Health Solutions | |
| 16 | Kathryn J. Jackson | Pittsburgh, Pennsylvania |
| 17 | Director, Energy & Technology Consulting with KeySource | |
| 18 | Neil J. Nelson | Portland, Oregon |
| 19 | President and Chief Executive Officer of Siltronic Corp. | |
| 20 | M. Lee Pelton | Boston, Massachusetts |
| 21 | President of Emerson College | |
| 22 | James J. Piro | Portland, Oregon |
| 23 | President and Chief Executive Officer of | |
| 24 | Portland General Electric Company | |
| 25 | Charles W. Shivery | Longboat Key, Florida |
| 26 | Retired Chairman of Northeast Utilities | |
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***Schedule Page: 105 Line No.: 22 Column: a***

Retired from position effective December 31, 2017

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

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

Does the respondent have formula rates?

[ ] Yes
[X] 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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| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## 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
[X] 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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| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## 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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| 1 | | | | |
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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.

1. None

2. None

3. None

4. None

5. None

6. Pursuant to PGE's application, the FERC, on January 3, 2018, issued an order in Docket No. ES17-59-000 that authorizes the Company to issue up to $900 million of short-term debt through February 6, 2020. 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, 2017, PGE had a $500 million revolving credit facility scheduled to expire in November 2021.

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 for general corporate purposes, 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 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. PGE 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, 2017, since PGE had no borrowings outstanding, and no commercial paper or letters of credit issued, 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 can request letters of credit for original terms not to exceed one year. These facilities provide for a total capacity of $220 million. The issuance of such letters of credit is subject to the approval of the issuing institution. Under these four facilities, $67 million of letters of credit were outstanding, as of December 31, 2017.

On August 2, 2017, PGE and certain institutional buyers (Buyers) in the private placement market entered into a Bond Purchase Agreement (Agreement) under which PGE would sell to the Buyers an aggregate principal amount of $225 million of PGE's First Mortgage Bonds (Bonds) in two tranches. Both series of Bonds will bear interest from their issue date at an annual rate of 3.98%. The Public Utility Commission of Oregon (OPUC) authorized the Company to issue up to $500 million of Bonds and Debt Securities under Order 16-152, dated April 21, 2017. The first tranche, $75 million with a maturity in 2048, was issued in August 2017. The second tranche, $150 million with a maturity in 2047, was issued in November 2017.

In May 2016, PGE entered into an unsecured credit agreement with certain financial institutions under which PGE obtained three separate loans totaling $150 million. The Company repaid the loans in the amount of:

- $50 million on August 21, 2017;
- $25 million on October 30, 2017; and
- $75 million on November 27, 2017.

The term loan interest rates were set at the beginning of the interest period for periods of one, three, or six months, as selected by PGE, and were based on the London Interbank Offered Rate plus 63 basis points. The final rate was 1.87% as of November 27, 2017, with no other fees.

PGE enters into financial agreements and power and natural gas purchase and sale agreements 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, 2017, 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***

**<u>Dreyer, Gearhart and Kafoury Bros., LLC v. Portland General Electric Company</u>, Marion County Circuit Court; and <u>Morgan v. Portland General Electric Company</u>, Marion County Circuit Court.**

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 legal proceedings, lawsuits were filed against PGE on behalf of two classes of electric service customers: Dreyer, Gearhart and Kafoury Bros., LLC v. Portland General Electric Company, Marion County Circuit Court; and 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 August 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 of $33 million, including interest, which were completed in 2010. Following appeals, the 2008 Order was upheld by the Oregon Court of Appeals in February 2013 and by the OSC in October 2014.

In June 2015, based on a motion filed by PGE, the Marion County Circuit Court (Circuit Court) lifted the abatement and in July 2015, the Circuit Court heard oral argument on the Company's motion for Summary Judgment. In March 2016, the Circuit Court entered a general judgment that granted the Company's motion for Summary Judgment and dismissed all claims by the plaintiffs. On April 14, 2016, the plaintiffs appealed the Circuit Court dismissal to the Court of Appeals for the State of Oregon. Briefing on the appeal is now complete, with a Court of Appeals decision pending.

PGE believes that the October 2, 2014 OSC decision and the recent Circuit Court decisions have reduced the risk of a loss to the Company in excess of the amounts previously recorded and discussed above. However, because the class actions remain subject to a decision in the appeal, management believes that it is reasonably possible that such a loss to the Company could result. As these matters involve unsettled legal theories and have a broad range of potential outcomes, sufficient information is currently not available to determine the amount of any such loss.

***Carty***

**<u>In the Matter of an Arbitration Under the Rules of the International Chamber of Commerce's Court of Arbitration</u>, International Chamber of Commerce's Court of Arbitration.**

**<u>Portland General Electric Company v. Liberty Mutual Insurance Company and Zurich American Insurance Company</u>, U.S. District Court of the District of Oregon.**

**<u>Portland General Electric Company v. Abeinsa EPC LLC, Abener Construction Services, LLC (formerly known as Abener Engineering and Construction Services, LLC), Teyma Construction USA LLC, and Abeinsa Abener Teyma General Partnership,</u> U.S. District Court of the District of Oregon.**

In 2013, PGE entered into a turnkey engineering, procurement, and construction agreement (Construction Agreement) with Abeinsa EPC LLC, Abener Construction Services, LLC, Teyma Construction USA, LLC, and Abeinsa Abener Teyma General Partnership (collectively, the "Contractor"), affiliates of Abengoa S.A. - for the construction of the Carty natural gas-fired generating plant (Carty) located in Eastern Oregon. Liberty Mutual Insurance Company and Zurich American Insurance Company (together, the "Sureties") provided a performance bond of $145.6 million (Performance Bond) in connection with the Construction Agreement.

In December 2015, the Company declared the Contractor in default under the Construction Agreement and terminated the Construction Agreement. Following termination of the Construction Agreement, PGE brought on new contractors and construction resumed.

Carty was placed into service on July 29, 2016 and the Company began collecting its revenue requirement in customer prices on August 1, 2016, as authorized by the OPUC, based on the approved capital cost of $514 million. Actual costs for the construction of Carty exceeded the approved amount and, as of December 31, 2017, PGE has capitalized $637 million to Utility Plant.

As the final construction cost exceeded the amount authorized by the OPUC, higher interest and depreciation expense than allowed in the Company's revenue requirement has resulted. These incremental expenses are recognized in the Company's current results of operations, as a deferral for such amounts would not be considered probable of recovery at this time, in accordance with GAAP.

As actual project costs for Carty have exceeded $514 million, the Company has incurred a higher cost of service than what is reflected in the current authorized revenue requirement amount, primarily due to higher depreciation, interest expense and legal expenses. Such incremental expenses were $14 million and $3 million for the year ended December 31, 2017 and 2016, respectively. Any amounts approved by the OPUC for recovery under the deferral filing would be recognized in earnings in the period of such approval.

Actual costs do not reflect any offsetting amounts that may be received from the Sureties, pursuant to the Performance Bond. The amounts recorded also exclude $8 million of liens and claims filed for goods and services provided under contracts with the former Contractor that remain in dispute. The Company believes these liens and claims are invalid and is contesting the liens and claims in the courts.

The incremental costs resulted from various matters relating to the resumption of construction activities following the termination of the Construction Agreement, including, among other things, completing the remaining construction work, correcting deficiencies and defects in work performed by the former Contractor, determining the remaining scope of construction, preparing work plans for contractors, identifying new contractors, negotiating contracts, and procuring additional materials.

Other items contributing to the increase include costs relating to the removal of certain liens filed on the property for goods and services provided under contracts with the former Contractor, and costs to repair equipment damage that resulted from poor storage and maintenance on the part of the former Contractor.

In July 2016, the Company requested from the OPUC a regulatory deferral for the recovery of the revenue requirement associated with the incremental capital costs for Carty starting from its in service date to the date that such amounts are approved in a subsequent regulatory proceeding. The Company has requested that the OPUC delay its review of this deferral request until all legal actions with respect to this matter, including PGE's actions against the Sureties, have been resolved.

Any amounts approved by the OPUC for recovery under the deferral filing would be recognized in earnings in the period of such approval, however there is no assurance that such recovery would be granted by the OPUC. The Company believes that costs incurred to date and capitalized in Utility Plant, in the Comparative Balance Sheet, were prudently incurred. There have been no settlement discussions with regulators related to such costs.

The Company is involved in several litigation proceedings concerning the termination of the Construction Agreement and the payment obligations of the Sureties.

PGE is seeking recovery of incremental construction costs and other damages pursuant to breach of contract claims against the Contractor and claims against the Sureties pursuant to the Performance Bond. The Sureties have denied liability in whole under the Performance Bond.

Various actions relating to this matter have been filed in the U.S. District Court for the District of Oregon (U.S. District Court), in the Ninth Circuit Court of Appeals (Ninth Circuit), and in an arbitration proceeding, including the following:

- A breach of contract claim dated March 23, 2016, Portland General Electric Company v. Liberty Mutual Insurance Company and Zurich American Insurance Company, U.S. District Court of the District of Oregon, brought by PGE against the Sureties in U.S. District Court asserting that the Sureties are responsible for the payment of all damages sustained by PGE as a result of the Contractor’s breach of contract. The Company’s complaint disputes the Sureties’ assertion that the Company wrongfully terminated the Construction Agreement and asserts that the Sureties are responsible for the payment of all damages sustained by PGE as a result of the Sureties’ breach of contract, including damages in excess of the $145.6 million stated amount of the Performance Bond. Such damages include additional costs incurred by PGE to complete Carty.

- A claim dated October 21, 2016, Portland General Electric Company v. Abeinsa EPC LLC, Abener Construction Services, LLC (formerly known as Abener Engineering and Construction Services, LLC), Teyma Construction USA LLC, and Abeinsa Abener Teyma General Partnership, U.S. District Court of the District of Oregon, brought by PGE in U.S. District Court against the Contractor for failure to satisfy its obligations under the Construction Agreement. PGE is seeking damages from the Contractor in excess of $200 million for: i) costs incurred to complete construction of Carty, settle claims with unpaid contractors and vendors, and remove liens; and ii) damages in excess of the construction costs, including a project management fee, liquidated damages under the Construction Agreement, legal fees and costs, damages due to delay of the project, warranty costs, and interest.

- A claim dated December 31, 2015, In the Matter of an Arbitration Under the Rules of the International Chamber of Commerce’s Court of Arbitration, International Chamber of Commerce’s Court of Arbitration, by Abengoa S.A. in the ICC arbitration proceeding alleging that the Company’s termination of the Construction Agreement was wrongful and in breach of the terms of the agreement and did not give rise to any liability of Abengoa S.A.; and

- A claim by the Contractor against PGE in the ICC arbitration proceeding seeking damages of $117 million based on a claim that PGE wrongfully terminated the Construction Agreement and $44 million based on a claim that PGE failed to disclose certain information to the Contractor, in connection with the Contractor’s bid submitted pursuant to the Company’s request for proposals.

Following various procedural arguments in the ICC arbitration and the U.S. District Court, in July 2017, the Ninth Circuit held that the ICC arbitral tribunal had jurisdiction to determine what parties and what claims could be presented in the ICC arbitration as opposed to in court. A hearing before the ICC arbitral tribunal is expected to take place on April 9 and 10, 2018. The decision of the ICC arbitral tribunal is expected to determine the forum in which the above referenced claims will be heard.

After exhausting all remedies against the aforementioned parties, the Company intends to seek approval to recover any remaining excess amounts in customer prices in a subsequent regulatory proceeding. However, there is no assurance that such recovery would be allowed by the OPUC.

In accordance with GAAP and the Company's accounting policies, any such excess costs may be charged to expense at the time disallowance of recovery becomes probable and a reasonable estimate of the amount of such disallowance can be made. As of the date of this report, the Company has concluded that the likelihood is less than probable that a portion of the cost of Carty will be disallowed for recovery in customer prices. Accordingly, no loss has been recorded to date related to the project.

***Deschutes River Alliance Clean Water Act Claims***

**Deschutes River Alliance v. Portland General Electric Company, U.S. District Court of the District of Oregon.**

On August 12, 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, which seeks injunctive and declaratory relief against PGE under the Clean Water Act (CWA) related to alleged past and continuing violations of the CWA. Specifically, DRA claims PGE has 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 alleges 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, 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 Deschutes River's fish and wildlife habitat below the Project and harmed the economic and personal interests of DRA's members and supporters.

In September 2016, PGE filed a motion to dismiss, which asserted that the CWA does not allow citizen suits of this nature, and that the FERC has jurisdiction over all licensing issues, including the alleged CWA violations. On March 27, 2017, the court denied PGE's motion to dismiss. On April 6, 2017, PGE filed a motion with the District Court for certification to file an interlocutory appeal with the Ninth Circuit and for a stay of the District Court proceeding. The District Court granted PGE's request on May 19, 2017, but the Ninth Circuit denied the appeal on August 14, 2017. On April 7, 2017, the District Court granted an unopposed motion filed by the Confederated Tribes of Warm Springs (the Tribes) to appear in the case as a friend of the court. The Tribes share ownership of the Project with PGE, but have not been named as a defendant.

Following conferences and negotiations involving various parties, and with the expiration of the stay, the District Court Judge, on January 17, 2018, established a briefing schedule for summary judgment motions.

The Company cannot predict the outcome of this matter, but believes that it has strong defenses to DRA's claims and intends to defend against them. Because i) this matter involves novel issues of law and ii) the mechanism and costs for achieving the relief sought in DRA's claims have not yet been determined, the Company cannot, at this time, determine the likelihood of whether the outcome of this matter will result in a material loss.

10. None

11. (Reserved)

12. None

13. Changes in Officers and Directors:

    J. Jeffrey Dudley, Vice President, General Counsel, Corporate Compliance Officer and Assistant Secretary of PGE retired effective July 1, 2017.

    Lisa A. Kaner was appointed Vice President, General Counsel, and Corporate Compliance Officer effective June 29, 2017.

James J. Piro, President and Chief Executive Officer (CEO), notified the Board of Directors on July 26, 2017 of his decision to retire from PGE on December 31, 2017. The Board of Directors appointed Maria M. Pope, Senior Vice President of Power Supply, Operations and Resource Strategy, to succeed Mr. Piro.

Mr. Piro also retired as a member of the Board of Directors effective December 31, 2017.

On October 1, 2017, Ms. Pope assumed the role of Company President and, effective January 1, 2018, the role of CEO and member of the Board of Directors.

14. None

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

| Line No. | Title of Account (a) | Ref. Page No. (b) | Current Year End of Quarter/Year Balance (c) | Prior Year End Balance 12/31 (d) |
|---|---|---|---|---|
| 1 | **UTILITY PLANT** | | | |
| 2 | Utility Plant (101-106, 114) | 200-201 | 10,081,537,481 | 9,701,607,393 |
| 3 | Construction Work in Progress (107) | 200-201 | 390,550,304 | 212,574,352 |
| 4 | TOTAL Utility Plant (Enter Total of lines 2 and 3) | | 10,472,087,785 | 9,914,181,745 |
| 5 | (Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115) | 200-201 | 4,663,342,841 | 4,367,096,860 |
| 6 | Net Utility Plant (Enter Total of line 4 less 5) | | 5,808,744,944 | 5,547,084,885 |
| 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) | | 5,808,744,944 | 5,547,084,885 |
| 15 | Utility Plant Adjustments (116) | | 0 | 0 |
| 16 | Gas Stored Underground - Noncurrent (117) | | 0 | 0 |
| 17 | **OTHER PROPERTY AND INVESTMENTS** | | | |
| 18 | Nonutility Property (121) | | 48,510,868 | 45,528,825 |
| 19 | (Less) Accum. Prov. for Depr. and Amort. (122) | | 16,088,583 | 15,872,239 |
| 20 | Investments in Associated Companies (123) | | 0 | 0 |
| 21 | Investment in Subsidiary Companies (123.1) | 224-225 | 143,936 | 225,325 |
| 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 | 4,155 |
| 25 | Sinking Funds (125) | | 0 | 0 |
| 26 | Depreciation Fund (126) | | 0 | 0 |
| 27 | Amortization Fund - Federal (127) | | 0 | 0 |
| 28 | Other Special Funds (128) | | 83,172,108 | 79,029,625 |
| 29 | Special Funds (Non Major Only) (129) | | 0 | 0 |
| 30 | Long-Term Portion of Derivative Assets (175) | | 297,009 | 4,932,477 |
| 31 | Long-Term Portion of Derivative Assets – Hedges (176) | | 0 | 0 |
| 32 | TOTAL Other Property and Investments (Lines 18-21 and 23-31) | | 116,035,338 | 113,848,168 |
| 33 | **CURRENT AND ACCRUED ASSETS** | | | |
| 34 | Cash and Working Funds (Non-major Only) (130) | | 0 | 0 |
| 35 | Cash (131) | | 8,913,582 | 4,705,005 |
| 36 | Special Deposits (132-134) | | 11,418,874 | 7,742,604 |
| 37 | Working Fund (135) | | 22,200 | 22,200 |
| 38 | Temporary Cash Investments (136) | | 30,000,000 | 1,000,000 |
| 39 | Notes Receivable (141) | | 0 | 0 |
| 40 | Customer Accounts Receivable (142) | | 135,645,919 | 130,689,416 |
| 41 | Other Accounts Receivable (143) | | 38,342,848 | 30,676,525 |
| 42 | (Less) Accum. Prov. for Uncollectible Acct.-Credit (144) | | 6,344,122 | 6,391,021 |
| 43 | Notes Receivable from Associated Companies (145) | | 0 | 0 |
| 44 | Accounts Receivable from Assoc. Companies (146) | | 66,656 | 11,631 |
| 45 | Fuel Stock (151) | 227 | 24,167,931 | 29,885,835 |
| 46 | Fuel Stock Expenses Undistributed (152) | 227 | 0 | 2,656,990 |
| 47 | Residuals (Elec) and Extracted Products (153) | 227 | 0 | 0 |
| 48 | Plant Materials and Operating Supplies (154) | 227 | 48,363,416 | 43,215,761 |
| 49 | Merchandise (155) | 227 | 0 | 0 |
| 50 | Other Materials and Supplies (156) | 227 | 490 | 0 |
| 51 | Nuclear Materials Held for Sale (157) | 202-203/227 | 0 | 0 |
| 52 | Allowances (158.1 and 158.2) | 228-229 | 2,331,408 | 1,967,963 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## 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 | 3,988,473 | 4,320,139 |
| 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) | | 56,069,078 | 52,868,533 |
| 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) | | 105,509,836 | 107,297,016 |
| 62 | Miscellaneous Current and Accrued Assets (174) | | 0 | -2,481 |
| 63 | Derivative Instrument Assets (175) | | 5,966,435 | 23,330,838 |
| 64 | (Less) Long-Term Portion of Derivative Instrument Assets (175) | | 297,009 | 4,932,477 |
| 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) | | 464,166,015 | 429,064,477 |
| 68 | **DEFERRED DEBITS** | | | |
| 69 | Unamortized Debt Expenses (181) | | 9,948,581 | 11,078,032 |
| 70 | Extraordinary Property Losses (182.1) | 230a | 0 | 0 |
| 71 | Unrecovered Plant and Regulatory Study Costs (182.2) | 230b | 1,698,256 | 520,947 |
| 72 | Other Regulatory Assets (182.3) | 232 | 535,236,011 | 513,975,906 |
| 73 | Prelim. Survey and Investigation Charges (Electric) (183) | | 2,172,803 | 2,586,289 |
| 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) | | 211,312 | -47,341 |
| 77 | Temporary Facilities (185) | | 4,597 | 0 |
| 78 | Miscellaneous Deferred Debits (186) | 233 | 14,082,050 | 14,037,620 |
| 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) | | 18,937,291 | 22,306,993 |
| 82 | Accumulated Deferred Income Taxes (190) | 234 | 606,727,109 | 357,636,563 |
| 83 | Unrecovered Purchased Gas Costs (191) | | 0 | 0 |
| 84 | Total Deferred Debits (lines 69 through 83) | | 1,189,018,010 | 922,095,009 |
| 85 | TOTAL ASSETS (lines 14-16, 32, 67, and 84) | | 7,577,964,307 | 7,012,092,539 |

| Name of Respondent | This Report is: | Date of Report (mo, da, yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [x] An Original<br>(2) [ ] A Resubmission | / / | end of 2017/Q4 |

## COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

| Line No. | Title of Account (a) | Ref. Page No. (b) | Current Year End of Quarter/Year Balance (c) | Prior Year End Balance 12/31 (d) |
|---|---|---|---|---|
| 1 | PROPRIETARY CAPITAL | | | |
| 2 | Common Stock Issued (201) | 250-251 | 1,210,926,574 | 1,205,506,206 |
| 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 | 1,217,326,912 | 1,150,098,955 |
| 12 | Unappropriated Undistributed Subsidiary Earnings (216.1) | 118-119 | 132,936 | 214,325 |
| 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) | -7,906,742 | -7,664,109 |
| 16 | Total Proprietary Capital (lines 2 through 15) | | 2,416,204,985 | 2,343,880,682 |
| 17 | LONG-TERM DEBT | | | |
| 18 | Bonds (221) | 256-257 | 2,436,400,000 | 2,211,400,000 |
| 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 | 71,868 | 150,077,857 |
| 22 | Unamortized Premium on Long-Term Debt (225) | | 0 | 0 |
| 23 | (Less) Unamortized Discount on Long-Term Debt-Debit (226) | | 540,975 | 598,395 |
| 24 | Total Long-Term Debt (lines 18 through 23) | | 2,435,930,893 | 2,360,879,462 |
| 25 | OTHER NONCURRENT LIABILITIES | | | |
| 26 | Obligations Under Capital Leases - Noncurrent (227) | | 48,648,132 | 51,220,862 |
| 27 | Accumulated Provision for Property Insurance (228.1) | | 0 | 0 |
| 28 | Accumulated Provision for Injuries and Damages (228.2) | | 8,867,943 | 8,883,992 |
| 29 | Accumulated Provision for Pensions and Benefits (228.3) | | 399,235,308 | 393,771,443 |
| 30 | Accumulated Miscellaneous Operating Provisions (228.4) | | 0 | 0 |
| 31 | Accumulated Provision for Rate Refunds (229) | | 1,981,970 | 670,584 |
| 32 | Long-Term Portion of Derivative Instrument Liabilities | | 150,869,575 | 125,236,136 |
| 33 | Long-Term Portion of Derivative Instrument Liabilities - Hedges | | 0 | 0 |
| 34 | Asset Retirement Obligations (230) | | 166,978,691 | 161,101,224 |
| 35 | Total Other Noncurrent Liabilities (lines 26 through 34) | | 776,581,619 | 740,884,241 |
| 36 | CURRENT AND ACCRUED LIABILITIES | | | |
| 37 | Notes Payable (231) | | 0 | 0 |
| 38 | Accounts Payable (232) | | 228,100,970 | 227,364,147 |
| 39 | Notes Payable to Associated Companies (233) | | 0 | 0 |
| 40 | Accounts Payable to Associated Companies (234) | | 179,005 | 337,639 |
| 41 | Customer Deposits (235) | | 13,544,300 | 16,176,504 |
| 42 | Taxes Accrued (236) | 262-263 | 13,866,867 | 12,632,394 |
| 43 | Interest Accrued (237) | | 26,780,919 | 24,925,797 |
| 44 | Dividends Declared (238) | | 31,445,355 | 29,600,824 |
| 45 | Matured Long-Term Debt (239) | | 0 | 0 |

| Name of Respondent | This Report is: | Date of Report (mo, da, yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | end of 2017/Q4 |

## COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(continued)

| Line No. | Title of Account<br>(a) | Ref. Page No.<br>(b) | Current Year End of Quarter/Year Balance<br>(c) | Prior Year End Balance 12/31<br>(d) |
|---|---|---|---|---|
| 46 | Matured Interest (240) | | 0 | 0 |
| 47 | Tax Collections Payable (241) | | 16,775,837 | 12,222,118 |
| 48 | Miscellaneous Current and Accrued Liabilities (242) | | 21,451,375 | 32,580,354 |
| 49 | Obligations Under Capital Leases-Current (243) | | 2,572,730 | 2,661,556 |
| 50 | Derivative Instrument Liabilities (244) | | 209,422,871 | 169,624,416 |
| 51 | (Less) Long-Term Portion of Derivative Instrument Liabilities | | 150,869,575 | 125,236,136 |
| 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) | | 413,270,654 | 402,889,613 |
| 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 | 124,641,511 | 38,706,904 |
| 60 | Other Regulatory Liabilities (254) | 278 | 428,336,695 | 98,334,688 |
| 61 | Unamortized Gain on Reaquired Debt (257) | | 42,273 | 50,325 |
| 62 | Accum. Deferred Income Taxes-Accel. Amort.(281) | 272-277 | 0 | 0 |
| 63 | Accum. Deferred Income Taxes-Other Property (282) | | 820,571,329 | 790,256,094 |
| 64 | Accum. Deferred Income Taxes-Other (283) | | 162,384,347 | 236,210,530 |
| 65 | Total Deferred Credits (lines 56 through 64) | | 1,535,976,155 | 1,163,558,541 |
| 66 | TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65) | | 7,577,964,306 | 7,012,092,539 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## STATEMENT OF INCOME

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

Annual or Quarterly if applicable
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 columnin 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 | 2,022,693,552 | 1,939,166,814 | | |
| 3 | Operating Expenses | | | | | |
| 4 | Operation Expenses (401) | 320-323 | 1,014,564,000 | 1,020,207,505 | | |
| 5 | Maintenance Expenses (402) | 320-323 | 161,260,902 | 144,242,966 | | |
| 6 | Depreciation Expense (403) | 336-337 | 290,673,780 | 266,415,570 | | |
| 7 | Depreciation Expense for Asset Retirement Costs (403.1) | 336-337 | 6,891,509 | 7,087,268 | | |
| 8 | Amort. & Depl. of Utility Plant (404-405) | 336-337 | 46,134,140 | 44,097,840 | | |
| 9 | Amort. of Utility Plant Acq. Adj. (406) | 336-337 | | | | |
| 10 | Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407) | | -15,481,862 | -12,840,314 | | |
| 11 | Amort. of Conversion Expenses (407) | | | | | |
| 12 | Regulatory Debits (407.3) | | 12,971,720 | 13,760,743 | | |
| 13 | (Less) Regulatory Credits (407.4) | | 2,109,466 | 2,761,244 | | |
| 14 | Taxes Other Than Income Taxes (408.1) | 262-263 | 121,629,678 | 117,893,057 | | |
| 15 | Income Taxes - Federal (409.1) | 262-263 | 5,389,048 | 11,475,291 | | |
| 16 | - Other (409.1) | 262-263 | 12,084,686 | 3,247,837 | | |
| 17 | Provision for Deferred Income Taxes (410.1) | 234, 272-277 | 506,077,684 | 240,078,412 | | |
| 18 | (Less) Provision for Deferred Income Taxes-Cr. (411.1) | 234, 272-277 | 438,525,396 | 202,432,150 | | |
| 19 | Investment Tax Credit Adj. - Net (411.4) | 266 | | | | |
| 20 | (Less) Gains from Disp. of Utility Plant (411.6) | | | | | |
| 21 | Losses from Disp. of Utility Plant (411.7) | | | -35,338 | | |
| 22 | (Less) Gains from Disposition of Allowances (411.8) | | | | | |
| 23 | Losses from Disposition of Allowances (411.9) | | | | | |
| 24 | Accretion Expense (411.10) | | 3,662,308 | 3,259,304 | | |
| 25 | TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24) | | 1,725,222,731 | 1,653,696,747 | | |
| 26 | Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27 | | 297,470,821 | 285,470,067 | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

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 | | |
|---|---|---|---|---|---|---|
| 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) | Line No. |
| | | | | | | 1 |
| 2,022,693,552 | 1,939,166,814 | | | | | 2 |
| | | | | | | 3 |
| 1,014,564,000 | 1,020,207,505 | | | | | 4 |
| 161,260,902 | 144,242,966 | | | | | 5 |
| 290,673,780 | 266,415,570 | | | | | 6 |
| 6,891,509 | 7,087,268 | | | | | 7 |
| 46,134,140 | 44,097,840 | | | | | 8 |
| | | | | | | 9 |
| -15,481,862 | -12,840,314 | | | | | 10 |
| | | | | | | 11 |
| 12,971,720 | 13,760,743 | | | | | 12 |
| 2,109,466 | 2,761,244 | | | | | 13 |
| 121,629,678 | 117,893,057 | | | | | 14 |
| 5,389,048 | 11,475,291 | | | | | 15 |
| 12,084,686 | 3,247,837 | | | | | 16 |
| 506,077,684 | 240,078,412 | | | | | 17 |
| 438,525,396 | 202,432,150 | | | | | 18 |
| | | | | | | 19 |
| | | | | | | 20 |
| | -35,338 | | | | | 21 |
| | | | | | | 22 |
| | | | | | | 23 |
| 3,662,308 | 3,259,304 | | | | | 24 |
| 1,725,222,731 | 1,653,696,747 | | | | | 25 |
| 297,470,821 | 285,470,067 | | | | | 26 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

STATEMENT OF INCOME FOR THE YEAR (continued)

| Line No. | Title of Account (a) | (Ref.) Page No. (b) | TOTAL Current Year (c) | TOTAL Previous Year (d) | Current 3 Months Ended Quarterly Only No 4th Quarter (e) | Prior 3 Months Ended Quarterly Only No 4th Quarter (f) |
|---|---|---|---|---|---|---|
| 27 | Net Utility Operating Income (Carried forward from page 114) | | 297,470,821 | 285,470,067 | | |
| 28 | Other Income and Deductions | | | | | |
| 29 | Other Income | | | | | |
| 30 | Nonutilty Operating Income | | | | | |
| 31 | Revenues From Merchandising, Jobbing and Contract Work (415) | | | | | |
| 32 | (Less) Costs and Exp. of Merchandising, Job. & Contract Work (416) | | | | | |
| 33 | Revenues From Nonutility Operations (417) | | 2,718,347 | 2,827,339 | | |
| 34 | (Less) Expenses of Nonutility Operations (417.1) | | 3,151,752 | 2,690,302 | | |
| 35 | Nonoperating Rental Income (418) | | 2,998,518 | 2,576,880 | | |
| 36 | Equity in Earnings of Subsidiary Companies (418.1) | 119 | -81,389 | 59,882 | | |
| 37 | Interest and Dividend Income (419) | | 335,336 | 214,373 | | |
| 38 | Allowance for Other Funds Used During Construction (419.1) | | 11,726,094 | 20,604,316 | | |
| 39 | Miscellaneous Nonoperating Income (421) | | 1,287,467 | -327,195 | | |
| 40 | Gain on Disposition of Property (421.1) | | | | | |
| 41 | TOTAL Other Income (Enter Total of lines 31 thru 40) | | 15,832,621 | 23,265,293 | | |
| 42 | Other Income Deductions | | | | | |
| 43 | Loss on Disposition of Property (421.2) | | | | | |
| 44 | Miscellaneous Amortization (425) | | 20,322 | | | |
| 45 | Donations (426.1) | | 1,871,065 | 1,886,981 | | |
| 46 | Life Insurance (426.2) | | -2,751,122 | -566,291 | | |
| 47 | Penalties (426.3) | | 37,888 | 295 | | |
| 48 | Exp. for Certain Civic, Political & Related Activities (426.4) | | 996,431 | 1,036,435 | | |
| 49 | Other Deductions (426.5) | | 4,217,367 | 2,763,277 | | |
| 50 | TOTAL Other Income Deductions (Total of lines 43 thru 49) | | 4,391,951 | 5,120,697 | | |
| 51 | Taxes Applic. to Other Income and Deductions | | | | | |
| 52 | Taxes Other Than Income Taxes (408.2) | 262-263 | 1,146,107 | 1,395,973 | | |
| 53 | Income Taxes-Federal (409.2) | 262-263 | -1,176,868 | -683,007 | | |
| 54 | Income Taxes-Other (409.2) | 262-263 | -277,143 | -160,732 | | |
| 55 | Provision for Deferred Inc. Taxes (410.2) | 234, 272-277 | 6,026,612 | 268,228 | | |
| 56 | (Less) Provision for Deferred Income Taxes-Cr. (411.2) | 234, 272-277 | 3,576,299 | 1,483,114 | | |
| 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) | | 2,142,409 | -662,652 | | |
| 60 | Net Other Income and Deductions (Total of lines 41, 50, 59) | | 9,298,261 | 18,807,248 | | |
| 61 | Interest Charges | | | | | |
| 62 | Interest on Long-Term Debt (427) | | 117,516,111 | 114,599,147 | | |
| 63 | Amort. of Debt Disc. and Expense (428) | | 1,042,671 | 1,028,897 | | |
| 64 | Amortization of Loss on Reaquired Debt (428.1) | | 3,369,702 | 2,570,544 | | |
| 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) | | 3,716,817 | 4,168,461 | | |
| 69 | (Less) Allowance for Borrowed Funds Used During Construction-Cr. (432) | | 6,000,616 | 10,819,605 | | |
| 70 | Net Interest Charges (Total of lines 62 thru 69) | | 119,636,633 | 111,539,392 | | |
| 71 | Income Before Extraordinary Items (Total of lines 27, 60 and 70) | | 187,132,449 | 192,737,923 | | |
| 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) | | 187,132,449 | 192,737,923 | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## 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 | | 1,146,246,160 | 1,066,194,363 |
| 2 | Changes | | | |
| 3 | Adjustments to Retained Earnings (Account 439) | | | |
| 4 | | | | |
| 5 | | | | |
| 6 | | | | |
| 7 | | | | |
| 8 | | | | |
| 9 | TOTAL Credits to Retained Earnings (Acct. 439) | | | |
| 10 | | | | |
| 11 | | | | |
| 12 | | | | |
| 13 | | | | |
| 14 | | | | |
| 15 | TOTAL Debits to Retained Earnings (Acct. 439) | | | |
| 16 | Balance Transferred from Income (Account 433 less Account 418.1) | | 187,213,838 | 192,678,041 |
| 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 | | | -119,985,881 | ( 112,625,770) |
| 32 | | | | |
| 33 | | | | |
| 34 | | | | |
| 35 | | | | |
| 36 | TOTAL Dividends Declared-Common Stock (Acct. 438) | | -119,985,881 | ( 112,625,770) |
| 37 | Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings | | | ( 474) |
| 38 | Balance - End of Period (Total 1,9,15,16,22,29,36,37) | | 1,213,474,117 | 1,146,246,160 |
| | APPROPRIATED RETAINED EARNINGS (Account 215) | | | |
| 39 | | | | |
| 40 | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## 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) | | 3,852,795 | 3,852,795 |
| 47 | TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46) | | 3,852,795 | 3,852,795 |
| 48 | TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1) | | 1,217,326,912 | 1,150,098,955 |
| | UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account | | | |
| | Report only on an Annual Basis, no Quarterly | | | |
| 49 | Balance-Beginning of Year (Debit or Credit) | | 214,325 | 153,969 |
| 50 | Equity in Earnings for Year (Credit) (Account 418.1) | | -81,389 | 59,882 |
| 51 | (Less) Dividends Received (Debit) | | | |
| 52 | | | | 474 |
| 53 | Balance-End of Year (Total lines 49 thru 52) | | 132,936 | 214,325 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## STATEMENT OF CASH FLOWS

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

| Line No. | Description (See Instruction No. 1 for Explanation of Codes)<br>(a) | Current Year to Date Quarter/Year<br>(b) | Previous Year to Date Quarter/Year<br>(c) |
|---|---|---|---|
| 1 | Net Cash Flow from Operating Activities: | | |
| 2 | Net Income (Line 78(c) on page 117) | 187,132,449 | 192,737,923 |
| 3 | Noncash Charges (Credits) to Income: | | |
| 4 | Depreciation and Depletion | 343,699,429 | 317,600,678 |
| 5 | Amortization of Debt Discount | 4,404,321 | 3,591,389 |
| 6 | Amortization of Unrecovered Plant | -15,481,862 | -12,840,314 |
| 7 | Price Risk Managment | 57,162,858 | -133,714,713 |
| 8 | Deferred Income Taxes (Net) | 70,002,601 | 36,431,376 |
| 9 | Investment Tax Credit Adjustment (Net) | | |
| 10 | Net (Increase) Decrease in Receivables | -10,937,570 | -10,006,935 |
| 11 | Net (Increase) Decrease in Inventory | 3,194,970 | 792,482 |
| 12 | Net (Increase) Decrease in Allowances Inventory | | |
| 13 | Net Increase (Decrease) in Payables and Accrued Expenses | 2,182,425 | 14,356,015 |
| 14 | Net (Increase) Decrease in Other Regulatory Assets | -95,530,224 | 147,641,220 |
| 15 | Net Increase (Decrease) in Other Regulatory Liabilities | 46,811,742 | -24,453,292 |
| 16 | (Less) Allowance for Other Funds Used During Construction | 11,726,094 | 20,604,316 |
| 17 | (Less) Undistributed Earnings from Subsidiary Companies | -81,389 | 59,882 |
| 18 | Margin Deposits | -6,308,474 | 26,451,881 |
| 19 | Other | 17,987,352 | 10,867,591 |
| 20 | | | |
| 21 | | | |
| 22 | Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21) | 592,675,312 | 548,791,103 |
| 23 | | | |
| 24 | Cash Flows from Investment Activities: | | |
| 25 | Construction and Acquisition of Plant (including land): | | |
| 26 | Gross Additions to Utility Plant (less nuclear fuel) | -521,932,854 | -603,153,901 |
| 27 | Gross Additions to Nuclear Fuel | | |
| 28 | Gross Additions to Common Utility Plant | | |
| 29 | Gross Additions to Nonutility Plant | -4,106,903 | -4,994,352 |
| 30 | (Less) Allowance for Other Funds Used During Construction | -11,726,094 | -20,604,316 |
| 31 | Other Capital Activities | 2,042,892 | 1,411,779 |
| 32 | | | |
| 33 | | | |
| 34 | Cash Outflows for Plant (Total of lines 26 thru 33) | -512,270,771 | -586,132,158 |
| 35 | | | |
| 36 | Acquisition of Other Noncurrent Assets (d) | | |
| 37 | Proceeds from Disposal of Noncurrent Assets (d) | | |
| 38 | | | |
| 39 | Investments in and Advances to Assoc. and Subsidiary Companies | | 2,414,511 |
| 40 | Contributions and Advances from Assoc. and Subsidiary Companies | | |
| 41 | Disposition of Investments in (and Advances to) | | |
| 42 | Associated and Subsidiary Companies | | |
| 43 | Sales Tax Refund | | 90,888 |
| 44 | Purchase of Investment Securities (a) | | |
| 45 | Proceeds from Sales of Investment Securities (a) | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## STATEMENT OF CASH FLOWS

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

| Line No. | Description (See Instruction No. 1 for Explanation of Codes)<br>(a) | Current Year to Date Quarter/Year<br>(b) | Previous Year to Date Quarter/Year<br>(c) |
|---|---|---|---|
| 46 | Loans Made or Purchased | | |
| 47 | Collections on Loans | | |
| 48 | Other Investments | -3,413,222 | -2,574,742 |
| 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 | -17,690,262 | -24,723,652 |
| 54 | Sales of Trojan Decommissioning Securities | 20,708,931 | 26,681,261 |
| 55 | | | |
| 56 | Net Cash Provided by (Used in) Investing Activities | | |
| 57 | Total of lines 34 thru 55) | -512,665,324 | -584,243,892 |
| 58 | | | |
| 59 | Cash Flows from Financing Activities: | | |
| 60 | Proceeds from Issuance of: | | |
| 61 | Long-Term Debt (b) | 225,000,000 | 290,000,000 |
| 62 | Preferred Stock | | |
| 63 | Common Stock | -3,335,911 | -2,546,583 |
| 64 | Other (provide details in footnote): | | |
| 65 | | | |
| 66 | Net Increase in Short-Term Debt (c) | | |
| 67 | Other (provide details in footnote): | | |
| 68 | | | |
| 69 | | | |
| 70 | Cash Provided by Outside Sources (Total 61 thru 69) | 221,664,089 | 287,453,417 |
| 71 | | | |
| 72 | Payments for Retirement of: | | |
| 73 | Long-term Debt (b) | -150,005,989 | -133,005,992 |
| 74 | Preferred Stock | | |
| 75 | Common Stock | | |
| 76 | Other (provide details in footnote): | | |
| 77 | Debt Issue Costs | -949,780 | -601,849 |
| 78 | Net Decrease in Short-Term Debt (c) | | -5,999,500 |
| 79 | | | |
| 80 | Dividends on Preferred Stock | | |
| 81 | Dividends on Common Stock | -117,509,731 | -110,192,494 |
| 82 | Net Cash Provided by (Used in) Financing Activities | | |
| 83 | (Total of lines 70 thru 81) | -46,801,411 | 37,653,582 |
| 84 | | | |
| 85 | Net Increase (Decrease) in Cash and Cash Equivalents | | |
| 86 | (Total of lines 22,57 and 83) | 33,208,577 | 2,200,793 |
| 87 | | | |
| 88 | Cash and Cash Equivalents at Beginning of Period | 5,727,205 | 3,526,412 |
| 89 | | | |
| 90 | Cash and Cash Equivalents at End of period | 38,935,782 | 5,727,205 |

NOTES TO FINANCIAL STATEMENTS

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

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

**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 Year |
|---|---|---|
| Cash (131) | $ 4,705,005 | $ 8,913,582 |
| Working Funds (135) | 22,200 | 22,200 |
| Temporary Cash Investments (136) | 1,000,000 | 30,000,000 |
| | $ 5,727,205 | $ 38,935,782 |
| | | |
| | **2016** | **2017** |
| Cash paid during the year: | | |
| Interest | $ 114,362,752 | $ 115,688,306 |
| Allowance for borrowed funds used during construction | (10,819,605) | (6,000,616) |
| | $ 103,543,147 | $ 109,687,690 |
| | | |
| Income Taxes | $ 15,502,009 | $ 18,268,023 |
| | | |
| Non-cash investing and financing activities: | | |
| Accrued capital additions | $ 49,990,942 | $ 53,364,382 |
| Accrued dividends payable | 29,600,824 | 31,445,355 |
| Assets obtained under leasing arrangements | 77,991,864 | 86,417,558 |
| Preliminary engineering transferred to Construction work in progress | 348,144 | 266,487 |

**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 4,000 square mile, state-approved service area is located entirely within the State of Oregon. PGE's allocated service area includes 51 incorporated cities, of which Portland and Salem are the largest. As of December 31, 2017, PGE served approximately 875,000 retail customers with a service area population of approximately 1.9 million, comprising approximately 46% of the population of the state.

As of December 31, 2017, PGE had 2,906 employees, with 785 employees covered under one of two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 732 and 53 employees and expire March 2020 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, and accumulated asset retirement removal costs.

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 - Price 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.

***Subsequent events***

PGE has evaluated the impact of events occurring after December 31, 2017 up to February 16, 2017, the date that the Company's U.S. GAAP financial statements were issued, and has updated such evaluation for disclosure purposes through April 6, 2018. These financial statements include all necessary adjustments and disclosures resulting from such evaluations.

**NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES**

***Cash and Cash Equivalents***

Highly liquid investments with maturities of three months or less at the date of acquisition are classified as Temporary Cash Investments cash equivalents, of which PGE had $30 million as of December 31, 2017 and $1 million as of December 31, 2016.

***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 16 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.

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 are based on management's assessment of the probability of collection, aging of Customer Accounts Receivable, bad debt write-offs, actual customer billings, and other factors.

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 accounts receivable related to wholesale sales in 2017 or 2016.

***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. 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 power costs for the Company's retail customers.

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.

Pursuant to transactions entered into in connection with PGE's price risk management activities, the Company may be required to provide collateral with 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 Other current assets in the Comparative Balance Sheet and were $11 million and $8 million as of December 31, 2017 and 2016, respectively. Letters of credit provided as collateral are not recorded on the Company's Comparative Balance Sheet and were $31 million and $17 million as of December 31, 2017 and 2016, 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 it is 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 (CWIP) 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. AFDC is capitalized as part of the cost of plant and credited to the Statement of Income. The average rate used by PGE was 7.3% in 2017 and 2016. AFDC from borrowed funds was $6 million in 2017 and $11 million in 2016 and is reflected as a reduction to Interest Charges. AFDC from equity funds, included in Other Income, was $12 million in 2017 and $21 million in 2016.

*Depreciation and Amortization*

Depreciation is computed using the straight-line method, based upon original cost, and includes an estimate for cost of removal and expected salvage. Depreciation Expense as a percent of the related average depreciable plant in service was 3.6% in 2017, 3.5% in 2016 and 3.6% in 2015. 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. The most recent depreciation study was completed for 2015, 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 estimated retirement dates, which range from 2020 to 2059. Depreciation is provided on PGE's other classes of plant in service over their estimated average service lives, which are as follows (in years):

| | |
|---|---|
| Generation, excluding thermal: | |
| Hydro | 95 |
| Wind | 30 |
| Transmission | 57 |
| Distribution | 45 |
| General | 12 |

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 depreciation.

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 $296 million and $257 million as of December 31, 2017 and 2016, respectively, with amortization expense of $46 million in 2017 and $44 million in 2016. Future estimated amortization expense as of December 31, 2017 is as follows: $49 million in 2018; $48 million in 2019; $43 million in 2020; $35 million in 2021; and $28 million in 2022.

***Marketable Securities***

All of PGE's investments in marketable securities, included in the Non-qualified benefit plan trust and Nuclear decommissioning trust on the Comparative Balance Sheet, are classified as trading. These securities are classified as noncurrent because they are not available for use in operations. Trading securities are stated at fair value based on quoted market prices. Realized and unrealized gains and losses on the Non-qualified benefit plan trust assets are included in Miscellaneous Nonoperating Income. Realized and unrealized gains and losses on the Nuclear decommissioning trust fund assets are recorded as Other Regulatory Liabilities or Assets, respectively, for future ratemaking treatment. The cost of securities sold is based on the average cost method.

***Regulatory Accounting***

*Regulatory Assets and Liabilities*

As a rate-regulated enterprise, PGE applies regulatory accounting, which results in the creation of regulatory assets and regulatory liabilities. Regulatory assets represent: i) probable future revenue associated with certain actual or estimated costs that are expected to be recovered from customers through the ratemaking process; or ii) probable future collections from customers resulting from revenue accrued for completed alternative revenue programs, provided certain criteria are met. Regulatory liabilities represent probable future reductions in revenue associated with amounts that are expected to be credited to customers through the ratemaking process. Regulatory accounting is appropriate as long as: prices are established by, or subject to, approval by independent third-party regulators; prices are designed to recover the specific enterprise's cost of service; and in view of demand for service, it is reasonable to assume that prices set at levels that will recover costs can be charged to and collected from customers. 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, the Company can adjust future customer prices to reflect a portion of the difference between net variable power costs (NVPC) forecast each year and included in customer prices (baseline NVPC) and actual NVPC. 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 9.6% for 2017 and 2016, and 9.68% for 2015.

Any estimated refund to customers pursuant to the PCAM is recorded as a reduction in Operating Revenues in PGE's Statement of Income, while any estimated collection from customers is recorded as a reduction in Purchased Power. 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 because quoted market prices and market-risk premiums are not available. The present value of estimated future decommissioning costs is capitalized and included in Utility Plant on the Comparative Balance Sheet with a corresponding offset to ARO. Such estimates are revised periodically, with actual expenditures charged to the ARO as incurred.

The estimated capitalized costs of AROs are depreciated over the estimated life of the related asset, which is 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 Depreciation Expense for Asset Retirement Costs 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. PGE had a regulatory liability related to AROs in the amount of $52 million as of December 31, 2017 and $49 million as of December 31, 2016. For additional information concerning the Company's regulatory liability 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 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.

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.

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

***Accumulated Other Comprehensive Loss***

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

***Revenue Recognition***

Revenues are recognized as electricity is delivered to customers and include amounts for any services provided. Franchise taxes, which are collected from customers and remitted to taxing authorities, are recorded on a gross basis in PGE's Statement of Income. Amounts collected from customers are included in Operating Revenues and amounts due to taxing authorities are included in Taxes other than income taxes and totaled $43 million in 2017 and 2016.

Retail revenue is billed monthly based on meter readings taken throughout the month. Unbilled revenue represents the revenue earned from the time of the last meter read date through the last day of the month, a period that has not been billed as of the last day of the month. Unbilled revenue 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 retail customer prices.

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

***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.

Because PGE is a rate-regulated enterprise, changes in certain deferred tax assets and liabilities are required to be passed on to customers through future prices and are charged or credited directly to a regulatory asset or regulatory liability. Such amounts were recognized as net regulatory liabilities of $277 million and net regulatory assets of $89 million as of December 31, 2017, and 2016, respectively, and will be included in prices when the temporary differences reverse.

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

***Recent Accounting Pronouncements***

Accounting Standards Update (ASU) 2014-09, *Revenue from Contracts with Customers* (Topic 606) (ASU 2014-09), creates a new Topic 606 and supersedes the revenue recognition requirements in Topic 605, *Revenue Recognition*, and most industry-specific guidance throughout the Industry Topics of the Codification. ASU 2014-09 provides a five-step analysis of transactions to determine when and how revenue is recognized that consists of: i) identify the contract with the customer; ii) identify the performance obligations in the contract; iii) determine the transaction price; iv) allocate the transaction price to the performance obligations; and v) recognize revenue when or as each performance obligation is satisfied. Companies can transition to the requirements of this ASU either retrospectively (full retrospective method) or as a cumulative-effect adjustment as of the effective date (modified retrospective method), which is January 1, 2018 for calendar year-end public entities. The Company plans to elect the modified retrospective method for implementation. PGE does not anticipate any material changes to its revenue recognition policy for tariff-based revenues, which comprises a majority of PGE's retail, wholesale, and other revenues, as performance obligations are expected to be satisfied in a similar recognition pattern. PGE continues to finalize its evaluation of certain matters of presentation such as alternative revenue programs (including decoupling) and enhanced required disclosures.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)* which supersedes the current lease accounting requirements for lessees and lessors within Topic 840, *Leases*. Pursuant to the new standard, lessees will be required to recognize all leases, including operating leases, on the Comparative Balance Sheet and record corresponding right-of-use assets and lease liabilities. Accounting for lessors is substantially unchanged from current accounting principles. Lessees will be required to classify leases as either finance leases or operating leases. Initial Comparative Balance Sheet measurement is similar for both types of leases; however, expense recognition and amortization of right-of-use assets will differ. Operating leases will reflect lease expense on a straight-line basis, while finance leases will result in the separate presentation of Interest Charges on the lease liability (as calculated using the effective interest method) and amortization expense of the right-of-use asset. Quantitative and qualitative disclosures will also be required surrounding significant judgments made by management. The provisions of this pronouncement are effective for calendar year-end, public entities on January 1, 2019. As issued, ASU 2016-02 requires transition under a modified retrospective basis as of the beginning of the earliest comparative period presented, however the Company is monitoring the FASB's decisions regarding potential transition practical expedients that would allow companies to adopt the new standard with a cumulative effect adjustment as of the beginning of the year of adoption with prior year comparative financial information and disclosures remaining as previously reported. Early adoption is permitted, but the Company does not plan to early adopt. In January 2018, the FASB issued ASU 2018-01, *Leases (Topic 842) Land Easement Practical Expedient for Transition to Topic 842*, which amends ASU 2016-02 to provide entities an optional transition practical expedient to not evaluate under Topic 842 existing or expired land easements that were not previously accounted for as leases under the current leases guidance in Topic 842. An entity that elects this practical expedient should evaluate new or modified land easements under Topic 842 beginning at the date that the entity adopts Topic 842. PGE plans to elect this practical expedient. The Company is monitoring utility industry implementation issues that may change existing and future lease classification in areas such as purchase power agreements, pipeline laterals, utility pole attachments, and other utility industry-related arrangements. In conjunction with monitoring industry issues that may impact lease classification, the Company is in the process of evaluating whether it will elect to adopt certain other, optional practical expedients included within the standard. Decisions surrounding the election of practical expedients may impact the Company's lease population that is ultimately recorded. As a result, PGE has not yet quantified the estimated financial statement impact, but overall, the Company does expect an increase in the recognition of right-of-use assets and lease liabilities on the Company's Comparative Balance Sheet.

In March 2017, the FASB issued ASU 2017-07, *Compensation-Retirement Benefits (Topic 715), Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost* (ASU 2017-07). Pursuant to this ASU, only the service cost component of net periodic pension and postretirement benefit costs will be eligible for capitalization and should be applied on a prospective basis upon implementation. Also, the non-service components are required to be presented in the income statement separately from the service cost component and outside the subtotal of income from operations and should be applied on a retrospective basis upon implementation. For calendar year-end public entities, the update will be effective for annual periods beginning January 1, 2018. The Company does not plan to early adopt. For ratemaking purposes, the Company will continue to be allowed to recover this portion of the non-service costs as a component of rate base, however such amounts will be recorded as Regulatory assets on the Company's Comparative Balance Sheet, instead of Utility plant, and amortized in a systematic and rational manner and reflected as expense in a line item outside the subtotal of income from operations on the Statement of Income and other comprehensive income. PGE estimates the portion of the non-service components of net periodic pension and postretirement benefit costs that is eligible for deferral for ratemaking purposes, to be $3 million for the twelve month period ending December 31, 2018, and is deemed to have an immaterial impact on the Company's financial position and results of operations.

**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, | |
|---|---|---|
| | 2017 | 2016 |
| Balance as of beginning of year | $ 6 | $ 6 |
| Increase in provision | 6 | 5 |
| Amounts written off, less recoveries | (6) | (5) |
| Balance as of end of year | $ 6 | $ 6 |

***Trust Accounts***

PGE maintains the following trust accounts, both of which are included in Other Special Funds in the Comparative Balance Sheet:

*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 Trojan nuclear power plant (Trojan), which was closed in 1993. The Nuclear decommissioning trust includes amounts collected from customers less qualified expenditures plus any realized and unrealized gains and losses on the investments held therein. In 2014 and 2013, the Company received $6 million and $44 million, respectively, from the settlement of a legal matter concerning costs associated with the operation of the ISFSI. Those funds were deposited into the Nuclear decommissioning trust. For additional information concerning the legal matter, see Note 7, Asset Retirement Obligations. In anticipation of the refund of the settlement amount to customers over a three-year period that began in 2015, those funds were withdrawn from the Nuclear decommissioning trust during 2015.

*Non-qualified benefit plan trust*—Reflects assets held in trust to cover the obligations of PGE's non-qualified benefit plans and represents contributions made by the Company less qualified expenditures plus any realized and unrealized gains and losses on the investment held therein.

The trusts are comprised of the following investments as of December 31 (in millions):

| | Nuclear Decommissioning Trust | | Non-Qualified Benefit Plan Trust | |
|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 |
| Cash equivalents | $ 25 | $ 21 | $ 1 | $ 1 |
| Marketable securities, at fair value: | | | | |
| Equity securities | — | — | 7 | 6 |
| Debt securities | 17 | 20 | 1 | 1 |
| Insurance contracts, at cash surrender value | — | — | 28 | 26 |
| | $ 42 | $ 41 | $ 37 | $ 34 |

For information concerning the fair value measurement of those assets recorded at fair value held in the trusts, see Note 4, Fair Value of Financial Instruments.

**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, 2017 and 2016, and then classifies these financial assets and liabilities based on a fair value hierarchy that is used to prioritize the inputs to the valuation techniques used to measure fair value. The three levels 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 which 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, 2017 and 2016, 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, 2017 | | | | |
| --- | --- | --- | --- | --- | --- |
| | Level 1 | Level 2 | Level 3 | Other(2) | Total |
| Assets: | | | | | |
| Nuclear decommissioning trust: (1) | | | | | |
| Debt securities: | | | | | |
| Domestic government | $ 4 | $ 7 | $ — | $ — | $ 11 |
| Corporate credit | — | 6 | — | — | 6 |
| Money market funds measured at NAV (2) | — | — | — | 25 | 25 |
| Non-qualified benefit plan trust: (3) | | | | | |
| Money market funds | 1 | — | — | — | 1 |
| Equity securities—domestic | 7 | — | — | — | 7 |
| Debt securities—domestic government | 1 | — | — | — | 1 |
| Investments measured at NAV: (2) | | | | | |
| Collective trust—domestic equity | — | — | — | — | — |
| Assets from price risk management activities: (1) (4) | | | | | |
| Electricity | — | 3 | — | — | 3 |
| Natural gas | — | 3 | — | — | 3 |
| | $ 13 | $ 19 | $ — | $ 25 | $ 57 |
| Liabilities - Liabilities from price risk management activities: (1) (4) | | | | | |
| Electricity | $ — | $ 5 | $ 130 | $ — | $ 135 |
| Natural gas | — | 66 | 9 | — | 75 |
| | $ — | $ 71 | $ 139 | $ — | $ 210 |

(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 $28 million, which are recorded at cash surrender value.
(4) For further information, see Note 5, Price Risk Management.

| | As of December 31, 2016 | | | | |
|---|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Other(2) | Total |
| Assets: | | | | | |
| Nuclear decommissioning trust: (1) | | | | | |
| Debt securities: | | | | | |
| Domestic government | $ 2 | $ 10 | $ — | $ — | $ 12 |
| Corporate credit | — | 8 | — | — | 8 |
| Money market funds measured at NAV (2) | — | — | — | 21 | 21 |
| Non-qualified benefit plan trust: (3) | | | | | |
| Money market funds | 1 | — | — | — | 1 |
| Equity securities—domestic | 4 | — | — | — | 4 |
| Debt securities—domestic government | 1 | — | — | — | 1 |
| Investments measured at NAV: (2) | | | | | |
| Collective trust—domestic equity | — | — | — | 2 | 2 |
| Assets from price risk management activities: (1) (4) | | | | | |
| Electricity | — | 6 | 1 | — | 7 |
| Natural gas | — | 15 | 1 | — | 16 |
| | $ 8 | $ 39 | $ 2 | $ 23 | $ 72 |
| Liabilities - Liabilities from price risk management activities: (1) (4) | | | | | |
| Electricity | $ — | $ 6 | $ 112 | $ — | $ 118 |
| Natural gas | — | 42 | 9 | — | 51 |
| | $ — | $ 48 | $ 121 | $ — | $ 169 |

(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 $26 million, which are recorded at cash surrender value.
(4) For further information, see Note 5, Price Risk Management.

***Assets*** held in the Nuclear decommissioning trust (NDT) and Non-qualified benefit plan (NQBP) trusts are recorded at fair value as Other Special Funds in PGE's Comparative Balance Sheet and invested in securities that are exposed to interest rate, credit, and market volatility risks. These assets are classified within Level 1, 2, or 3 based on the following factors:

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

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

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

*Common and collective trust funds*—PGE invests in common and collective trust funds that invests in equity securities. The Company believes the redemption value of these funds is likely to be the fair value, which is represented by the net asset value as a practical expedient. The funds allow for daily liquidity with appropriate notice. Common and collective trusts are not classified in the fair value hierarchy as they are valued at NAV as a practical expedient. All collective trusts for the NQBP were liquidated during 2017.

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

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

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

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

| Commodity Contracts | Fair Value Assets | Fair Value Liabilities | Valuation Technique | Significant Unobservable Input | Price per Unit Low | Price per Unit High | Price per Unit Weighted Average |
|---|---|---|---|---|---|---|---|
| | (in millions) | | | | | | |
| **As of December 31, 2017:** | | | | | | | |
| Electricity physical forward | $ — | $ 130 | Discounted cash flow | Electricity forward price Electricity (per MWh) | $ 7.79 | $ 41.23 | $ 30.95 |
| Natural gas financial swaps | — | 9 | Discounted cash flow | Natural gas forward price (per Dth) | 1.26 | 2.92 | 1.90 |
| Electricity financial futures | — | — | Discounted cash flow | Electricity forward price (per MWh) | 7.79 | 29.74 | 21.74 |
| | $ — | $ 139 | | | | | |
| **As of December 31, 2016:** | | | | | | | |
| Electricity physical forward | $ — | $ 112 | Discounted cash flow | Electricity forward price (per MWh) | $ 14.25 | $ 54.73 | $ 38.18 |
| Natural gas financial swaps | 1 | 9 | Discounted cash flow | Natural gas forward price (per Dth) | 1.85 | 4.92 | 2.64 |
| Electricity financial futures | 1 | — | Discounted cash flow | Electricity forward price (per MWh) | 8.57 | 33.60 | 25.10 |
| | $ 2 | $ 121 | | | | | |

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

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

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

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

| | Years Ended December 31, 2017 | Years Ended December 31, 2016 |
|---|---|---|
| Net liabilities from price risk management activities as of beginning of year | $ 119 | $ 119 |
| Net realized and unrealized losses * | 35 | 11 |
| Net transfers in to Level 3 from Level 2 | — | (1) |
| Net transfers out of Level 3 to Level 2 | (15) | (10) |
| Net liabilities from price risk management activities as of end of year | $ 139 | $ 119 |
| Level 3 net unrealized losses that have been fully offset by the effect of regulatory accounting | $ 41 | $ 11 |

* Includes $6 million in net realized losses in 2017 and none in 2016.

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 year ended December 31, 2017, there were no transfers into Level 3 from Level 2, as reflected in the table above. During 2016, there was $1 million transferred into Level 3. 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 in and transfers out of Level 3 at the end of the reporting period for all of its derivative instruments. Transfers from Level 2 to Level 1 for the Company's price risk management assets and liabilities do not occur as quoted prices are not available for identical instruments. As such, the Company's assets and liabilities from price risk management activities mature and settle as Level 2 fair value measurements.

***Long-term debt*** is recorded at amortized cost in PGE's Comparative Balance Sheet. The fair value of the Company's First Mortgage Bonds (FMBs) and Pollution Control Revenue Bonds (PCBs) is classified as a Level 2 fair value measurement and is estimated based on the quoted market prices for the same or similar issues or on the current rates offered to PGE for debt of similar remaining maturities. The fair value of PGE's unsecured term bank loans was classified as Level 3 fair value measurement and was estimated based on the terms of the loans and the Company's creditworthiness. The significant unobservable inputs to the Level 3 fair value measurement included the interest rate and the length of the loan. The estimated fair value of the Company's unsecured term bank loans approximated their carrying value.

As of December 31, 2017, the carrying amount of PGE's long-term debt was $2,436 million and its estimated aggregate fair value was $2,829 million, all of which is classified as Level 2 in the fair value hierarchy. As of December 31, 2016, the carrying amount of PGE's long-term debt was $2,361 million with an estimated aggregate fair value of $2,693 million, consisting of $2,543 million and $150 million classified as Level 2 and Level 3, respectively, in the fair value hierarchy.

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

**NOTE 5: PRICE RISK MANAGEMENT**

PGE participates in the wholesale marketplace in order 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 its existing long-term wholesale contracts. Such activities include purchases and sales of both power and fuel resulting from economic dispatch decisions for 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 flow.

PGE utilizes derivative instruments to manage its exposure to commodity price risk and foreign exchange rate risk in order to manage volatility in net variable power costs for its retail customers. Such derivative instruments may include forward, futures, swap, and option contracts, which are recorded at fair value on the Comparative Balance Sheet, for electricity, natural gas, oil, 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 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, 2017 | As of December 31, 2016 |
|---|---|---|
| **Current assets:** | | |
| Commodity contracts: | | |
| Electricity | $ 3 | $ 6 |
| Natural gas | 3 | 12 |
| Total current derivative assets | 6 | 18 |
| **Noncurrent assets:** | | |
| Commodity contracts: | | |
| Electricity | — | 1 |
| Natural gas | — | 4 |
| Total noncurrent derivative assets | — | 5 |
| Total derivative assets not designated as hedging instruments | $ 6 | $ 23 |
| Total derivative assets | $ 6 | $ 23 |
| **Current liabilities:** | | |
| Commodity contracts: | | |
| Electricity | $ 13 | $ 12 |
| Natural gas | 46 | 32 |
| Total current derivative liabilities | 59 | 44 |
| **Noncurrent liabilities:** | | |
| Commodity contracts: | | |
| Electricity | 122 | 106 |
| Natural gas | 29 | 19 |
| Total noncurrent derivative liabilities | 151 | 125 |
| Total derivative liabilities not designated as hedging instruments | $ 210 | $ 169 |
| Total derivative liabilities | $ 210 | $ 169 |

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, 2017 | | As of December 31, 2016 | |
|---|---|---|---|---|
| Commodity contracts: | | | | |
| Electricity | 7 | MWh | 8 | MWh |
| Natural gas | 114 | Dth | 107 | Dth |
| Foreign currency exchange | $ 21 | Canadian | $ 22 | Canadian |

PGE has elected to report gross on the Comparative Balance Sheet the positive and negative exposures resulting from derivative instruments pursuant to agreements that meet the definition of a master netting arrangement. 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, 2017 and 2016, gross amounts included as Derivative Instrument Liabilities subject to master netting agreements were $136 million and $115 million, respectively, for which PGE posted collateral of $11 million for 2017 and 2016, which consisted entirely of letters of credit. As of December 31, 2017, of the gross amounts included, $130 million was for electricity and $6 million was for natural gas compared to $112 million for electricity and $3 million for natural gas recognized as of December 31, 2016.

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, 2017 | 2016 |
|---|---|---|
| Commodity contracts: | | |
| Electricity | $ 41 | $ 34 |
| Natural Gas | 85 | (56) |
| Foreign currency exchange | (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. Net losses of $82 million and net (gains) of $13 million for the years ended December 31, 2017 and 2016, respectively, have been offset in Net Income.

Assuming no changes in market prices and interest rates, the following table presents the year in which the net unrealized loss recorded as of December 31, 2017 related to PGE's derivative activities would be realized as a result of the settlement of the underlying derivative instrument (in millions):

| | 2018 | 2019 | 2020 | 2021 | 2022 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Commodity contracts: | | | | | | | |
| Electricity | $ 10 | $ 8 | $ 8 | $ 8 | $ 7 | $ 91 | $ 132 |
| Natural gas | 43 | 20 | 7 | 2 | — | — | 72 |
| Net unrealized loss | $ 53 | $ 28 | $ 15 | $ 10 | $ 7 | $ 91 | $ 204 |

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 all derivative instruments with credit-risk-related contingent features that were in a liability position as of December 31, 2017 was $205 million, for which the Company had posted $31 million in collateral, consisting entirely of letters of credit. If the credit-risk-related contingent features underlying these agreements were triggered at December 31, 2017, the cash requirement to either post as collateral or settle the instruments immediately would have been $202 million. As of December 31, 2017, PGE had no 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, 2017 | 2016 |
|---|---|---|
| **Assets from price risk management activities:** | | |
| Counterparty A | 39 % | 22 % |
| Counterparty B | 12 | 17 |
| Counterparty C | 3 | 12 |
| | 54 % | 51 % |
| **Liabilities from price risk management activities:** | | |
| Counterparty D | 62 % | 66 % |
| | 62 % | 66 % |

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):

| | Weighted Average Remaining Life (1) | As of December 31, 2017 | 2016 |
|---|---|---|---|
| Regulatory assets: | | | |
| Price risk management (2) | 6 years | $ 203 | $ 146 |
| Pension and other postretirement plans (2) | (3) | 218 | 235 |
| Deferred income taxes (6) | (4) | 56 | 89 |
| Other (5) | Various | 58 | 44 |
| Total regulatory assets | | $ 535 | $ 514 |
| Regulatory liabilities: | | | |
| Deferred income taxes (6) | (4) | 332 | 3 |
| Trojan decommissioning activities | 5 years | 3 | 18 |
| Asset retirement obligations (6) | (4) | 52 | 49 |
| Other | Various | 41 | 28 |
| Total regulatory liabilities | | $ 428 | $ 98 |

(1) As of December 31, 2017.
(2) Does not include a return on investment.
(3) Recovery expected over the average service life of employees.
(4) Recovery or refund expected over the estimated lives of the net balance.
(5) Of the total other unamortized regulatory asset balances, a return is recorded on $51 million and $44 million as of December 31, 2017 and 2016, respectively.
(6) Included in rate base for ratemaking purposes.

As of December 31, 2017, PGE had regulatory assets of $51 million earning a return on investment at the following rates: i) $14 million earning a return by inclusion in rate base; ii) $25 million at the approved rate for deferred accounts under amortization, ranging from 1.47% to 2.38%, depending on the year of approval; iii) $10 million at PGE's 2017 cost of capital of 7.51%, and iv) $2 million at a rate of the 5-year Treasury rate plus 100 basis points, which currently equates to 2.87%.

*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, Price 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 benefit cost. For further information, see Note 10, Employee Benefits.

*Deferred income taxes* represents income tax benefits primarily from property-related timing differences that previously flowed to customers and will be included in customer prices when the temporary differences reverse. In 2017, the net regulatory liability was increased by $357 million as the Company deferred the impact of re-measuring accumulated deferred income taxes pursuant to the enactment of the Tax Cuts and Jobs Act (the TCJA) on December 22, 2017. PGE has proposed to defer and refund the net benefits of the change in tax law under a deferral application filed with the OPUC on December 29, 2017. Substantially all of the amounts deferred under the proposed deferral application 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 would have occurred before the change in tax law. The Company plans to use the average rate assumption method to account for the refund to customers. For further information, see Note 11, Income Taxes.

*Trojan decommissioning activities* represents proceeds received for the settlement of a legal matter concerning the reimbursement from the United States Department of Energy (USDOE) of certain monitoring costs incurred related to spent nuclear fuel at Trojan, as well as ongoing costs and collections associated with decommissioning activities.

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

**NOTE 7: ASSET RETIREMENT OBLIGATIONS**

AROs consist of the following (in millions):

| | As of December 31, | |
| --- | --- | --- |
| | **2017** | **2016** |
| Trojan decommissioning activities | $ 45 | $ 44 |
| Utility plant | 109 | 105 |
| Non-utility property | 13 | 12 |
| Asset retirement obligations | $ 167 | $ 161 |

*Trojan decommissioning activities* represents the present value of future decommissioning costs for the plant, 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 is to house the spent nuclear fuel at the former plant site until an off-site storage facility is available. Decommissioning of the ISFSI and final site restoration activities will begin once shipment of all the spent fuel to a USDOE facility is complete, which is not expected prior to 2034.

In 2004, the co-owners of Trojan (PGE, Eugene Water & Electric Board, and PacifiCorp, collectively referred to as Plaintiffs) filed a complaint against the USDOE for failure to accept spent nuclear fuel by January 31, 1998. PGE, which holds a 67.5% ownership interest in Trojan, had contracted with the USDOE for the permanent disposal of spent nuclear fuel in order to allow the final decommissioning of Trojan. The Plaintiffs paid for permanent disposal services during the period of plant operation and have met all other conditions precedent. The Plaintiffs sought reimbursement for damages incurred through 2009.

A trial before the U.S. Court of Federal Claims concluded in 2012, with the Court issuing a judgment awarding certain damages to the Plaintiffs. The settlement agreement also provides for a process to submit claims for allowable costs for the periods subsequent to 2009, including an extension to cover costs through 2019. Pursuant to this process, the USDOE has reimbursed the Plaintiffs $85 million for costs incurred through 2016 resulting from USDOE delays in accepting spent nuclear fuel.

PGE has received proceeds of $53 million related to its share in this legal matter. The settlement amounts received were recorded as a regulatory liability to offset amounts previously collected in relation to Trojan decommissioning activities. In December 2014, the OPUC issued an order on the Company’s 2015 GRC, authorizing the return of $50 million of the proceeds received related to this legal matter to customers over a three-year period beginning January 1, 2015. PGE will return the remaining $3 million to customers in 2018.

The ARO related to Trojan decommissioning activities was not impacted by the outcome of this legal matter because the proceeds received in connection with the settlement of this legal matter were for past Trojan decommissioning costs and this ARO reflects future Trojan decommissioning costs.

*Utility Plant* represents AROs that have been recognized for the Company’s thermal and wind generation sites, distribution and transmission assets, the disposal of which is governed by environmental regulation. During 2017, the Company recorded an overall increase in AROs, including Trojan, of $6 million, with the change comprised of an increase to revisions in estimated cash flows and incurred liabilities of $2 million, accretion of $7 million, and a reduction of $3 million due to settled liabilities.

*Non-utility property* primarily represents AROs that have been recognized for portions of unregulated properties leased to third parties.

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

| | Years Ended December 31, 2017 | 2016 |
|---|---|---|
| Balance as of beginning of year | $ 161 | $ 151 |
| Liabilities incurred | 2 | 1 |
| Liabilities settled | (3) | (3) |
| Accretion expense | 7 | 7 |
| Revisions in estimated cash flows | — | 5 |
| Balance as of end of year | $ 167 | $ 161 |

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, approximately $4 million annually, 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. See "*Trust Accounts*" in Note 3, Comparative Balance Sheet Components, for additional information on the Nuclear decommissioning trust.

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.

**NOTE 8: CREDIT FACILITIES**

As of December 31, 2017, PGE had a $500 million revolving credit facility scheduled to expire in November 2021.

Pursuant to the terms of the agreement, the revolving credit facility may be used for general corporate purposes, 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 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, 2017, PGE was in compliance with this covenant with a 51.8% debt to total capital ratio.

The Company has a commercial paper program under which it may issue commercial paper for terms of up to 270 days, limited to the unused amount of credit under the revolving credit facility.

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

PGE had no borrowings outstanding and there was no commercial paper or letters of credit issued under the revolving credit facility as of December 31, 2017. As a result, as of December 31, 2017, the aggregate unused available credit capacity under the revolving credit facility was $500 million.

In addition, PGE has four letter of credit facilities that provide capacity up to a total 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, $67 million of letters of credit was outstanding, as of December 31, 2017.

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, 2020.

Short-term borrowings under these credit facilities and related interest rates are reflected in the following table (dollars in millions). The Company had no short-term borrowings during 2017.

| | Years Ended December 31, 2017 | 2016 |
|---|---|---|
| Average daily amount of short-term debt outstanding | $ — | $ 1 |
| Weighted daily average interest rate * | —% | 0.7% |
| Maximum amount outstanding during the year | $ — | $ 23 |

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

**NOTE 9: LONG-TERM DEBT**

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

| | As of December 31, 2017 | 2016 |
|---|---|---|
| **First Mortgage Bonds**, rates range from 2.51% to 9.31%, with a weighted average rate of 5.03% in 2017 and 4.86% in 2016, due at various dates through 2048 | $ 2,315 | $ 2,090 |
| **Unsecured term bank loans**, variable rates of approximately 1.87% at 11/27/2017 and 1.37% at 12/31/2016 | — | 150 |
| **Pollution Control Revenue Bonds**, 5% rate, due 2033 | 142 | 142 |
| Pollution Control Revenue Bonds owned by PGE | (21) | (21) |
| Total long-term debt | $ 2,436 | $ 2,361 |

*First Mortgage Bonds and Unsecured term bank loans*—During 2017, PGE issued a total of $225 million of FMBs and repaid long-term debt, in an aggregate amount of $150 million.

In 2017, the Company issued a total of $225 million at an interest rate of 3.98%. PGE drew $75 million in August with a maturity of 2048 and drew the remaining $150 million in November with a maturity of 2047.

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.

In 2017, PGE repaid an unsecured credit agreement under which it had borrowed $150 million from certain financial institutions. PGE repaid the loan in three separate payments as follows:

- $50 million on August 21, 2017;
- $25 million on October 30, 2017; and
- $75 million on November 27, 2017.

The term loan interest rates were set at the beginning of the interest period for periods of 1-month, 3-months, or 6-months, as selected by PGE and are based on the London Interbank Offered Rate (LIBOR) plus 63 basis points. The final rate was 1.87% as of November 27, 2017, with no other fees.

*Pollution Control Revenue Bonds*—The Company has the option to remarket through 2033 the $21 million of Pollution Control Revenue Bonds (PCBs) held by PGE as of December 31, 2017. At the time of any remarketing, the Company can choose a new interest rate period that could be daily, weekly, or a fixed term. The new interest rate would be based on market conditions at the time of remarketing. The PCBs could be backed by FMBs or a bank letter of credit depending on market conditions. Interest is payable semi-annually on PCBs.

As of December 31, 2017, the future minimum principal payments on long-term debt are as follows (in millions):

| Years ending December 31: | | |
|---|---|---|
| 2018 | $ | — |
| 2019 | | 300 |
| 2020 | | — |
| 2021 | | 160 |
| 2022 | | — |
| Thereafter | | 1,976 |
| | $ | 2,436 |

**NOTE 10: EMPLOYEE BENEFITS**

***Pension and Other Postretirement Plans***

*Defined Benefit Pension Plan*—PGE sponsors a non-contributory defined benefit pension plan, which has been closed to most new employees since January 31, 2009 and to all new employees since January 1, 2012. No changes were made to the benefits provided to existing participants when the plan was closed to new employees.

The assets of the pension plan are held in a trust and are comprised of equity and debt instruments, all of which are recorded at fair value. Pension plan calculations include several assumptions that are reviewed annually and updated as appropriate, with the measurement date of December 31.

PGE contributed $2 million to the pension plan in 2017 and made no contributions in 2016. PGE expects to contribute $21 million to the pension plan in 2018.

*Other Postretirement Benefits*—PGE has non-contributory postretirement health and life insurance plans, as well as health reimbursement arrangements (HRAs) for its employees (collectively, “Other Postretirement Benefits” in the following tables). Participants are covered under a Defined Dollar Medical Benefit Plan, which limits PGE’s obligation pursuant to the postretirement health plan by establishing a maximum benefit per employee with employees responsible for the additional cost.

The assets of these plans are held in voluntary employees’ beneficiary association trusts and are comprised of money market funds, common stocks, 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, bond, and equity mutual funds, are classified as trading and recorded at fair value. The measurement date for the NQBP is December 31.

*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. These unfunded plans include the MDCP and the Outside Directors’ Deferred Compensation Plan. 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):

| | 2017 | | | 2016 | | |
|---|---|---|---|---|---|---|
| | NQBP | Other NQBP | Total | NQBP | Other NQBP | Total |
| Non-qualified benefit plan trust | $ 17 | $ 20 | $ 37 | $ 16 | $ 18 | $ 34 |
| Non-qualified benefit plan liabilities * | 27 | 81 | 108 | 27 | 80 | 107 |

See "*Trust Accounts*" in Note 3, Comparative Balance Sheet Components, for information on the NQBP trust.

*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 implementation of the asset allocation and oversight of the benefit plan investments. The Company's investment policy 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, | | | |
|---|---|---|---|---|
| | 2017 | | 2016 | |
| | Actual | Target * | Actual | Target * |
| **Defined Benefit Pension Plan:** | | | | |
| Equity securities | 68 % | 67 % | 68 % | 67 % |
| Debt securities | 32 | 33 | 32 | 33 |
| Total | 100 % | 100 % | 100 % | 100 % |
| **Other Postretirement Benefit Plans:** | | | | |
| Equity securities | 63 % | 62 % | 60 % | 62 % |
| Debt securities | 37 | 38 | 40 | 38 |
| Total | 100 % | 100 % | 100 % | 100 % |
| **Non-Qualified Benefits Plans:** | | | | |
| Equity securities | 18 % | 12 % | 15 % | 11 % |
| Debt securities | 6 | 12 | 7 | 11 |
| Insurance contracts | 76 | 76 | 78 | 78 |
| 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. Equity securities primarily include investments across the capitalization ranges and style biases, both domestically and internationally. Fixed income securities include, but are not limited to, corporate bonds of companies from diversified industries, mortgage-backed securities, and U.S. Treasuries. Other types of investments include investments in hedge funds and private equity funds that follow several different strategies.

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.

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, 2017:** | | | | | |
| **Defined Benefit Pension Plan assets:** | | | | | |
| Equity securities—Domestic | $ 83 | $ — | $ — | $ — | $ 83 |
| Investments measured at NAV: | | | | | |
| Money market funds | — | — | — | 5 | 5 |
| Collective trust funds | — | — | — | 528 | 528 |
| Private equity funds | — | — | — | 13 | 13 |
| | $ 83 | $ — | $ — | $ 546 | $ 629 |
| **Other Postretirement Benefit Plans assets:** | | | | | |
| Money market funds | $ 3 | $ — | $ — | $ — | $ 3 |
| Equity securities: | | | | | |
| Domestic | — | 3 | — | — | 3 |
| International | 10 | — | — | — | 10 |
| Debt securities—Domestic government | — | 5 | — | — | 5 |
| Investments measured at NAV: | | | | | |
| Money market funds | — | — | — | 4 | 4 |
| Collective trust funds | — | — | — | 8 | 8 |
| | $ 13 | $ 8 | $ — | $ 12 | $ 33 |
| **As of December 31, 2016:** | | | | | |
| **Defined Benefit Pension Plan assets:** | | | | | |
| Equity securities—Domestic | $ 52 | $ — | $ — | $ — | $ 52 |
| Investments measured at NAV: | | | | | |
| Money market funds | — | — | — | 6 | 6 |
| Collective trust funds | — | — | — | 483 | 483 |
| Private equity funds | — | — | — | 18 | 18 |
| | $ 52 | $ — | $ — | $ 507 | $ 559 |
| **Other Postretirement Benefit Plans assets:** | | | | | |
| Money market funds | $ 4 | $ — | $ — | $ — | $ 4 |
| Equity securities: | | | | | |
| Domestic | — | 3 | — | — | 3 |
| International | 8 | — | — | — | 8 |
| Debt securities—Domestic government | — | 4 | — | — | 4 |
| Investments measured at NAV: | | | | | |
| Money market funds | — | — | — | 4 | 4 |
| Collective trust funds | $ — | $ — | $ — | $ 7 | $ 7 |
| | $ 12 | $ 7 | $ — | $ 11 | $ 30 |

* Assets are measured at NAV as a practical expedient and not subject to hierarchy level classification disclosure.

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

*Money market funds*—PGE invests in money market funds that seek to maintain a stable net asset value. 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.

*Collective trust funds*—Domestic and international mutual fund assets included in commingled trusts or separately managed accounts are valued at NAV as a practical expedient and not included in the fair value hierarchy.

Debt securities, including municipal debt and corporate credit securities, mortgage-backed securities, and asset-backed securities included in commingled trusts are valued at NAV as a practical expedient and not included 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.

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, 2017 and 2016. 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 | |
|---|---|---|---|---|---|---|
| | **2017** | **2016** | **2017** | **2016** | **2017** | **2016** |
| **Benefit obligation:** | | | | | | |
| As of January 1 | $ 797 | $ 758 | $ 73 | $ 81 | $ 27 | $ 27 |
| Service cost | 17 | 16 | 2 | 2 | — | — |
| Interest cost | 33 | 33 | 3 | 4 | 1 | 1 |
| Participants' contributions | — | — | 2 | 2 | — | — |
| Actuarial loss (gain) | 60 | 26 | 3 | (11) | 1 | 1 |
| Contractual termination benefits | — | — | 1 | — | — | — |
| Benefit payments | (36) | (34) | (6) | (5) | (2) | (2) |
| Administrative expenses | (2) | (2) | — | — | — | — |
| As of December 31 | $ 869 | $ 797 | $ 78 | $ 73 | $ 27 | $ 27 |
| **Fair value of plan assets:** | | | | | | |
| As of January 1 | $ 559 | $ 550 | $ 30 | $ 30 | $ 16 | $ 15 |
| Actual return on plan assets | 106 | 45 | 4 | 1 | 1 | 1 |
| Company contributions | 2 | — | 3 | 2 | 2 | 2 |
| Participants' contributions | — | — | 2 | 2 | — | — |
| Benefit payments | (36) | (34) | (6) | (5) | (2) | (2) |
| Administrative expenses | (2) | (2) | — | — | — | — |
| As of December 31 | $ 629 | $ 559 | $ 33 | $ 30 | $ 17 | $ 16 |
| **Unfunded position as of December 31** | $ (240) | $ (238) | $ (45) | $ (43) | $ (10) | $ (11) |
| **Accumulated benefit plan obligation as of December 31** | $ 778 | $ 714 | N/A | N/A | $ 27 | $ 27 |
| **Classification in Comparative Balance Sheet:** | | | | | | |
| Noncurrent asset | $ — | $ — | $ — | $ — | $ 17 | $ 16 |
| Current liability | — | — | — | — | (2) | (2) |
| Noncurrent liability | (240) | (238) | (45) | (43) | (25) | (25) |
| Net liability | $ (240) | $ (238) | $ (45) | $ (43) | $ (10) | $ (11) |
| **Amounts included in comprehensive income:** | | | | | | |
| Net actuarial loss (gain) | $ (4) | $ 21 | $ — | $ (10) | $ 1 | $ 1 |
| Amortization of net actuarial loss | (13) | (14) | — | — | (1) | (1) |
| Amortization of prior service cost | — | — | — | (1) | — | — |
| | $ (17) | $ 7 | $ — | $ (11) | $ — | $ — |
| **Amounts included in AOCL*:** | | | | | | |
| Net actuarial loss (gain) | $ 218 | $ 236 | $ (1) | $ (2) | $ 13 | $ 13 |
| Prior service cost | — | — | — | 1 | — | — |
| | $ 218 | $ 236 | $ (1) | $ (1) | $ 13 | $ 13 |

| | Defined Benefit Pension Plan | | Other Postretirement Benefits | | Non-Qualified Benefit Plans | |
|---|---|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 | 2017 | 2016 |
| **Assumptions used:** | | | | | | |
| Discount rate for benefit obligation | 3.65% | 4.17% | 3.42%-3.70% | 3.75%-4.23% | 3.65% | 4.17% |
| Discount rate for benefit cost | 4.17% | 4.36% | 3.75%-4.23% | 3.90%-4.45% | 4.17% | 4.36% |
| Weighted average rate of compensation increase for benefit obligation | 4.58% | 3.65% | 4.58% | 4.58% | N/A | N/A |
| Weighted average rate of compensation increase for benefit cost | 3.65% | 3.65% | 4.58% | 4.58% | N/A | N/A |
| Long-term rate of return on plan assets for benefit obligation | 7.50% | 7.50% | 6.26% | 6.26% | N/A | N/A |
| Long-term rate of return on plan assets for benefit cost | 7.50% | 7.50% | 6.26% | 6.29% | N/A | N/A |

* Amounts included in AOCL related to the Company's defined benefit pension plan and other postretirement benefits are transferred to Other Regulatory Assets due to the future recoverability from retail customers. Accordingly, as of the Comparative Balance Sheet date, such amounts are included in Other Regulatory Assets.

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 | |
|---|---|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 | 2017 | 2016 |
| Service cost | $ 17 | $ 16 | $ 2 | $ 2 | $ — | $ — |
| Interest cost on benefit obligation | 33 | 33 | 3 | 4 | 1 | 1 |
| Expected return on plan assets | (42) | (40) | (2) | (2) | — | — |
| Amortization of prior service cost | — | — | — | 1 | — | — |
| Amortization of net actuarial loss | 13 | 14 | — | — | 1 | 1 |
| Net periodic benefit cost | $ 21 | $ 23 | $ 3 | $ 5 | $ 2 | $ 2 |

PGE estimates that $18 million will be amortized from AOCL into net periodic benefit cost in 2018, consisting of a net actuarial loss of $17 million for pension benefits and $1 million for non-qualified benefits. Amounts related to the pension and other postretirement benefits are offset with the amortization of the corresponding regulatory asset.

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 | | | | | |
|---|---|---|---|---|---|---|
| | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 - 2027 |
| Defined benefit pension plan | $ 39 | $ 41 | $ 42 | $ 43 | $ 44 | $ 234 |
| Other postretirement benefits | 5 | 5 | 5 | 4 | 5 | 22 |
| Non-qualified benefit plans | 2 | 3 | 2 | 2 | 2 | 10 |
| Total | $ 46 | $ 49 | $ 49 | $ 49 | $ 51 | $ 266 |

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.

For measurement purposes, the assumed health care cost trend rates, which can affect amounts reported for the health care plans, were as follows:

- For 2017, 6.5% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2018, decreasing to 6.0% in 2019, then decreasing 0.25% per year thereafter, reaching 5.0% in 2023; and
- For 2016, 7% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2017, decreasing to 6.5% in 2018, then decreasing 0.25% per year thereafter, reaching 5.0% in 2023.

A one percentage point increase or decrease in the above health care cost assumption would have no material impact on total service or interest cost, or on the postretirement benefit obligation.

***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 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 $21 million in 2017 and $19 million in 2016.

**NOTE 11: INCOME TAXES**

On December 22, 2017, the TCJA was enacted and signed into law by the President of the United States with substantially all of the provisions of the TCJA having an effective date of January 1, 2018. Among other provisions, the reduction of the federal corporate tax rate from 35% to 21%, which required the Company to remeasure its existing deferred income tax balances as of December 31, 2017, had the most impact on PGE's financial condition. As a result of the Company's remeasurement, Accumulated Deferred Income Taxes on the Company's Comparative Balance Sheet were increased by $340 million.

Of the remeasurement amount, $357 million has been deferred as a regulatory liability and is expected to be refunded to customers over time. These deferred tax items relate primarily to Utility Plant and other rate base items subject to tax normalization rules that require the benefits to be passed on to customers through future prices over the remaining useful life of the underlying assets for which the deferred income taxes relate. The Company plans to use the average rate assumption method to account for the refund to customers. A portion of the remeasurement is not subject to tax normalization rules and will be amortized over time.

The remaining and offsetting remeasurement amount of $17 million represents a reduction to Accumulated Deferred Income Tax Assets related to other business items, primarily comprised of deferred tax assets related to the Company's NQBPs. The Company has recorded a $17 million charge to the results of operations, reflected as an increase in Income tax expense in the Company's Statement of Income for the period ended December 31, 2017.

Based on the Company's interpretations of the TCJA as of December 31, 2017, PGE believes it has substantially completed its analysis of the tax effects of the TCJA and has reflected such effects in the remeasurement amounts recorded. However, PGE has not yet finalized its federal tax returns for 2017 and also expects regulatory bodies, such as the U.S. Department of the Treasury, Internal Revenue Service, and OPUC to issue additional guidance or orders in 2018 that may result in changes to the Company's previously finalized analysis of the TCJA. Such changes could result in material changes to the ultimate impact of the TCJA on PGE's financial condition, results of operations, and cash flows.

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

| | Years Ended December 31, 2017 | Years Ended December 31, 2016 |
|---|---|---|
| Current: | | |
| Federal | $ 4 | $ 10 |
| State and local | 12 | 3 |
| | 16 | 13 |
| Deferred: | | |
| Federal | 61 | 23 |
| State and local | 9 | 14 |
| | 70 | 37 |
| Income tax expense | $ 86 | $ 50 |

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, 2017 | Years Ended December 31, 2016 |
|---|---|---|
| Federal statutory tax rate | 35.0% | 35.0% |
| Federal tax credits[1] | (14.0) | (18.2) |
| Change in federal tax law[2] | 6.1 | — |
| State and local taxes, net of federal tax benefit | 5.0 | 4.8 |
| Flow through depreciation and cost basis differences | 1.5 | 0.2 |
| Other | (2.1) | (1.2) |
| Effective tax rate | 31.5% | 20.6% |

(1) Federal tax credits consist primarily of production tax credits (PTCs) earned from Company-owned wind-powered generating facilities. The federal PTCs are earned based on a per-kilowatt hour rate, and as a result, the annual amount of PTCs earned will vary based on weather conditions and availability of the facilities. The PTCs are generated for 10 years from the corresponding facilities' in service dates. PGE's PTC generation ends at various dates between 2017 and 2024.

(2) Includes a $17 million increase to Income tax expense related to the remeasurement of deferred income taxes as a result of the enacted tax rate change under the TCJA.

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

| | As of December 31, 2017 | 2016 |
|---|---|---|
| Accumulated Deferred Income Tax Assets | | |
| Employee benefits | $ 128 | $ 181 |
| Price risk management | 58 | 68 |
| Regulatory liabilities | 14 | 29 |
| Tax credits | 50 | 56 |
| Depreciation and Amortization | 340 | (3) |
| Other | 17 | 26 |
| Total Deferred Income Tax Assets | 607 | 357 |
| Accumulated Deferred Income Tax Liabilities | | |
| Depreciation and amortization | 835 | 825 |
| Regulatory assets | 133 | 171 |
| Price Risk Management | 2 | 9 |
| Employee benefits | 1 | 1 |
| Other | 12 | 20 |
| Total deferred income tax liabilities | 983 | 1,026 |
| Accumulated Deferred Income Tax Liability, net | $ (376) | $ (669) |

As of December 31, 2017, PGE has federal credit carryforwards of $50 million, consisting of PTCs, which will expire at various dates through 2037. PGE has analyzed the provisions of the TCJA and its effects on the Company's deferred income tax assets, and PGE believes that it is more likely than not that its deferred income tax assets as of December 31, 2017 and 2016 will be realized; accordingly, no valuation allowance has been recorded. As of December 31, 2017 and 2016, PGE had no unrecognized tax benefits.

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

## 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 (based on fair value on the purchase date) or 1,500 shares, 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, 2017, there were 339,542 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, 2017, there were 2,470,052 shares available for future issuance pursuant to the DRIP.

## NOTE 13: STOCK-BASED COMPENSATION EXPENSE

Pursuant to the Portland General Electric Company 2006 Stock Incentive Plan (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. Service requirements generally must be met for RSUs to vest. For each grant, the number of RSUs is determined by dividing the specified award amount for each grantee by the closing stock price on the date of grant. RSU activity is summarized in the following table:

| | Units | Weighted Average Grant Date Fair Value |
|---|---|---|
| Outstanding as of December 31, 2015 | 442,993 | $ 32.84 |
| Granted | 193,734 | 35.89 |
| Forfeited | (3,044) | 28.62 |
| Vested | (174,891) | 31.47 |
| Outstanding as of December 31, 2016 | 458,792 | 34.68 |
| Granted | 202,145 | 41.96 |
| Forfeited | (64,840) | 39.57 |
| Vested | (196,721) | 31.78 |
| Outstanding as of December 31, 2017 | 399,376 | 37.98 |

A total of 4,687,500 shares of common stock were registered for issuance under the Plan, of which 3,229,476 shares remain available for future issuance as of December 31, 2017.

Outstanding RSUs provide for the payment of one Dividend Equivalent Right (DER) for each stock unit. DERs represent an amount equal to dividends paid to shareholders on a share of PGE's common stock and vest on the same schedule as the RSUs. The DERs are settled in cash (for grants to non-employee directors) or 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). The cash from the settlement of the DERs for non-employee directors may be deferred under the terms of the Portland General Electric Company 2006 Outside Directors' Deferred Compensation Plan.

*Time-based RSUs* vest in either equal installments over a one-year period on the last day of each calendar quarter, over a three-year period on each anniversary of the grant date, or at the end of a three-year period following 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 less than $1 million for the years ended December 31, 2017 and 2016.

*Performance-based RSUs* vest if performance goals are met at the end of a three-year performance period. Grants are based on three equally-weighted metrics: i) return on equity relative to allowed return on equity; ii) regulated asset base growth (applicable only for those grants made prior to 2017); and iii) a relative total shareholder return (TSR) of PGE's common stock as compared to an index of peer companies during the performance period. Vesting of performance-based RSUs is calculated by multiplying the number of units granted by a performance percentage determined by the Compensation and Human Resources Committee of PGE's Board of Directors (Committee). The performance percentage is calculated based on the extent to which the performance goals are met. In accordance with the Plan, however, the Committee may disregard or offset the effect of extraordinary, unusual or non-recurring items in determining results relative to these goals. Based on the attainment of the performance goals, the awards can range from zero to 150% of the grant.

For the return on equity and regulated asset base growth portions of the performance-based RSUs, fair value is measured based on the 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 model utilizing actual information for the common shares of PGE and its peer group for the period from the beginning of the performance period to the grant date and estimated future stock volatility over the remaining performance period. The fair value of stock-based compensation related to the TSR component of performance-based RSUs was determined using the Monte Carlo model and the following weighted average assumptions:

| | 2017 | 2016 |
|---|---|---|
| Risk-free interest rate | 1.5% | 0.9% |
| Expected dividend yield | —% | —% |
| Expected term (in years) | 3.0 | 3.0 |
| Volatility | 15.6% - 22.9% | 14.5% - 25.9% |

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 107.0% and 120.8% of awarded performance-based RSUs for the respective 2017 and 2016 grants, with an estimated 5% forfeiture rate.

The total value of performance-based RSUs vested was $6 million for the year ended December 31, 2017, $5 million for 2016, and $4 million for 2015.

*Stock-based compensation,* included in Administrative and General Expenses in the Statement of Income, was $7 million for the year ended December 31, 2017 and $6 million for 2016. Such amounts differ from those reported in Other Paid-in Capital for Stock-based compensation due primarily to the impact from the income tax payments made on behalf of employees. The Company withholds a portion of the vested shares for the payment of income taxes on behalf of the employees. Not included in Administrative and other 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 equity of $3 million in 2017 and $2 million in 2016.

As of December 31, 2017, unrecognized stock-based compensation expense was $7 million, of which approximately $5 million and $2 million is expected to be expensed in 2018 and 2019, respectively. No stock-based compensation costs have been capitalized and the Plan had no material impact on cash flows for the years ended December 31, 2017 or 2016.

## NOTE 14: COMMITMENTS AND GUARANTEES

### *Purchase Commitments*

As of December 31, 2017, PGE's estimated future minimum payments pursuant to purchase obligations for the following five years and thereafter are as follows (in millions):

| | Payments Due | | | | | | |
|---|---|---|---|---|---|---|---|
| | 2018 | 2019 | 2020 | 2021 | 2022 | Thereafter | Total |
| Capital and other purchase commitments | $ 191 | $ 2 | $ 10 | $ 2 | $ 2 | $ 58 | $ 265 |
| Purchased Power: | | | | | | | |
| Electricity purchases | 156 | 156 | 201 | 200 | 187 | 1,733 | 2,633 |
| Capacity contracts | 6 | 5 | 4 | 4 | 4 | 8 | 31 |
| Public utility districts | 9 | 17 | 16 | 16 | 15 | 85 | 158 |
| Natural gas | 51 | 35 | 28 | 25 | 24 | 140 | 303 |
| Coal and transportation | 15 | 5 | — | — | — | — | 20 |
| Total | $ 428 | $ 220 | $ 259 | $ 247 | $ 232 | $ 2,024 | $ 3,410 |

*Capital and other purchase commitments*—Certain commitments have been made for 2018 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 2044, and power capacity contracts through 2024.

*Public utility districts*—PGE has long-term power purchase agreements with certain public utility districts including, Grant County PUD for the Priest Rapids and Wanapum projects, and Douglas County PUD for the Wells project, in the state of Washington. Under the agreements, the Company is required to pay its proportionate share of the operating and debt service costs of the hydroelectric projects whether or not they are operable. In addition, although PGE's current agreement with Douglas County ends on August 31, 2018, a new contract becomes effective on September 1, 2018 that does not require contributions to Douglas County debt obligation or other costs, including the operation and maintenance costs of the projects. The new contract requires 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 loads, and included the estimated amounts in the table above. The future minimum payments for the public utility districts in the preceding table reflect the principal and capacity payments only and do not include interest, operation, or maintenance expenses.

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

| | Revenue Bonds as of December 31, 2017 | PGE's Share as of December 31, 2017 | | Contract Expiration | PGE Cost, including Debt Service | |
|---|---|---|---|---|---|---|
| | | Output | Capacity (in MW) | | 2017 | 2016 |
| Priest Rapids and Wanapum | $ 1,269 | 8.6% | 163 | 2052 | $ 16 | $ 16 |
| Wells | 160 | 19.4 | 150 | 2018 | 11 | 10 |
| Portland Hydro | — | — | — | 2017 | 1 | 1 |

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 allocated up to a cumulative maximum of 25% of the defaulting purchaser's percentage through August 2018, after which 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. The Company also has a natural gas storage agreement for the purpose of fueling the Company's Port Westward Unit 1 (PW1), PW2, and Beaver natural gas-fired generating plants.

*Coal and transportation*—PGE has coal and related rail transportation agreements with take-or-pay provisions related to Boardman that expire at various dates through 2020.

***Lease Obligations***

As of December 31, 2017, PGE's estimated future minimum lease payments pursuant to capital, build-to-suit, and operating leases for the following five years and thereafter are as follows (in millions):

| | Future Minimum Lease Payments | | |
|---|---|---|---|
| | **Capital Leases** | **Build-to-Suit** | **Operating Leases** |
| 2018 | $ 7 | $ — | $ 9 |
| 2019 | 6 | 15 | 8 |
| 2020 | 6 | 15 | 6 |
| 2021 | 6 | 14 | 6 |
| 2022 | 5 | 14 | 8 |
| Thereafter | 72 | 260 | 165 |
| Total minimum lease payments | $ 102 | $ 318 | $ 202 |
| Less imputed interest | 51 | | |
| Present value of net minimum lease payments | $ 51 | | |
| Less current portion | 2 | | |
| Non-current portion | $ 49 | | |

*Capital Leases*—PGE has entered into agreements to purchase natural gas transportation capacity to serve Carty via a 24-mile natural gas pipeline, Carty Lateral, that was constructed to serve the Carty facility. The Company has entered into a 30-year agreement to purchase the entire capacity of Carty Lateral, which is approximately 175,000 decatherms per day. At the end of the initial contract term, the Company has the option to renew the agreement in continuous three-year increments with at least 24-months prior written notice.

As of December 31, 2017, a capital lease asset of $57 million was reflected within Utility Plant and accumulated amortization of such assets of $6 million was reflected within Accumulated Provision for Depreciation, Amortization and Depletion. The present value of the future minimum lease payments due under the agreement included $2 million within Obligations Under Capital Leases - Current and $49 million in Obligations Under Capital Leases - Noncurrent on the Comparative Balance Sheet. For ratemaking purposes capital leases are treated as operating leases; therefore, in accordance with the accounting rules for regulated operations, the amortization of the leased asset is based on the rental payments recovered from customers. Also for ratemaking purposes, such rental payments were capitalized to the Carty project prior to its in service date of July 29, 2016 and, as a result, amortization of the leased asset of $2 million and interest charges of $3 million was capitalized to CWIP. Beginning August 1, 2016, amortization of the leased asset of $1 million and interest charges of $2 million has been recorded to Purchased Power in the Statement of Income through December 31, 2016. For the year ended December 31, 2017, amortization of the leased asset of $3 million and interest charges of $4 million has been recorded to Purchased Power in the Statement of Income.

*Build-to-suit*—PGE has entered into a 30-year lease agreement with a local natural gas company, NW Natural, to expand their current natural gas storage facilities, including the development of an underground storage reservoir and construction of a new compressor station and 13-mile pipeline, which will be designed to provide no-notice storage and transportation services to PGE's PW1, PW2, and Beaver natural gas-fired generating plants. Pursuant to the agreement, on September 30, 2016, PGE issued NW Natural a Notice To Proceed with construction of the expansion project, which the gas company estimates will be completed during the winter of 2018-2019, at a cost of approximately $132 million. Due to the level of PGE's involvement during the construction period, the Company is deemed to be the owner of the assets for accounting purposes during the construction period. As a result, PGE has recorded $108 million to CWIP and a corresponding liability for the same amount to Other Deferred Credits in the Comparative Balance Sheet as of December 31, 2017. In 2016, PGE recorded $21 million to CWIP and a corresponding liability for the same amount to Other noncurrent liabilities in the Comparative Balance Sheet as of December 31, 2016. Upon completion of the facility, PGE will assess whether the assets and liabilities qualify as a successful sale-leaseback transaction in which the asset and liability are removed and accounted for as either a capital or operating lease. The table above reflects PGE's estimated future minimum lease payments pursuant to the agreement based on estimated costs and assumes three 10-year renewable options are exercised.

*Operating leases*—PGE has various operating leases associated with its headquarters and certain of its production, transmission, and support facilities that expire in various years, including the Port of St. Helens land lease, which expires in 2096 and covers the location of PW1, PW2, and Beaver. Rent expense was $9 million in 2017 and $10 million in 2016.

The future minimum operating lease payments presented is net of sublease income of $4 million in each of 2018, 2019, 2020, and 2021; and $2 million in 2022. Sublease income was $4 million in 2017 and 2016.

***Guarantees***

PGE enters into financial agreements and power and natural gas purchase and sale agreements 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, 2017, 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: JOINTLY-OWNED PLANT**

As of December 31, 2017, 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 |
|---|---|---|---|---|---|
| Boardman | 90.00 % | 1980 | $ 681 | $ 592 | $ — |
| Colstrip | 20.00 | 1986 | 546 | 351 | 5 |
| Pelton/Round Butte | 66.67 | 1958 / 1964 | 251 | 68 | 7 |
| Total | | | $ 1,478 | $ 1,011 | $ 12 |

* Excludes AROs and accumulated asset retirement removal costs.

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

**NOTE 16: 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.

The Company 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) there are significant facts in dispute; vi) there are a large number of parties (including circumstances in which it is uncertain how liability, if any, will be shared among multiple defendants); or vii) there is a wide range of potential outcomes. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution, including any possible loss, fine, penalty, or business impact.

***Carty***

In 2013, PGE entered into a turnkey engineering, procurement, and construction agreement (Construction Agreement) with Abeinsa EPC LLC, Abener Construction Services, LLC, Teyma Construction USA, LLC, and Abeinsa Abener Teyma General Partnership (collectively, the “Contractor”), affiliates of Abengoa S.A. - for the construction of the Carty natural gas-fired generating plant (Carty) located in Eastern Oregon. Liberty Mutual Insurance Company and Zurich American Insurance Company (together, the “Sureties”) provided a performance bond of $145.6 million (Performance Bond) in connection with the Construction Agreement.

In December 2015, the Company declared the Contractor in default under the Construction Agreement and terminated the Construction Agreement. Following termination of the Construction Agreement, PGE brought on new contractors and construction resumed.

Carty was placed into service on July 29, 2016 and the Company began collecting its revenue requirement in customer prices on August 1, 2016, as authorized by the OPUC, based on the approved capital cost of $514 million. Actual costs for the construction of Carty exceeded the approved amount and, as of December 31, 2017, PGE has capitalized $637 million to Utility Plant.

As the final construction cost exceeded the amount authorized by the OPUC, higher interest and Depreciation Expense than allowed in the Company’s revenue requirement has resulted. These incremental expenses are recognized in the Company’s current results of operations, as a deferral for such amounts would not be considered probable of recovery at this time, in accordance with GAAP.

As actual project costs for Carty have exceeded $514 million, the Company has incurred a higher cost of service than what is reflected in the current authorized revenue requirement amount, primarily due to higher depreciation, interest expense and legal expenses. Such incremental expenses were $14 million and $3 million for the year ended December 31, 2017 and 2016, respectively. Any amounts approved by the OPUC for recovery under the deferral filing would be recognized in earnings in the period of such approval.

Actual costs do not reflect any offsetting amounts that may be received from the Sureties, pursuant to the Performance Bond. The amounts recorded also exclude $8 million of liens and claims filed for goods and services provided under contracts with the former Contractor that remain in dispute. The Company believes these liens and claims are invalid and is contesting the liens and claims in the courts.

The incremental costs resulted from various matters relating to the resumption of construction activities following the termination of the Construction Agreement, including, among other things, completing the remaining construction work, correcting deficiencies and defects in work performed by the former Contractor, determining the remaining scope of construction, preparing work plans for contractors, identifying new contractors, negotiating contracts, and procuring additional materials.

Other items contributing to the increase include costs relating to the removal of certain liens filed on the property for goods and services provided under contracts with the former Contractor, and costs to repair equipment damage that resulted from poor storage and maintenance on the part of the former Contractor.

In July 2016, the Company requested from the OPUC a regulatory deferral for the recovery of the revenue requirement associated with the incremental capital costs for Carty starting from its in service date to the date that such amounts are approved in a subsequent regulatory proceeding. The Company has requested that the OPUC delay its review of this deferral request until all legal actions with respect to this matter, including PGE's actions against the Sureties, have been resolved.

Any amounts approved by the OPUC for recovery under the deferral filing would be recognized in earnings in the period of such approval, however there is no assurance that such recovery would be granted by the OPUC. The Company believes that costs incurred to date and capitalized in Utility Plant, in the Comparative Balance Sheet, were prudently incurred. There have been no settlement discussions with regulators related to such costs.

The Company is involved in several litigation proceedings concerning the termination of the Construction Agreement and the payment obligations of the Sureties.

PGE is seeking recovery of incremental construction costs and other damages pursuant to breach of contract claims against the Contractor and claims against the Sureties pursuant to the Performance Bond. The Sureties have denied liability in whole under the Performance Bond.

Various actions relating to this matter have been filed in the U.S. District Court for the District of Oregon (U.S. District Court), in the Ninth Circuit Court of Appeals (Ninth Circuit), and in an arbitration proceeding, including the following:

- A breach of contract claim dated March 23, 2016, Portland General Electric Company v. Liberty Mutual Insurance Company and Zurich American Insurance Company, U.S. District Court of the District of Oregon, brought by PGE against the Sureties in U.S. District Court asserting that the Sureties are responsible for the payment of all damages sustained by PGE as a result of the Contractor's breach of contract. The Company's complaint disputes the Sureties' assertion that the Company wrongfully terminated the Construction Agreement and asserts that the Sureties are responsible for the payment of all damages sustained by PGE as a result of the Sureties' breach of contract, including damages in excess of the $145.6 million stated amount of the Performance Bond. Such damages include additional costs incurred by PGE to complete Carty.

- A claim dated October 21, 2016, Portland General Electric Company v. Abeinsa EPC LLC, Abener Construction Services, LLC (formerly known as Abener Engineering and Construction Services, LLC), Teyma Construction USA LLC, and Abeinsa Abener Teyma General Partnership, U.S. District Court of the District of Oregon, brought by PGE in U.S. District Court against the Contractor for failure to satisfy its obligations under the Construction Agreement. PGE is seeking damages from the Contractor in excess of $200 million for: i) costs incurred to complete construction of Carty, settle claims with unpaid contractors and vendors, and remove liens; and ii) damages in excess of the construction costs, including a project management fee, liquidated damages under the Construction Agreement, legal fees and costs, damages due to delay of the project, warranty costs, and interest.

- A claim dated December 31, 2015, In the Matter of an Arbitration Under the Rules of the International Chamber of Commerce's Court of Arbitration, International Chamber of Commerce's Court of Arbitration, by Abengoa S.A. in the ICC arbitration proceeding alleging that the Company's termination of the Construction Agreement was wrongful and in breach of the terms of the agreement and did not give rise to any liability of Abengoa S.A.; and

- A claim by the Contractor against PGE in the ICC arbitration proceeding seeking damages of $117 million based on a claim that PGE wrongfully terminated the Construction Agreement and $44 million based on a claim that PGE failed to disclose certain information to the Contractor, in connection with the Contractor's bid submitted pursuant to the Company's request for proposals.

Following various procedural arguments in the ICC arbitration and the U.S. District Court, in July 2017, the Ninth Circuit held that the ICC arbitral tribunal had jurisdiction to determine what parties and what claims could be presented in the ICC arbitration as opposed to in court. A hearing before the ICC arbitral tribunal is expected to take place on April 9 and 10, 2018. The decision of the ICC arbitral tribunal is expected to determine the forum in which the above referenced claims will be heard.

After exhausting all remedies against the aforementioned parties, the Company intends to seek approval to recover any remaining excess amounts in customer prices in a subsequent regulatory proceeding. However, there is no assurance that such recovery would be allowed by the OPUC.

In accordance with GAAP and the Company's accounting policies, any such excess costs may be charged to expense at the time disallowance of recovery becomes probable and a reasonable estimate of the amount of such disallowance can be made. As of the date of this report, the Company has concluded that the likelihood is less than probable that a portion of the cost of Carty will be disallowed for recovery in customer prices. Accordingly, no loss has been recorded to date related to the project.

***EPA Investigation of Portland Harbor***

An investigation by the United States Environmental Protection Agency (EPA) that began in 1997 of a segment of the Willamette River known as Portland Harbor has 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 and listed 69 Potentially Responsible Parties (PRPs). PGE was included among the 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 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 has 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 on January 6, 2017. The ROD outlines the EPA's selected remediation plan to clean-up for Portland Harbor, which has an 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, for a combined discounted present value of $1.1 billion. Remediation construction costs are 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. The EPA acknowledges the estimated costs are based on data that is now outdated and that a period of pre-remedial design sampling is necessary to gather updated baseline data to better refine the remedial design and estimated cost. In December 2017, the EPA announced that four PRPs have entered into an administrative order on consent to conduct this additional sampling, which is estimated to be completed in two years. PGE is not among the four PRPs performing this sampling.

PGE is participating in a voluntary process to determine an appropriate allocation of costs amongst the PRPs. Significant uncertainties remain surrounding facts and circumstances that are integral to the determination of such an allocation percentage, including results of the pre-remedial design sampling, a final allocation methodology and data with regard to property specific activities and history of ownership of sites within Portland Harbor. Based on the above facts and remaining uncertainties, PGE cannot reasonably estimate its potential liability or determine an allocation percentage that represents PGE's portion of the liability to clean-up Portland Harbor.

Where 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. As it relates to the Portland Harbor, PGE has been participating in the Portland Harbor Natural Resource Damages assessment (NRDA) process. The EPA does not manage NRDA activities, but provides claims information and coordination support to the Natural Resource Damages (NRD) trustees. Damage assessment activities are typically conducted by a Trustee Council made up of the trustee entities for the site. The Portland Harbor NRD trustees are the National Oceanic and Atmospheric Administration, the U.S. Fish and Wildlife Service, the State of Oregon, and certain tribal entities.

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 NRD trustees are in the process of negotiating NRDA liability with several PRPs, including PGE. The Company believes that PGE's portion of NRDA liabilities related to Portland Harbor will not have a material impact on its results of operations, financial position, or cash flows.

As discussed above, significant uncertainties still remain concerning the precise boundaries for clean-up, the assignment of responsibility for clean-up costs, the final selection of a proposed remedy by the EPA, the amount of natural resource damages, and the method of allocation of costs amongst PRPs. It is probable that PGE will share in a portion of these costs. However, the Company does not currently have sufficient information to reasonably estimate the amount, or range, of its potential costs for investigation or remediation of the Portland Harbor site, although such costs could be material. The Company plans to seek recovery of any costs resulting from the Portland Harbor proceeding through claims under insurance policies and regulatory recovery in customer prices.

In July 2016, the Company filed a deferral application with the OPUC seeking the deferral of the future environmental remediation costs, as well as, seeking authorization to establish a regulatory cost recovery mechanism for such environmental costs. The Company reached an agreement with OPUC Staff and other parties regarding the details of the recovery mechanism, which the OPUC approved in the first quarter of 2017. The mechanism will allow the Company to defer and recover incurred environmental expenditures through a combination of third-party proceeds, such as insurance recoveries, and through customer prices, as necessary. The mechanism establishes annual prudency reviews of environmental expenditures and is subject to an annual earnings test.

***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 legal proceedings, lawsuits were filed against PGE on behalf of two classes of electric service customers: Dreyer, Gearhart and Kafoury Bros., LLC v. Portland General Electric Company, Marion County Circuit Court; and 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 August 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 of $33 million, including interest, which were completed in 2010. Following appeals, the 2008 Order was upheld by the Oregon Court of Appeals in February 2013 and by the OSC in October 2014.

In June 2015, based on a motion filed by PGE, the Marion County Circuit Court (Circuit Court) lifted the abatement and in July 2015, the Circuit Court heard oral argument on the Company's motion for Summary Judgment. In March 2016, the Circuit Court entered a general judgment that granted the Company's motion for Summary Judgment and dismissed all claims by the plaintiffs. On April 14, 2016, the plaintiffs appealed the Circuit Court dismissal to the Court of Appeals for the State of Oregon. Briefing on the appeal is now complete, with a Court of Appeals decision pending.

PGE believes that the October 2, 2014 OSC decision and the recent Circuit Court decisions have reduced the risk of a loss to the Company in excess of the amounts previously recorded and discussed above. However, because the class actions remain subject to a decision in the appeal, management believes that it is reasonably possible that such a loss to the Company could result. As these matters involve unsettled legal theories and have a broad range of potential outcomes, sufficient information is currently not available to determine the amount of any such loss.

***Deschutes River Alliance Clean Water Act Claims***

On August 12, 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, which seeks injunctive and declaratory relief against PGE under the Clean Water Act (CWA) related to alleged past and continuing violations of the CWA. Specifically, DRA claims PGE has 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 alleges 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, 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 Deschutes River's fish and wildlife habitat below the Project and harmed the economic and personal interests of DRA's members and supporters.

In September 2016, PGE filed a motion to dismiss, which asserted that the CWA does not allow citizen suits of this nature, and that the FERC has jurisdiction over all licensing issues, including the alleged CWA violations. On March 27, 2017, the court denied PGE's motion to dismiss. On April 6, 2017, PGE filed a motion with the District Court for certification to file an interlocutory appeal with the Ninth Circuit and for a stay of the District Court proceeding. The District Court granted PGE's request on May 19, 2017, but the Ninth Circuit denied the appeal on August 14, 2017. On April 7, 2017, the District Court granted an unopposed motion filed by the Confederated Tribes of Warm Springs (the Tribes) to appear in the case as a friend of the court. The Tribes share ownership of the Project with PGE, but have not been named as a defendant.

Following conferences and negotiations involving various parties, and with the expiration of the stay, the District Court Judge, on January 17, 2018, established a briefing schedule for summary judgment motions.

The Company cannot predict the outcome of this matter, but believes that it has strong defenses to DRA's claims and intends to defend against them. Because i) this matter involves novel issues of law and ii) the mechanism and costs for achieving the relief sought in DRA's claims have not yet been determined, the Company cannot, at this time, determine the likelihood of whether the outcome of this matter will result in a material 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.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

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

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

| Line No. | Item (a) | Unrealized Gains and Losses on Available-for-Sale Securities (b) | Minimum Pension Liability adjustment (net amount) (c) | Foreign Currency Hedges (d) | Other Adjustments (e) |
|---|---|---|---|---|---|
| 1 | Balance of Account 219 at Beginning of Preceding Year | | | | ( 7,922,395) |
| 2 | Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income | | | | 259,094 |
| 3 | Preceding Quarter/Year to Date Changes in Fair Value | | | | |
| 4 | Total (lines 2 and 3) | | | | 259,094 |
| 5 | Balance of Account 219 at End of Preceding Quarter/Year | | | | ( 7,663,301) |
| 6 | Balance of Account 219 at Beginning of Current Year | | | | ( 7,663,301) |
| 7 | Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income | | | | ( 242,633) |
| 8 | Current Quarter/Year to Date Changes in Fair Value | | | | |
| 9 | Total (lines 7 and 8) | | | | ( 242,633) |
| 10 | Balance of Account 219 at End of Current Quarter/Year | | | | ( 7,905,934) |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

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) | | ( 7,923,203) | [redacted] | |
| 2 | | | 259,094 | | |
| 3 | | | | | |
| 4 | | | 259,094 | 192,737,923 | 192,997,017 |
| 5 | ( 808) | | ( 7,664,109) | [redacted] | |
| 6 | ( 808) | | ( 7,664,109) | | |
| 7 | | | ( 242,633) | | |
| 8 | | | | | |
| 9 | | | ( 242,633) | 187,132,449 | 186,889,816 |
| 10 | ( 808) | | ( 7,906,742) | [redacted] | |

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

Comprised of the net amount of the actuarial valuation of $655,667 of non-qualified benefit plans net of taxes of $(396,573).

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

Comprised of the net amount of the actuarial valuation of $(350,886) of non-qualified benefit plans net of taxes of $108,253.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

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

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

| Line No. | Classification<br>(a) | Total Company for the Current Year/Quarter Ended<br>(b) | Electric<br>(c) |
|---|---|---|---|
| 1 | Utility Plant | | |
| 2 | In Service | | |
| 3 | Plant in Service (Classified) | 10,020,102,206 | 10,020,102,206 |
| 4 | Property Under Capital Leases | 56,820,000 | 56,820,000 |
| 5 | Plant Purchased or Sold | | |
| 6 | Completed Construction not Classified | | |
| 7 | Experimental Plant Unclassified | | |
| 8 | Total (3 thru 7) | 10,076,922,206 | 10,076,922,206 |
| 9 | Leased to Others | | |
| 10 | Held for Future Use | 4,615,275 | 4,615,275 |
| 11 | Construction Work in Progress | 390,550,304 | 390,550,304 |
| 12 | Acquisition Adjustments | | |
| 13 | Total Utility Plant (8 thru 12) | 10,472,087,785 | 10,472,087,785 |
| 14 | Accum Prov for Depr, Amort, & Depl | 4,663,342,841 | 4,663,342,841 |
| 15 | Net Utility Plant (13 less 14) | 5,808,744,944 | 5,808,744,944 |
| 16 | Detail of Accum Prov for Depr, Amort & Depl | | |
| 17 | In Service: | | |
| 18 | Depreciation | 4,367,815,611 | 4,367,815,611 |
| 19 | Amort & Depl of Producing Nat Gas Land/Land Right | | |
| 20 | Amort of Underground Storage Land/Land Rights | | |
| 21 | Amort of Other Utility Plant | 295,527,230 | 295,527,230 |
| 22 | Total In Service (18 thru 21) | 4,663,342,841 | 4,663,342,841 |
| 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) | 4,663,342,841 | 4,663,342,841 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

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

| Gas<br><br>(d) | Other (Specify)<br><br>(e) | Other (Specify)<br><br>(f) | Other (Specify)<br><br>(g) | Common<br><br>(h) | Line No. |
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| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## 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<br>(a) | Balance Beginning of Year<br>(b) | Changes during Year<br>Additions<br>(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 | Line |
|---|---|---|---|
| Amortization (d) | Other Reductions (Explain in a footnote) (e) | End of Year (f) | No. |
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| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

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

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of 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<br>(a) | Balance Beginning of Year<br>(b) | Additions<br>(c) |
|---|---|---|---|
| 1 | 1. INTANGIBLE PLANT | | |
| 2 | (301) Organization | | |
| 3 | (302) Franchises and Consents | 189,056,410 | 3,957,716 |
| 4 | (303) Miscellaneous Intangible Plant | 383,378,146 | 40,693,653 |
| 5 | TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4) | 572,434,556 | 44,651,369 |
| 6 | 2. PRODUCTION PLANT | | |
| 7 | A. Steam Production Plant | | |
| 8 | (310) Land and Land Rights | 4,161,715 | |
| 9 | (311) Structures and Improvements | 255,865,400 | 2,156,757 |
| 10 | (312) Boiler Plant Equipment | 595,249,330 | 17,370,369 |
| 11 | (313) Engines and Engine-Driven Generators | | |
| 12 | (314) Turbogenerator Units | 188,694,501 | 55,818 |
| 13 | (315) Accessory Electric Equipment | 55,276,806 | |
| 14 | (316) Misc. Power Plant Equipment | 14,835,772 | 119 |
| 15 | (317) Asset Retirement Costs for Steam Production | 67,707,956 | 158,372 |
| 16 | TOTAL Steam Production Plant (Enter Total of lines 8 thru 15) | 1,181,791,480 | 19,741,435 |
| 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 | 6,047,627 | 6,276 |
| 28 | (331) Structures and Improvements | 66,510,927 | 7,756,136 |
| 29 | (332) Reservoirs, Dams, and Waterways | 337,871,533 | 11,320,564 |
| 30 | (333) Water Wheels, Turbines, and Generators | 68,608,954 | 124,089 |
| 31 | (334) Accessory Electric Equipment | 18,527,528 | 320,323 |
| 32 | (335) Misc. Power PLant Equipment | 2,480,666 | 9,771 |
| 33 | (336) Roads, Railroads, and Bridges | 12,561,103 | 678,909 |
| 34 | (337) Asset Retirement Costs for Hydraulic Production | 5,128 | |
| 35 | TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34) | 512,613,466 | 20,216,068 |
| 36 | D. Other Production Plant | | |
| 37 | (340) Land and Land Rights | 48,946 | |
| 38 | (341) Structures and Improvements | 274,318,495 | 886,786 |
| 39 | (342) Fuel Holders, Products, and Accessories | 207,106,770 | 10,062,896 |
| 40 | (343) Prime Movers | | |
| 41 | (344) Generators | 2,434,034,604 | 21,104,668 |
| 42 | (345) Accessory Electric Equipment | 115,618,614 | 4,286,940 |
| 43 | (346) Misc. Power Plant Equipment | 21,232,166 | 829,533 |
| 44 | (347) Asset Retirement Costs for Other Production | 16,698,437 | |
| 45 | TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44) | 3,069,058,032 | 37,170,823 |
| 46 | TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45) | 4,763,462,978 | 77,128,326 |

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 | 13,300,374 | |
| 49 | (352) Structures and Improvements | 20,957,272 | 2,702,437 |
| 50 | (353) Station Equipment | 331,749,298 | 24,062,066 |
| 51 | (354) Towers and Fixtures | 48,741,136 | 10,666 |
| 52 | (355) Poles and Fixtures | 30,744,074 | 217,230 |
| 53 | (356) Overhead Conductors and Devices | 80,083,573 | 186,318 |
| 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) | 525,896,168 | 27,178,717 |
| 59 | 4. DISTRIBUTION PLANT | | |
| 60 | (360) Land and Land Rights | 22,365,581 | 36,566 |
| 61 | (361) Structures and Improvements | 41,982,206 | 957,346 |
| 62 | (362) Station Equipment | 486,856,077 | 43,304,942 |
| 63 | (363) Storage Battery Equipment | 384,933 | |
| 64 | (364) Poles, Towers, and Fixtures | 364,825,631 | 29,095,008 |
| 65 | (365) Overhead Conductors and Devices | 604,089,624 | 29,077,103 |
| 66 | (366) Underground Conduit | 15,768,752 | 112,784 |
| 67 | (367) Underground Conductors and Devices | 754,024,770 | 36,613,811 |
| 68 | (368) Line Transformers | 377,593,288 | 42,558,039 |
| 69 | (369) Services | 423,397,795 | 22,906,497 |
| 70 | (370) Meters | 156,481,841 | 7,331,412 |
| 71 | (371) Installations on Customer Premises | 376,133 | |
| 72 | (372) Leased Property on Customer Premises | | |
| 73 | (373) Street Lighting and Signal Systems | 85,490,077 | 6,108,695 |
| 74 | (374) Asset Retirement Costs for Distribution Plant | 476,732 | |
| 75 | TOTAL Distribution Plant (Enter Total of lines 60 thru 74) | 3,334,113,440 | 218,102,203 |
| 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 | 9,749,339 | -4,900 |
| 87 | (390) Structures and Improvements | 126,198,875 | 1,468,589 |
| 88 | (391) Office Furniture and Equipment | 122,959,448 | 29,959,853 |
| 89 | (392) Transportation Equipment | 60,649,553 | 7,624,903 |
| 90 | (393) Stores Equipment | 3,121,478 | 654,776 |
| 91 | (394) Tools, Shop and Garage Equipment | 17,057,160 | 3,390,672 |
| 92 | (395) Laboratory Equipment | 8,555,057 | 1,153,938 |
| 93 | (396) Power Operated Equipment | 39,775,248 | 1,500,855 |
| 94 | (397) Communication Equipment | 112,337,239 | 22,444,219 |
| 95 | (398) Miscellaneous Equipment | 616,290 | 224,900 |
| 96 | SUBTOTAL (Enter Total of lines 86 thru 95) | 501,019,687 | 68,417,805 |
| 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) | 501,084,976 | 68,417,805 |
| 100 | TOTAL (Accounts 101 and 106) | 9,696,992,118 | 435,478,420 |
| 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) | 9,696,992,118 | 435,478,420 |

| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

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 |
| | | | 193,014,126 | | 3 |
| 10,299,231 | | | 413,772,568 | | 4 |
| 10,299,231 | | | 606,786,694 | | 5 |
| | | | | | 6 |
| | | | | | 7 |
| | | | 4,161,715 | | 8 |
| 23,650 | | | 257,998,507 | | 9 |
| 1,654,767 | | | 610,964,932 | | 10 |
| | | | | | 11 |
| | | | 188,750,319 | | 12 |
| | | | 55,276,806 | | 13 |
| | | | 14,835,891 | | 14 |
| | | | 67,866,328 | | 15 |
| 1,678,417 | | | 1,199,854,498 | | 16 |
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| | | | | | 26 |
| | | | 6,053,903 | | 27 |
| 8,287 | | | 74,258,776 | | 28 |
| 87,940 | | | 349,104,157 | | 29 |
| 774 | | | 68,732,269 | | 30 |
| | | | 18,847,851 | | 31 |
| 14,689 | | | 2,475,748 | | 32 |
| | | | 13,240,012 | | 33 |
| | | | 5,128 | | 34 |
| 111,690 | | | 532,717,844 | | 35 |
| | | | | | 36 |
| | | | 48,946 | | 37 |
| 124,920 | | | 275,080,361 | | 38 |
| 2,074,042 | | | 215,095,624 | | 39 |
| | | | | | 40 |
| 3,474,356 | | 33,027 | 2,451,697,943 | | 41 |
| 241,911 | | | 119,663,643 | | 42 |
| 1,562 | | | 22,060,137 | | 43 |
| | | | 16,698,437 | | 44 |
| 5,916,791 | | 33,027 | 3,100,345,091 | | 45 |
| 7,706,898 | | 33,027 | 4,832,917,433 | | 46 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

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

| Retirements<br>(d) | Adjustments<br>(e) | Transfers<br>(f) | Balance at End of Year<br>(g) | | Line No. |
|---|---|---|---|---|---|
| | | | | | 47 |
| | | | 13,300,374 | | 48 |
| 14,621 | | | 23,645,088 | | 49 |
| 328,242 | | | 355,483,122 | | 50 |
| 2,154 | | | 48,749,648 | | 51 |
| 46,457 | | | 30,914,847 | | 52 |
| | | | 80,269,891 | | 53 |
| | | | | | 54 |
| | | | | | 55 |
| | | | 286,332 | | 56 |
| | | | 34,109 | | 57 |
| 391,474 | | | 552,683,411 | | 58 |
| | | | | | 59 |
| | | | 22,402,147 | | 60 |
| 34,755 | | 1,090,102 | 43,994,899 | | 61 |
| 639,360 | | 4,807 | 529,526,466 | | 62 |
| | | | 384,933 | | 63 |
| 4,469,453 | | | 389,451,186 | | 64 |
| 4,871,195 | | | 628,295,532 | | 65 |
| | | | 15,881,536 | | 66 |
| 5,434,440 | | | 785,204,141 | | 67 |
| 1,576,687 | | | 418,574,640 | | 68 |
| | | | 446,304,292 | | 69 |
| 1,925,419 | | | 161,887,834 | | 70 |
| | | | 376,133 | | 71 |
| | | | | | 72 |
| 253,134 | | -1,192 | 91,344,446 | | 73 |
| | | | 476,732 | | 74 |
| 19,204,443 | | 1,093,717 | 3,534,104,917 | | 75 |
| | | | | | 76 |
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| | | | | | 84 |
| | | | | | 85 |
| | | | 9,744,439 | | 86 |
| 319,102 | | | 127,348,362 | | 87 |
| 13,165,246 | | 393,037 | 140,147,092 | | 88 |
| 2,186,003 | | | 66,088,453 | | 89 |
| 45,808 | | | 3,730,446 | | 90 |
| 693,437 | | | 19,754,395 | | 91 |
| 10,774 | | | 9,698,221 | | 92 |
| 2,198,343 | | | 39,077,760 | | 93 |
| 422,482 | | -424,872 | 133,934,104 | | 94 |
| | | | 841,190 | | 95 |
| 19,041,195 | | -31,835 | 550,364,462 | | 96 |
| | | | | | 97 |
| | | | 65,289 | | 98 |
| 19,041,195 | | -31,835 | 550,429,751 | | 99 |
| 56,643,241 | | 1,094,909 | 10,076,922,206 | | 100 |
| | | | | | 101 |
| | | | | | 102 |
| | | | | | 103 |
| 56,643,241 | | 1,094,909 | 10,076,922,206 | | 104 |

***Schedule Page: 204 Line No.: 39 Column: g***

Includes Carty Lateral, a capital lease asset of $56.8M as of December 31,2017. PGE has entered into a long term agreement to purchase natural gas transportation that was recorded in 2016 as a capital lease in account 101.1, to serve the Carty natural gas-fired generation plant via a 24-mile natural gas pipeline.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## 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 | | | | | |
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| 46 | | | | | |
| 47 | TOTAL | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

| Line No. | Description and Location Of Property (a) | Date Originally Included in This Account (b) | Date Expected to be used in Utility Service (c) | Balance at End of Year (d) |
|---|---|---|---|---|
| 1 | Land and Rights: | | | |
| 2 | Damascus, Clackamas County, OR | 2007 | Future | 543,591 |
| 3 | Sewell, Washington County, OR | 2008 | Future | 2,817,507 |
| 4 | Sewell Easement, Washington County, OR | 2009 | Future | 334,928 |
| 5 | Rock Creek, Washington County, OR | 2014 | 2019 | 590,122 |
| 6 | | | | |
| 7 | Other Land and Land Rights | Various | Various | 329,127 |
| 8 | | | | |
| 9 | | | | |
| 10 | | | | |
| 11 | | | | |
| 12 | | | | |
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| 21 | Other Property: | | | |
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| 44 | | | | |
| 45 | | | | |
| 46 | | | | |
| 47 | Total | | | 4,615,275 |

***Schedule Page: 214 Line No.: 5 Column: a***

Rock Creek was previously referred to as North Bethany, prior to 2017.

| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

## CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

| Line No. | Description of Project (a) | Construction work in progress - Electric (Account 107) (b) |
|---|---|---|
| 1 | Customer Billing/Meter Data Management Software System | 113,720,535 |
| 2 | Mist Natural Gas Storage | 107,589,422 |
| 3 | Construct Marquam Substation | 56,436,836 |
| 4 | Blue Lake/Gresham - System Upgrades | 23,695,317 |
| 5 | Substation Communication Upgrade | 6,888,818 |
| 6 | Elma Capacity Addition | 6,463,531 |
| 7 | Hydro Control System Upgrade | 5,841,200 |
| 8 | Colstrip Coal Capital Project | 5,634,213 |
| 9 | Harborton Reliability Project | 4,389,200 |
| 10 | West Union - 115kV Conversion | 4,158,137 |
| 11 | McGill Sub Capacity Additions | 3,939,949 |
| 12 | Abernethy Substation Capacity Addition | 3,247,099 |
| 13 | Build New Rock Creek Substation | 3,205,441 |
| 14 | Build Timothy Lake Powerhouse | 2,357,394 |
| 15 | Round Butte Transmission Upgrades | 2,352,834 |
| 16 | Customer Underground Primary Service | 2,239,195 |
| 17 | Shute WJ2 Switchgear | 1,950,810 |
| 18 | Repower Faraday Units 1-5 | 1,866,183 |
| 19 | Substation Arc Flash Mitigation | 1,813,516 |
| 20 | Pelton Round Butte Mitigation Enhancement Fund | 1,668,552 |
| 21 | River District Infrastructure - Install Vaults and Conduits | 1,632,165 |
| 22 | West Side Hydro Structural/Reliability Upgrades | 1,519,944 |
| 23 | Upgrade and Add Revenue Quality Meters | 1,490,455 |
| 24 | World Trade Center Building 3 Plaza Level Upgrade | 1,441,037 |
| 25 | Mist Natural Gas Expansion Project Management | 1,380,955 |
| 26 | Switchyard Upgrade | 1,249,981 |
| 27 | Portland Service Center Upgrade | 1,240,287 |
| 28 | Horizon Substation Phase II Project | 1,207,600 |
| 29 | Automate Development Operations | 1,145,559 |
| 30 | Replace Kelley Point Switchgear | 1,128,219 |
| 31 | Substation Fitness Project - Replace, Repair and Upgrade Aging Substation Equipments | 1,088,382 |
| 32 | Enablon Software Upgrade | 1,008,385 |
| 33 | Distribution System Construction | 1,007,039 |
| 34 | | |
| 35 | | |
| 36 | Minor Projects, <$1 million, represents 4% of the total CWIP Balance | 14,552,114 |
| 37 | | |
| 38 | | |
| 39 | | |
| 40 | | |
| 41 | | |
| 42 | | |
| 43 | TOTAL | 390,550,304 |

**Schedule Page: 216 Line No.: 2 Column: a**

Build-to-suit - PGE has entered into a 30-year lease agreement with a local natural gas company, NW Natural, to expand their current natural gas storage facilities, including the development of an underground storage reservoir and construction of a new compressor station and 13-mile pipeline, which will be designed to provide no-notice storage and transportation services to PGE’s PW1, PW2, and Beaver natural gas-fired generating plants. Pursuant to the agreement, on September 30, 2016, PGE issued NW Natural a Notice To Proceed with construction of the expansion project, which the gas company estimates will be completed during the winter of 2018-2019, at a cost of approximately $132 million. Due to the level of PGE’s involvement during the construction period, the Company is deemed to be the owner of the assets for accounting purposes during the construction period. As a result, PGE has recorded $108 million to Account 107 Construction Work in Progress and a corresponding liability for the same amount to Account 253 Other deferred credits as of December 31, 2017. Upon completion of the facility, PGE will assess whether the assets and liabilities qualify as a successful sale-leaseback transaction in which the asset and liability are removed and accounted for as either a capital or operating lease.

**Schedule Page: 216 Line No.: 8 Column: a**

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.: 20 Column: a**

Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. Respondent's 66.67% share of the jointly owned costs is reported.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

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

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 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 | 4,110,066,095 | 4,110,066,095 | | |
| 2 | Depreciation Provisions for Year, Charged to | | | | |
| 3 | (403) Depreciation Expense | 290,673,780 | 290,673,780 | | |
| 4 | (403.1) Depreciation Expense for Asset Retirement Costs | 6,891,509 | 6,891,509 | | |
| 5 | (413) Exp. of Elec. Plt. Leas. to Others | | | | |
| 6 | Transportation Expenses-Clearing | 4,629,905 | 4,629,905 | | |
| 7 | Other Clearing Accounts | 249,231 | 249,231 | | |
| 8 | Other Accounts (Specify, details in footnote): | | | | |
| 9 | | | | | |
| 10 | TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9) | 302,444,425 | 302,444,425 | | |
| 11 | Net Charges for Plant Retired: | | | | |
| 12 | Book Cost of Plant Retired | 46,344,017 | 46,344,017 | | |
| 13 | Cost of Removal | 1,290,748 | 1,290,748 | | |
| 14 | Salvage (Credit) | 1,440,053 | 1,440,053 | | |
| 15 | TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14) | 46,194,712 | 46,194,712 | | |
| 16 | Other Debit or Cr. Items (Describe, details in footnote): | 1,499,803 | 1,499,803 | | |
| 17 | | | | | |
| 18 | Book Cost or Asset Retirement Costs Retired | | | | |
| 19 | Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18) | 4,367,815,611 | 4,367,815,611 | | |
| | **Section B. Balances at End of Year According to Functional Classification** | | | | |
| 20 | Steam Production | 939,480,858 | 939,480,858 | | |
| 21 | Nuclear Production | | | | |
| 22 | Hydraulic Production-Conventional | 218,410,623 | 218,410,623 | | |
| 23 | Hydraulic Production-Pumped Storage | | | | |
| 24 | Other Production | 721,301,028 | 721,301,028 | | |
| 25 | Transmission | 230,774,567 | 230,774,567 | | |
| 26 | Distribution | 2,028,237,016 | 2,028,237,016 | | |
| 27 | Regional Transmission and Market Operation | | | | |
| 28 | General | 229,611,519 | 229,611,519 | | |
| 29 | TOTAL (Enter Total of lines 20 thru 28) | 4,367,815,611 | 4,367,815,611 | | |

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

Depreciation associated with the movement of assets between utility and non-utility functional classes.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## 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 | | | 176,125 |
| 4 | Sub - TOTAL | | | 177,125 |
| 5 | | | | |
| 6 | Salmon Springs Hospitality Group | | | |
| 7 | Common Stock | 04/09/98 | | 10,000 |
| 8 | Equity in Earnings | | | 38,200 |
| 9 | Sub - TOTAL | | | 48,200 |
| 10 | | | | |
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| 40 | | | | |
| 41 | | | | |
| 42 | Total Cost of Account 123.1 $ 0 | | TOTAL | 225,325 |

| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

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 form investments, including such revenues form 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<br>(e) | Revenues for Year<br>(f) | Amount of Investment at End of Year<br>(g) | Gain or Loss from Investment Disposed of<br>(h) | Line No. |
|---|---|---|---|---|
| | | | | 1 |
| | | 1,000 | | 2 |
| | | 176,125 | | 3 |
| | | 177,125 | | 4 |
| | | | | 5 |
| | | | | 6 |
| | | 10,000 | | 7 |
| -81,389 | | -43,189 | | 8 |
| -81,389 | | -33,189 | | 9 |
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| | | | | 41 |
| -81,389 | | 143,936 | | 42 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

| Line No. | Account<br>(a) | Balance Beginning of Year<br>(b) | Balance End of Year<br>(c) | Department or Departments which Use Material<br>(d) |
|---|---|---|---|---|
| 1 | Fuel Stock (Account 151) | 29,885,835 | 24,167,931 | Generation |
| 2 | Fuel Stock Expenses Undistributed (Account 152) | 2,656,990 | | |
| 3 | Residuals and Extracted Products (Account 153) | | | |
| 4 | Plant Materials and Operating Supplies (Account 154) | | | |
| 5 | Assigned to - Construction (Estimated) | 12,994,979 | 16,561,746 | Distribution |
| 6 | Assigned to - Operations and Maintenance | | | |
| 7 | Production Plant (Estimated) | 23,418,346 | 24,084,962 | Generation |
| 8 | Transmission Plant (Estimated) | 268,531 | 201,356 | Transmission |
| 9 | Distribution Plant (Estimated) | 5,765,001 | 5,248,553 | Distribution |
| 10 | Regional Transmission and Market Operation Plant (Estimated) | | | |
| 11 | Assigned to - Other (provide details in footnote) | 768,904 | 2,266,799 | Power Operations |
| 12 | TOTAL Account 154 (Enter Total of lines 5 thru 11) | 43,215,761 | 48,363,416 | |
| 13 | Merchandise (Account 155) | | | |
| 14 | Other Materials and Supplies (Account 156) | | 490 | |
| 15 | Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util) | | | |
| 16 | Stores Expense Undistributed (Account 163) | 4,320,139 | 3,988,473 | |
| 17 | | | | |
| 18 | | | | |
| 19 | | | | |
| 20 | TOTAL Materials and Supplies (Per Balance Sheet) | 80,078,725 | 76,520,310 | |

***Schedule Page: 227 Line No.: 2 Column: c***

Co-fire test burn using biomass raw material occurred in 2017.

***Schedule Page: 227 Line No.: 11 Column: d***

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

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## Allowances (Accounts 158.1 and 158.2)

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

| Line No. | SO2 Allowances Inventory (Account 158.1) (a) | Current Year No. (b) | Current Year Amt. (c) | 2018 No. (d) | 2018 Amt. (e) |
|---|---|---|---|---|---|
| 1 | Balance-Beginning of Year | 46,248.00 | | 10,031.00 | |
| 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 | | | | |
| 19 | Other: | | | | |
| 20 | | | | | |
| 21 | Cost of Sales/Transfers: | | | | |
| 22 | | | | | |
| 23 | | | | | |
| 24 | | | | | |
| 25 | | | | | |
| 26 | | | | | |
| 27 | | | | | |
| 28 | Total | | | | |
| 29 | Balance-End of Year | 46,248.00 | | 10,031.00 | |
| 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) | | 12 | | |
| 45 | Gains | | | | |
| 46 | Losses | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

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/transferors 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.

| 2019 No. (f) | 2019 Amt. (g) | 2020 No. (h) | 2020 Amt. (i) | Future Years No. (j) | Future Years Amt. (k) | Totals No. (l) | Totals Amt. (m) | Line No. |
|---|---|---|---|---|---|---|---|---|
| 10,033.00 | | 10,031.00 | | 121,430.00 | | 197,773.00 | | 1 |
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| 10,033.00 | | 10,031.00 | | 121,430.00 | | 197,773.00 | | 29 |
| | | | | | | | | 30 |
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| | | | | | | | | |
| 193.15 | | 193.15 | | 4,201.85 | | 5,982.74 | | 36 |
| | | | | | | | | 37 |
| | | | | | | | | 38 |
| | | | | 193.15 | | 386.30 | | 39 |
| 193.15 | | 193.15 | | 4,008.70 | | 5,596.44 | | 40 |
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| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

Allowances (Accounts 158.1 and 158.2)

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

| Line No. | NOx Allowances Inventory (Account 158.1) (a) | Current Year No. (b) | Current Year Amt. (c) | 2018 No. (d) | 2018 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 | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

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/transferors 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.

| 2019 | | 2020 | | Future Years | | Totals | | Line No. |
|---|---|---|---|---|---|---|---|---|
| No. (f) | Amt. (g) | No. (h) | Amt. (i) | No. (j) | Amt. (k) | No. (l) | Amt. (m) | |
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| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

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 Account Charged (d) | WRITTEN OFF DURING YEAR Amount (e) | Balance at End of Year (f) |
|---|---|---|---|---|---|---|
| 1 | | | | | | |
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| 19 | | | | | | |
| 20 | TOTAL | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

| Line No. | Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a) | Total Amount of Charges (b) | Costs Recognised During Year (c) | WRITTEN OFF DURING YEAR Account Charged (d) | WRITTEN OFF DURING YEAR Amount (e) | Balance at End of Year (f) |
|---|---|---|---|---|---|---|
| 21 | | | | | | |
| 22 | Abandoned Trojan Nuclear Plant | | | | | |
| 23 | Decommissioning Costs; | 321,202,069 | 4,132,248 | 407,254 | 2,934,939 | 1,698,256 |
| 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) | | | | | |
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| 45 | | | | | | |
| 46 | | | | | | |
| 47 | | | | | | |
| 48 | | | | | | |
| 49 | TOTAL | 321,202,069 | 4,132,248 | | 2,934,939 | 1,698,256 |

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

(1) $3,500,000 - Recovery of Trojan decommissioning costs, included in retail prices, until decommissioning is complete, as authorized by OPUC (Order #07-015, dated 1/12/2007 and updated by Order #10-478, dated 12/17/2010), offset in Account 407.

(2) ($545,061) - Reclass of the noncurrent portion of the settlement proceeds from a legal matter associated with the costs of the Independent Spent Fuel Storage Installation from Account 254, Regulatory liability.

## 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 | 17-065 Ft. Rock Solar | 20,728 | 561.6 | | |
| 3 | PGE 400MW PV Interconnection | | | | |
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| 21 | **Generation Studies** | | | | |
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| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## OTHER REGULATORY ASSETS (Account 182.3)

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

| Line No. | Description and Purpose of Other Regulatory Assets<br>(a) | Balance at Beginning of Current Quarter/Year<br>(b) | Debits<br>(c) | CREDITS: Written off During the Quarter/Year Account Charged<br>(d) | CREDITS: Written off During the Period Amount<br>(e) | Balance at end of Current Quarter/Year<br>(f) |
|---|---|---|---|---|---|---|
| 1 | Tax Benefits Related to Book/Tax Basis Differences | 53,511,571 | | 282 | 13,066,252 | 40,445,319 |
| 2 | Previously Flowed to Customers | 35,675,927 | | 283 | 20,334,601 | 15,341,326 |
| 3 | (Amort. period is based on the lives of the | | | | | |
| 4 | properties, approximately 25 years.) | | | | | |
| 5 | | | | | | |
| 6 | Photovoltaic Volumetric Incentive Pilot | 110,612 | 8,794,865 | 407.3 | 8,943,952 | -38,475 |
| 7 | (per OPUC Order No. 10-198 dtd 5/28/2010) | | | | | |
| 8 | Reauthorized OPUC Order No.15-185 dtd 6/09/2015) | | | | | |
| 9 | | | | | | |
| 10 | Colstrip Common Facilities (28 year amort. ending | 107,387 | | 407.3 | 107,387 | |
| 11 | 2017, FERC OCA-AD ltr dtd 5/23/1989) | | | | | |
| 12 | | | | | | |
| 13 | Price Risk Management | 146,293,579 | 117,752,450 | 555/547 | 60,589,592 | 203,456,437 |
| 14 | | | | | | |
| 15 | Deferred Broker Settlement | ( 148,351) | 148,351 | | | |
| 16 | | | | | | |
| 17 | Intervenor Funding (original deferral per OPUC | 1,361,578 | 293,559 | 407.3 | 1,313,143 | 341,994 |
| 18 | Order No. 03-388 dtd 7/2/2003) | | | | | |
| 19 | Amortization Period (01/01/17-12/31/17) | | | | | |
| 20 | | | | | | |
| 21 | Independent Evaluator Deferral (2011) | 3 | | 182.3 | 3 | |
| 22 | | | | | | |
| 23 | Generation Plant Maintenance Deferral | 1,368,984 | | 557 | 684,492 | 684,492 |
| 24 | (per OPUC Order no. 08-601 dtd 12/29/2008; | | | | | |
| 25 | (amortization period: 1/1/2009 - 12/31/2018) | | | | | |
| 26 | | | | | | |
| 27 | Residual Deferred Account | ( 121,371) | 3 | 182.3/421 | 51,628 | -172,996 |
| 28 | (per OPUC Order No. 10-279 dtd 7/23/2010) | | | | | |
| 29 | | | | | | |
| 30 | Glass Insulator Deferral | 4,110,155 | 836,642 | 571 | 76,036 | 4,870,761 |
| 31 | (per OPUC Order No. 10-478 dtd 12/17/2010; | | | | | |
| 32 | UE 215 First Revenue Requirement Stipulation) | | | | | |
| 33 | Amortization period: 56 years | | | | | |
| 34 | | | | | | |
| 35 | Pension Funding | 235,809,834 | | 219 | 17,319,507 | 218,490,327 |
| 36 | Postretirement Funding | ( 503,388) | 493,935 | 219 | 259,883 | -269,336 |
| 37 | (per SFAS No. 158 adopted 12/31/2006; | | | | | |
| 38 | OPUC Order No. 07-051 dtd 2/12/2007) | | | | | |
| 39 | | | | | | |
| 40 | Boardman Decommissioning Balancing | 322,729 | 1,156 | 421/456 | 269,038 | 54,847 |
| 41 | (per Advice No. 11-07 dtd 05/27/2011) | | | | | |
| 42 | | | | | | |
| 43 | Automated Demand Response Cost Recovery Mechanism | | 2,236,335 | 242/431 | 1,570,766 | 665,569 |
| 44 | TOTAL | 513,975,906 | 172,758,002 | | 151,497,897 | 535,236,011 |

| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

OTHER REGULATORY ASSETS (Account 182.3)

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

| Line No. | Description and Purpose of Other Regulatory Assets<br>(a) | Balance at Beginning of Current Quarter/Year<br>(b) | Debits<br>(c) | CREDITS Written off During the Quarter/Year Account Charged<br>(d) | CREDITS Written off During the Period Amount<br>(e) | Balance at end of Current Quarter/Year<br>(f) |
|---|---|---|---|---|---|---|
| 1 | (per OPUC order No 13-059 dtd 2/26/2013 | | | | | |
| 2 | Amortization per Advice No 13-04 dtd 3/8/2013 | | | | | |
| 3 | | | | | | |
| 4 | IT O&M 2014 Deferral | 3,473,600 | | Various | 1,736,800 | 1,736,800 |
| 5 | (per OPUC GRC Order No.13-459, dtd 12/9/2013 | | | | | |
| 6 | S-9 Partial Stipulation) | | | | | |
| 7 | Amortization period 1/1/2014-12/31/2018 | | | | | |
| 8 | | | | | | |
| 9 | CET 2014 Deferral | 2,691,533 | | 903 | 1,600,000 | 1,091,533 |
| 10 | (per OPUC GRC Order No.13-459, dtd 12/9/2013 | | | | | |
| 11 | S-7 Partial Stipulation) | | | | | |
| 12 | Amortization period 1/1/2014-12/31/2018 | | | | | |
| 13 | | | | | | |
| 14 | Port Westward Major Maintenance Accrual | 2,238,618 | 3,622,967 | 553 | 4,693,810 | 1,167,775 |
| 15 | (per OPUC GRC Order No.13-459, dtd 12/9/2013) | | | | | |
| 16 | | | | | | |
| 17 | Schedule 110 Energy Efficiency | 132 | 958,828 | Various | 953,858 | 5,102 |
| 18 | (per OPUC Advice No. 10-01) | | | | | |
| 19 | | | | | | |
| 20 | TID PPA Prepaid coal unearned revenue | 695,200 | | | | 695,200 |
| 21 | (per OPUC GRC Order NO. 14-442, UE-283, | | | | | |
| 22 | and Advice No. 14-03) | | | | | |
| 23 | | | | | | |
| 24 | CET 2015 Deferral | 3,122,963 | | 903 | 1,330,301 | 1,792,662 |
| 25 | (Per OPUC GRC Order NO. 13-459, UE-266, | | | | | |
| 26 | and Advice NO. 13-03) | | | | | |
| 27 | (amortization per OPUC Order No. 14-422, | | | | | |
| 28 | dtd 12/04/2014, 2015 GRC Docket UE-283 | | | | | |
| 29 | amortization period 01/01/2015-12/31/2018) | | | | | |
| 30 | | | | | | |
| 31 | Direct Access Reg Deferral 2015 | 79,671 | 101 | 447 | 79,772 | |
| 32 | (Per OPUC GRC Order No. 15-023, UM 1301) | | | | | |
| 33 | Amortization period 1/1/16 - 12/31/16 | | | | | |
| 34 | | | | | | |
| 35 | Deferred Cost - Pricing Program (Pricing Pilot) | 1,111,858 | 868,827 | 908/421 | 38,544 | 1,942,141 |
| 36 | (Per OPUC Order No. 15-203 dtd 6/23/15, UM 1708) | | | | | |
| 37 | | | | | | |
| 38 | Deferred Cost - DLC Thermostat Nest Pilot) | 361,412 | 1,624,470 | 908/421 | 1,178,115 | 807,767 |
| 39 | (Per OPUC Order No.15-203 dtd 6/23/15, UM 1708) | | | | | |
| 40 | | | | | | |
| 41 | Residential Sch123 SNA Deferral-2016 | 1,334,522 | 29,601 | 421/456 | 797,799 | 566,324 |
| 42 | (Per OPUC Order No. 16-039 dtd 1/26/16) | | | | | |
| 43 | | | | | | |
| 44 | TOTAL | 513,975,906 | 172,758,002 | | 151,497,897 | 535,236,011 |

## OTHER REGULATORY ASSETS (Account 182.3)

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

| Line No. | Description and Purpose of Other Regulatory Assets (a) | Balance at Beginning of Current Quarter/Year (b) | Debits (c) | CREDITS Written off During the Quarter/Year Account Charged (d) | CREDITS Written off During the Period Amount (e) | Balance at end of Current Quarter/Year (f) |
|---|---|---|---|---|---|---|
| 1 | CET 2016 Deferral | 2,645,431 | | 903 | 1,558,179 | 1,087,252 |
| 2 | (Per OPUC Order No. 13-459, UE-266, | | | | | |
| 3 | amortization per OPUC GRC UE-294, | | | | | |
| 4 | amortization period 01/01/2016-12/31/2018) | | | | | |
| 5 | | | | | | |
| 6 | Direct Access Reg Deferral 2016 | 693,629 | 7,773 | 447 | 708,852 | -7,450 |
| 7 | (Per OPUC Order 16-038, UM-1301) | | | | | |
| 8 | amortization period 01/01/2017-12/31/2017 | | | | | |
| 9 | | | | | | |
| 10 | Carty Major Maintenance Accrual | 71,223 | 899,457 | 456 | 970,680 | |
| 11 | (Per OPUC Order 15-356, UE-294 dtd 11/03/15) | | | | | |
| 12 | | | | | | |
| 13 | Gresham Privilege Tax Collection Deferral | 6,960,608 | 252,987 | | | 7,213,595 |
| 14 | (Advice No. 17-05, Schedule 134, dtd 02/24/17) | | | | | |
| 15 | | | | | | |
| 16 | Portland Harbor Enviornmental | 10,596,257 | 11,294,579 | 421/456 | 11,264,907 | 10,625,929 |
| 17 | Remediation Deferral | | | | | |
| 18 | (Per OPUC Order No. 17-071 | | | | | |
| 19 | , Docket No. UM1789, dtd 03/02/17) | | | | | |
| 20 | | | | | | |
| 21 | CET 2017 Deferral | | 6,791,703 | | | 6,791,703 |
| 22 | (Per OPUC Order No. 16-487, UM-1796, | | | | | |
| 23 | dtd 12/20/06) | | | | | |
| 24 | | | | | | |
| 25 | Residential Sch123 SNA Deferral-2017 | | 14,961,429 | | | 14,961,429 |
| 26 | (reauthorized Advice No. 14-20 dtd 11/23/16) | | | | | |
| 27 | | | | | | |
| 28 | Residential Water Heater | | 60,643 | | | 60,643 |
| 29 | (Per OPUC Order 17-09, UM-1827 dtd 04/19/17) | | | | | |
| 30 | | | | | | |
| 31 | Trojan Decommissioning Deferral | | 827,341 | | | 827,341 |
| 32 | (amortization per OPUC Order No. 14-422, | | | | | |
| 33 | dtd 12/04/14) | | | | | |
| 34 | (Amortization period 01/01/15-12/31/17) | | | | | |
| 35 | | | | | | |
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| 39 | | | | | | |
| 40 | | | | | | |
| 41 | | | | | | |
| 42 | | | | | | |
| 43 | | | | | | |
| 44 | TOTAL | 513,975,906 | 172,758,002 | | 151,497,897 | 535,236,011 |

**Schedule Page: 232 Line No.: 17 Column: c**

Current year reauthorization approved through OPUC Orders:
$66,125 Order 17-003 dtd 01/05/17, Docket UM 1357
$37,442 Order 17-095 dtd 03/17/17, Docket UM 1357
$1,097 Order 17-001 dtd 01/04/17, Docket UM 1751
$59,600 Order 17-163 dtd 5/12/17, Docket UM 1789
$14,000 Order 17-278 dtd 7/20/2017
$46,000 Order 17-335 dtd 8/31/2017
$9,929 Order 17-352 dtd 9/14/2017
$26,566 Order 17-354 dtd 9/14/2017
$5,549 Order 17-430 dtd 10/24/2017
$6,000 Order 17-439 dtd 10/27/2017
$21,250 Interest Accrued in 2017

**Schedule Page: 232.1 Line No.: 4 Column: d**

Amounts charged to accounts 903,921,598,549,566.

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

Amounts charged to accounts 407.3,431 and 254.

**Schedule Page: 232.2 Line No.: 10 Column: f**

Reclassed negative balance to account 254.

## MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

| Line No. | Description of Miscellaneous Deferred Debits (a) | Balance at Beginning of Year (b) | Debits (c) | CREDITS Account Charged (d) | CREDITS Amount (e) | Balance at End of Year (f) |
|---|---|---|---|---|---|---|
| 1 | | | | | | |
| 2 | Misc. Undistributed Charges | -35,772 | 25,853,636 | various | 25,593,641 | 224,223 |
| 3 | | | | | | |
| 4 | Net Co-owner / Trust Contributi | 389,559 | 87,190,650 | varous | 87,473,486 | 106,723 |
| 5 | | | | | | |
| 6 | Deferred Rent - WTC Tenant | | | | | |
| 7 | amort. through 2021 | 628,607 | | 418 | 114,206 | 514,401 |
| 8 | | | | | | |
| 9 | Deferred Revolving Credit | | | | | |
| 10 | Agreement Fees | | | | | |
| 11 | amort. through 2020 | 841,744 | 631,098 | 431 | 293,100 | 1,179,742 |
| 12 | | | | | | |
| 13 | Dispatchable Generation | | | | | |
| 14 | various amort. periods from | | | | | |
| 15 | 2005 and extending through 2025 | 12,023,230 | 1,028,523 | 903 | 1,708,855 | 11,342,898 |
| 16 | | | | | | |
| 17 | LID Receivable from WTC Tenants | | | | | |
| 18 | amort. over 20 yrs through 2029 | 77,860 | | 418 | 5,989 | 71,871 |
| 19 | | | | | | |
| 20 | Utility Property Sales- | | | | | |
| 21 | Selling Expenses | 24,521 | | 254 | | 24,521 |
| 22 | | | | | | |
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| 46 | | | | | | |
| 47 | Misc. Work in Progress | 87,871 | | | | 617,671 |
| 48 | Deferred Regulatory Comm. Expenses (See pages 350 - 351) | | | | | |
| 49 | TOTAL | 14,037,620 | | | | 14,082,050 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

| Line No. | Description and Location (a) | Balance of Begining of Year (b) | Balance at End of Year (c) |
|---|---|---|---|
| 1 | Electric | | |
| 2 | Property Related | -7,887,113 | 336,211,293 |
| 3 | Regulatory Liabilities | 29,205,352 | 13,525,752 |
| 4 | Employee Benefits | 180,625,427 | 128,251,123 |
| 5 | Price Risk Management | 67,851,531 | 57,591,286 |
| 6 | Tax Credits & NOL's | 55,801,050 | 49,582,793 |
| 7 | Other | 27,078,937 | 17,989,261 |
| 8 | TOTAL Electric (Enter Total of lines 2 thru 7) | 352,675,184 | 603,151,508 |
| 9 | Gas | | |
| 10 | | | |
| 11 | | | |
| 12 | | | |
| 13 | | | |
| 14 | | | |
| 15 | Other | | |
| 16 | TOTAL Gas (Enter Total of lines 10 thru 15 | | |
| 17 | Other (Specify) | 4,961,379 | 3,575,601 |
| 18 | TOTAL (Acct 190) (Total of lines 8, 16 and 17) | 357,636,563 | 606,727,109 |

Notes

**Schedule Page: 234 Line No.: 2 Column: c**

The significant change in property related deferred income taxes is a result of the revaluation of deferred tax assets due to TCJA.

**Schedule Page: 234 Line No.: 7 Column: c**

Line 7 - Other

| | Ending Bal 12/31/2016 | Ending Bal 12/31/2017 |
| --- | --- | --- |
| Bad Debt Expense | $2,556,475 | $1,744,633 |
| Deferred Revenue | 5,924,751 | 3,605,073 |
| Nuclear Decommissioning Trust | 6,810,149 | 5,696,728 |
| Renewable Energy Development | 6,158,710 | 4,454,439 |
| Miscellaneous | 5,628,852 | 2,488,388 |
| Total Line 7 - Other | $27,078,937 | $17,989,261 |

**Schedule Page: 234 Line No.: 17 Column: c**

| Line 17 - Other | Ending Bal 12/31/2016 | Ending Bal 12/31/2017 |
| --- | --- | --- |
| Property Related | $4,710,348 | $3,411,501 |
| Employee Benefits | 251,031 | 164,100 |
| Total Line 17 - Other Non Utility | $4,961,379 | $3,575,601 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## CAPITAL STOCKS (Account 201 and 204)

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

| Line No. | Class and Series of Stock and Name of Stock Series<br>(a) | Number of shares Authorized by Charter<br>(b) | Par or Stated Value per share<br>(c) | Call Price at End of Year<br>(d) |
|---|---|---|---|---|
| 1 | Account 201: | | | |
| 2 | Common Stock | 160,000,000 | | |
| 3 | | | | |
| 4 | Total_Com | 160,000,000 | | |
| 5 | | | | |
| 6 | Account 204: | | | |
| 7 | No Par Value Cumulative Preferred | 30,000,000 | | |
| 8 | | | | |
| 9 | Total_Pre | 30,000,000 | | |
| 10 | | | | |
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| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

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. |
|---|---|---|---|---|---|---|
| | | AS REACQUIRED STOCK (Account 217) | | IN SINKING AND OTHER FUNDS | | |
| Shares (e) | Amount (f) | Shares (g) | Cost (h) | Shares (i) | Amount (j) | |
| | | | | | | 1 |
| 89,114,265 | 1,210,926,574 | | | | | 2 |
| | | | | | | 3 |
| 89,114,265 | 1,210,926,574 | | | | | 4 |
| | | | | | | 5 |
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| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## 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 |
| 22 | | |
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| 39 | | |
| 40 | TOTAL | 18,838,837 |

**_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.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## CAPITAL STOCK EXPENSE (Account 214)

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

| Line No. | Class and Series of Stock (a) | Balance at End of Year (b) |
|---|---|---|
| 1 | Common Stock | 23,113,532 |
| 2 | | |
| 3 | | |
| 4 | | |
| 5 | | |
| 6 | | |
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| 19 | | |
| 20 | | |
| 21 | | |
| 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 | 6.75% Series VI Due 8/1/2023 | 50,000,000 | 519,234 |
| 5 | | | 437,500 D |
| 6 | 6.875% Series VI Due 8/1/2033 | 50,000,000 | 519,257 |
| 7 | | | 437,500 D |
| 8 | 6.26% Series Due 5/1/2031 | 100,000,000 | 723,856 |
| 9 | 6.31% Series Due 5/1/2036 | 175,000,000 | 1,270,565 |
| 10 | 5.80% Series Due 6/1/2039 | 170,000,000 | 1,460,968 |
| 11 | 5.81% Series Due 10/1/2037 | 130,000,000 | 1,109,574 |
| 12 | | | 517,518 D |
| 13 | 6.10% Series Due 4/15/2019 - Order No. 09-089 03/16/2009 | 300,000,000 | 2,386,224 |
| 14 | | | 222,000 D |
| 15 | 5.43% Series Due 5/3/2040 - Order No. 09-245 06/22/2009 | 150,000,000 | 1,034,284 |
| 16 | 4.47% Series Due 6/15/2044 - Order No. 13-098 03/26/2013 | 150,000,000 | 1,113,047 |
| 17 | 4.47% Series Due 8/14/2043 - Order No. 13-098 03/26/2013 | 75,000,000 | 558,740 |
| 18 | 4.84% Series Due 12/15/2048 - Order No. 13-098 03/26/2013 | 50,000,000 | 311,154 |
| 19 | 4.74% Series Due 11/15/2042 - Order No. 13-098 03/26/2013 | 105,000,000 | 652,029 |
| 20 | 4.39% Series Due 8/15/2045 - Order No. 14-145 04/29/2014 | 100,000,000 | 645,383 |
| 21 | 4.44% Series Due 10/15/2046 - Order No. 14-145 04/29/2014 | 100,000,000 | 625,030 |
| 22 | 3.51% Series Due 11/15/2024 - Order No. 14-145 04/29/2014 | 80,000,000 | 501,502 |
| 23 | 3.55% Series Due 1/15/2030 - Order No. 14-399 11/12/2014 | 75,000,000 | 325,296 |
| 24 | 3.50% Series Due 5/15/2035 - Order No. 14-399 11/12/2014 | 70,000,000 | 305,128 |
| 25 | 2.51% Series Due 1/6/2021 - Order No. 14-399 11/12/2014 | 140,000,000 | 592,932 |
| 26 | 3.98% Series Due 11/21/2047 - Order No. 16-152 04/21/2016 | 150,000,000 | -44,757 |
| 27 | 3.98% Series Due 8/3/2048 - Order No. 16-152 04/21/2016 | 75,000,000 | -99,510 |
| 28 | | | |
| 29 | Pollution Control Bonds (Guaranteed by Company) - | | |
| 30 | Port of Morrow, OR Series 1998A 5% Due 5/1/2033 | 23,600,000 | 604,452 |
| 31 | City of Forsyth, MT Series 1998A 5% Due 5/1/2033 | 97,800,000 | 2,615,167 |
| 32 | SUBTOTAL ACCOUNT 221 | 2,436,400,000 | 19,520,650 |
| 33 | TOTAL | 2,586,483,849 | 19,565,650 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

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 | | | |
| 2 | ACCOUNT 224 - OTHER LONG TERM DEBT | | |
| 3 | Variable Interest - Libor + 63 basis pts Due 11/30/2017 - Order 16-152 04/21/2016 | 50,000,000 | 15,000 |
| 4 | Variable Interest - Libor + 63 basis pts Due 11/30/2017 - Order 16-152 04/21/2016 | 75,000,000 | 22,500 |
| 5 | Variable Interest - Libor + 63 basis pts Due 11/30/2017 - Order 16-152 04/21/2016 | 25,000,000 | 7,500 |
| 6 | City of Portland Improvement District Loan | 83,849 | |
| 7 | SUBTOTAL ACCOUNT 224 | 150,083,849 | 45,000 |
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| 31 | | | |
| 32 | | | |
| 33 | TOTAL | 2,586,483,849 | 19,565,650 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

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 Date From (f) | AMORTIZATION PERIOD Date To (g) | Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h) | Interest for Year Amount (i) | Line No. |
|---|---|---|---|---|---|---|
| | | | | | | 1 |
| | | | | | | 2 |
| 08/12/1991 | 08/11/2021 | 08/12/1991 | 08/11/2021 | 20,000,000 | 1,862,000 | 3 |
| 08/01/2003 | 08/01/2023 | 08/01/2003 | 08/01/2023 | 50,000,000 | 3,375,000 | 4 |
| | | | | | | 5 |
| 08/01/2003 | 08/01/2033 | 08/01/2003 | 08/01/2033 | 50,000,000 | 3,437,500 | 6 |
| | | | | | | 7 |
| 05/26/2006 | 05/01/2031 | 05/26/2006 | 05/01/2031 | 100,000,000 | 6,260,000 | 8 |
| 05/26/2006 | 05/01/2036 | 05/26/2006 | 05/01/2036 | 175,000,000 | 11,042,500 | 9 |
| 05/16/2007 | 06/01/2039 | 05/16/2007 | 06/01/2039 | 170,000,000 | 9,860,000 | 10 |
| 09/19/2007 | 10/01/2037 | 09/19/2007 | 10/01/2037 | 130,000,000 | 7,553,000 | 11 |
| | | | | | | 12 |
| 04/16/2009 | 04/15/2019 | 04/16/2009 | 04/15/2019 | 300,000,000 | 18,300,000 | 13 |
| | | | | | | 14 |
| 11/30/2009 | 05/03/2040 | 11/30/2009 | 05/03/2040 | 150,000,000 | 8,145,000 | 15 |
| 6/27/2013 | 06/15/2044 | 6/27/2013 | 06/15/2044 | 150,000,000 | 6,705,000 | 16 |
| 8/29/2013 | 8/14/2043 | 8/29/2013 | 8/14/2043 | 75,000,000 | 3,352,500 | 17 |
| 12/16/2013 | 12/15/2048 | 12/16/2013 | 12/15/2048 | 50,000,000 | 2,420,000 | 18 |
| 11/15/2013 | 11/15/2042 | 11/15/2013 | 11/15/2042 | 105,000,000 | 4,977,000 | 19 |
| 8/15/2014 | 8/15/2045 | 8/15/2014 | 8/15/2045 | 100,000,000 | 4,390,000 | 20 |
| 10/15/2014 | 10/15/2046 | 10/15/2014 | 10/15/2046 | 100,000,000 | 4,440,000 | 21 |
| 11/17/2014 | 11/15/2024 | 11/17/2014 | 11/15/2024 | 80,000,000 | 2,808,000 | 22 |
| 1/15/2015 | 1/15/2030 | 1/15/2015 | 1/15/2030 | 75,000,000 | 2,662,500 | 23 |
| 5/15/2015 | 5/15/2035 | 5/15/2015 | 5/15/2035 | 70,000,000 | 2,450,000 | 24 |
| 1/6/2016 | 1/6/2021 | 1/6/2016 | 1/6/2021 | 140,000,000 | 3,514,000 | 25 |
| 11/21/2017 | 11/21/2047 | 11/21/2017 | 11/21/2047 | 150,000,000 | 663,333 | 26 |
| 8/3/2017 | 8/3/2048 | 8/3/2017 | 8/3/2048 | 75,000,000 | 1,235,459 | 27 |
| | | | | | | 28 |
| | | | | | | 29 |
| 05/28/1998 | 05/01/2033 | 05/28/1998 | 05/01/2033 | 23,600,000 | 1,180,000 | 30 |
| 05/28/1998 | 05/01/2033 | 05/28/1998 | 05/01/2033 | 97,800,000 | 4,890,000 | 31 |
| | | | | 2,436,400,000 | 115,522,792 | 32 |
| | | | | 2,436,471,868 | 117,516,111 | 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 Date From (f) | AMORTIZATION PERIOD Date To (g) | Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h) | Interest for Year Amount (i) | Line No. |
|---|---|---|---|---|---|---|
| | | | | | | 1 |
| | | | | | | 2 |
| 05/04/2016 | 11/30/2017 | 05/04/2016 | 11/30/2017 | | 522,802 | 3 |
| 06/15/2016 | 11/30/2017 | 06/15/2016 | 11/30/2017 | | 1,136,646 | 4 |
| 10/31/2016 | 11/30/2017 | 10/31/2016 | 11/30/2017 | | 333,871 | 5 |
| 11/16/2009 | 11/16/2029 | | | 71,868 | | 6 |
| | | | | 71,868 | 1,993,319 | 7 |
| | | | | | | 8 |
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| | | | | | | 31 |
| | | | | | | 32 |
| | | | | 2,436,471,868 | 117,516,111 | 33 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

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

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

| Line No. | Particulars (Details)<br>(a) | Amount<br>(b) |
|---|---|---|
| 1 | Net Income for the Year (Page 117) | 187,132,449 |
| 2 | | |
| 3 | | |
| 4 | Taxable Income Not Reported on Books | |
| 5 | Depreciation, Depletion & Amortization | 22,840,249 |
| 6 | | |
| 7 | | |
| 8 | | |
| 9 | Deductions Recorded on Books Not Deducted for Return | |
| 10 | Price Risk Management and Mark-to-Market | 57,162,858 |
| 11 | Regulatory Credits | -23,422,520 |
| 12 | Other (See Footnote) | 96,386,064 |
| 13 | | |
| 14 | Income Recorded on Books Not Included in Return | |
| 15 | Depreciation, Depletion & Amortization | -17,726,709 |
| 16 | Regulatory Debits | -54,732,009 |
| 17 | Other (See Footnote) | -3,041,864 |
| 18 | | |
| 19 | Deductions on Return Not Charged Against Book Income | |
| 20 | Depreciation, Depletion & Amortization | -102,367,275 |
| 21 | State & Local Tax Deduction | -11,933,904 |
| 22 | Other (See Footnote) | -8,698,879 |
| 23 | | |
| 24 | | |
| 25 | | |
| 26 | | |
| 27 | Federal Tax Net Income | 141,598,460 |
| 28 | Show Computation of Tax: | |
| 29 | Normal Federal Current Provision Benefit @ 35% | 49,559,460 |
| 30 | Federal Energy Tax Credit | -37,277,610 |
| 31 | Alternative Minimum Tax Credit | -3,619,517 |
| 32 | RTA Adjustment | -4,450,153 |
| 33 | | |
| 34 | Total Federal Income Tax - PGE | 4,212,180 |
| 35 | | |
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| 44 | | |

**Schedule Page: 261 Line No.: 12 Column: a**

| | |
|---|---|
| Qualified NDT | 3,690,445 |
| Meals & Entertainment | 842,543 |
| Political Activity | 996,431 |
| Bad Debts | (46,899) |
| Fines and Penalties | 37,888 |
| Employee Benefits | 12,800,013 |
| Federal Tax Expense | 65,385,408 |
| Orion Contingent Royalty Payments | (97,606) |
| Unamortized loss on reacquired debt | 3,369,702 |
| Stock Incentive Plans | (2,044,429) |
| State Tax Expense | 20,636,917 |
| Deferred Revenue | (9,182,903) |
| Miscellaneous | (1,446) |
| Total Other | 96,386,064 |

**Schedule Page: 261 Line No.: 17 Column: a**

| | |
|---|---|
| Key Man Insurance Proceeds | (2,751,122) |
| Miscellaneous | (290,742) |
| Total Other | (3,041,864) |

**Schedule Page: 261 Line No.: 22 Column: a**

| | |
|---|---|
| Dividend Received Deduction | (50,000) |
| IRC Sec. 199 Domestic Production Activities Deduction | (9,690,873) |
| Renewable Energy Initiatives | 792,349 |
| Property Tax | 261,872 |
| Miscellaneous | (12,227) |
| Total Other | (8,698,879) |

| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

## 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 know, 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)<br>(a) | BALANCE AT BEGINNING OF YEAR<br>Taxes Accrued (Account 236)<br>(b) | BALANCE AT BEGINNING OF YEAR<br>Prepaid Taxes (Include in Account 165)<br>(c) | Taxes Charged During Year<br>(d) | Taxes Paid During Year<br>(e) | Adjust-ments<br>(f) |
|---|---|---|---|---|---|---|
| 1 | Federal: | | | | | |
| 2 | FERC Resale/Coord | 149,685 | | 912,736 | 864,214 | |
| 3 | Income Tax | | 1,498,663 | 4,212,181 | 6,520,416 | 37,409 |
| 4 | Foreign Insurance Excise Tax | | | | | |
| 5 | FICA (Employer Share) | 1,955,903 | | 22,256,439 | 23,022,040 | |
| 6 | Unemployment | -1,344 | | 200,240 | 138,909 | |
| 7 | Power License | 218,795 | -33,973 | 2,039,419 | 1,868,615 | |
| 8 | Superfund Tax | | | | | |
| 9 | SUBTOTAL Federal | 2,323,039 | 1,464,690 | 29,621,015 | 32,414,194 | 37,409 |
| 10 | State of Montana: | | | | | |
| 11 | Income Tax | | -32,347 | 268,002 | 257,607 | |
| 12 | Electric Energy Producers | 215,344 | | 609,978 | 640,147 | |
| 13 | Property Taxes | 3,766,546 | | 7,342,536 | 7,438,489 | |
| 14 | SUBTOTAL Montana | 3,981,890 | -32,347 | 8,220,516 | 8,336,243 | |
| 15 | State of Oregon: | | | | | |
| 16 | Corp Excise Tax | | 1,583,911 | 10,893,259 | 10,799,601 | 10,194 |
| 17 | Property Taxes | | 28,379,311 | 56,578,065 | 56,977,268 | 310,849 |
| 18 | City Taxes & Licenses | 3,428,806 | | | | |
| 19 | Public Utility Comm Fees | | | | | |
| 20 | Department of Energy | | 1,058,282 | 2,238,058 | 2,407,834 | |
| 21 | Department of Enviro Quality | 479,988 | | 536,457 | 478,839 | |
| 22 | Unemployment | 56,631 | | 2,018,539 | 1,851,005 | |
| 23 | Water Power Fee | | 564,569 | 565,988 | 590,637 | |
| 24 | Transportation Tax | 349,105 | | 1,819,809 | 1,735,360 | |
| 25 | Workers Comp Assessment | | | | | |
| 26 | County & City Income Tax | | 41,156 | 272,279 | 450,000 | 4,382 |
| 27 | SUBTOTAL Oregon | 4,314,530 | 31,627,229 | 74,922,454 | 75,290,544 | 325,425 |
| 28 | State of Washington: | | | | | |
| 29 | Property Taxes | 2,012,935 | | 2,118,221 | 1,968,182 | 34,990 |
| 30 | Sales Tax | | | | | |
| 31 | SUBTOTAL WASHINGTON | 2,012,935 | | 2,118,221 | 1,968,182 | 34,990 |
| 32 | State of Wyoming | | | | | |
| 33 | Sales Tax | | | | | |
| 34 | SUBTOTAL WYOMING | | | | | |
| 35 | State of California: | | | | | |
| 36 | Corporate Franchise Tax | | 257,887 | 375,173 | 600,000 | |
| 37 | SUBTOTAL California | | 257,887 | 375,173 | 600,000 | |
| 38 | Canada | | | | | |
| 39 | Goods & Services Tax | | | | | |
| 40 | SUBTOTAL Canada | | | | | |
| 41 | TOTAL | 12,632,394 | 33,317,459 | 115,257,379 | 118,609,163 | 397,824 |

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 |
| 201,979 | | | | | | 2 |
| | 3,769,489 | 5,389,048 | | | -1,176,867 | 3 |
| | | | | | | 4 |
| 2,721,505 | | 12,969,617 | | | | 5 |
| 59,986 | | 112,493 | | | | 6 |
| 201,590 | -218,210 | | | | | 7 |
| | | | | | | 8 |
| 3,185,060 | 3,551,279 | 18,471,158 | | | -1,176,867 | 9 |
| | | | | | | 10 |
| | -42,742 | 274,762 | | | -6,760 | 11 |
| 185,175 | | 356,306 | | | 253,672 | 12 |
| 3,670,595 | | 4,838,829 | | | | 13 |
| 3,855,770 | -42,742 | 5,469,897 | | | 246,912 | 14 |
| | | | | | | 15 |
| | 1,480,059 | 11,141,878 | | | -248,619 | 16 |
| | 28,467,665 | 53,670,781 | | | | 17 |
| 3,443,660 | | 43,018,676 | | | | 18 |
| | | | | | | 19 |
| | 1,203,917 | 2,262,201 | | | | 20 |
| 526,692 | | | | | | 21 |
| 224,166 | | 1,134,001 | | | | 22 |
| | 589,218 | | | | | 23 |
| 433,554 | | 1,022,356 | | | | 24 |
| | | 126,198 | | | | 25 |
| | 214,495 | 288,671 | | | -16,392 | 26 |
| 4,628,072 | 31,955,354 | 112,664,762 | | | -265,011 | 27 |
| | | | | | | 28 |
| 2,197,965 | | 2,118,221 | | | | 29 |
| | | | | | | 30 |
| 2,197,965 | | 2,118,221 | | | | 31 |
| | | | | | | 32 |
| | | | | | | 33 |
| | | | | | | 34 |
| | | | | | | 35 |
| | 482,714 | 379,374 | | | -4,201 | 36 |
| | 482,714 | 379,374 | | | -4,201 | 37 |
| | | | | | | 38 |
| | | | | | | 39 |
| | | | | | | 40 |
| 13,866,867 | 35,946,605 | 139,103,412 | | | -1,199,167 | 41 |

**Schedule Page: 262 Line No.: 2 Column: b**

Beginning balances for lines 2, line 7 and line 23 were restated for 2017. The restatement had no impact to the totals on line 41

**Schedule Page: 262 Line No.: 3 Column: f**

Miscellaneous Adjustment

**Schedule Page: 262 Line No.: 7 Column: b**

Beginning balances for lines 2, line 7 and line 23 were restated for 2017. The restatement had no impact to the totals on line 41

**Schedule Page: 262 Line No.: 7 Column: c**

Beginning balances for lines 2, line 7 and line 23 were restated for 2017. The restatement had no impact to the totals on line 41

**Schedule Page: 262 Line No.: 16 Column: f**

Miscellaneous Adjustment

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

| | | |
|---|---|---|
| Line 17 - Adjustments | $267,251 | Multnomah County Refund |
| | 43,328 | Bill to Others |
| | $310,849 | Total Adjustments |

**Schedule Page: 262 Line No.: 23 Column: c**

Beginning balances for lines 2, line 7 and line 23 were restated for 2017. The restatement had no impact to the totals on line 41

**Schedule Page: 262 Line No.: 26 Column: f**

Miscellaneous Adjustment

**Schedule Page: 262 Line No.: 29 Column: f**

Line 29 Adjustments $34,990 Bill to Others

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
| --- | --- | --- | --- |
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## 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) | | | | | | |
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| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

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 |
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| | | | 48 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## OTHER DEFFERED CREDITS (Account 253)

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

| Line No. | Description and Other Deferred Credits (a) | Balance at Beginning of Year (b) | DEBITS Contra Account (c) | DEBITS Amount (d) | Credits (e) | Balance at End of Year (f) |
|---|---|---|---|---|---|---|
| 1 | Tenant sub-lease security deposits | 177,148 | | | 64,523 | 241,671 |
| 2 | | | | | | |
| 3 | Deferred Liability for Transferred | 627,853 | 421 | 30,834 | | 597,019 |
| 4 | Non-Qualified Plan Benefits | | | | | |
| 5 | | | | | | |
| 6 | Reserve for Portland Harbor | 7,000,000 | | | | 7,000,000 |
| 7 | Remediation Costs | | | | | |
| 8 | | | | | | |
| 9 | TID PPA prepaid coal stock | 3,620,682 | | | 483,360 | 4,104,042 |
| 10 | | | | | | |
| 11 | Deferral of Precedent Transmission | 6,109,357 | 232 | 1,000,000 | | 5,109,357 |
| 12 | Service Agreement with DET, EDF | | | | | |
| 13 | | | | | | |
| 14 | Northwest Natural Mist Storage | 21,171,864 | | | 86,417,558 | 107,589,422 |
| 15 | Capital Lease Accrual | | | | | |
| 16 | | | | | | |
| 17 | | | | | | |
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| 45 | | | | | | |
| 46 | | | | | | |
| 47 | TOTAL | 38,706,904 | | 1,030,834 | 86,965,441 | 124,641,511 |

***Schedule Page: 269 Line No.: 11 Column: d***

Reclass current portion of accrual for Precedent Transmission Service Agreement of DET and EDF to account 232.

| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

## 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 rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.

| Line No. | Account<br>(a) | Balance at Beginning of Year<br>(b) | CHANGES DURING YEAR<br>Amounts Debited to Account 410.1<br>(c) | CHANGES DURING YEAR<br>Amounts Credited to Account 411.1<br>(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 | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/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 | Line No. |
|---|---|---|---|---|---|---|---|
| | | Debits | | Credits | | | |
| Amounts Debited to Account 410.2 (e) | Amounts Credited to Account 411.2 (f) | Account Credited (g) | Amount (h) | Account Debited (i) | Amount (j) | (k) | |
| | | | | | | | 1 |
| | | | | | | | 2 |
| | | | | | | | 3 |
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| | | | | | | | 21 |

NOTES (Continued)

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## ACCUMULATED DEFFERED 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) | CHANGES DURING YEAR Amounts Credited to Account 411.1 (d) |
|---|---|---|---|---|
| 1 | Account 282 | | | |
| 2 | Electric | 790,256,094 | 122,322,543 | 79,073,760 |
| 3 | Gas | | | |
| 4 | | | | |
| 5 | TOTAL (Enter Total of lines 2 thru 4) | 790,256,094 | 122,322,543 | 79,073,760 |
| 6 | | | | |
| 7 | | | | |
| 8 | | | | |
| 9 | TOTAL Account 282 (Enter Total of lines 5 thru | 790,256,094 | 122,322,543 | 79,073,760 |
| 10 | Classification of TOTAL | | | |
| 11 | Federal Income Tax | 644,129,140 | 98,567,207 | 66,739,299 |
| 12 | State Income Tax | 136,845,656 | 22,227,890 | 11,552,253 |
| 13 | Local Income Tax | 9,281,298 | 1,527,446 | 782,208 |

NOTES

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

3. Use footnotes as required.

| CHANGES DURING YEAR | | ADJUSTMENTS | | | | Balance at End of Year | Line No. |
|---|---|---|---|---|---|---|---|
| Amounts Debited to Account 410.2 | Amounts Credited to Account 411.2 | Debits | | Credits | | | |
| | | Account Credited | Amount | Account Debited | Amount | | |
| (e) | (f) | (g) | (h) | (i) | (j) | (k) | |
| | | | | | | | 1 |
| | | 182.3 | 60,680,659 | 254 | 47,747,111 | 820,571,329 | 2 |
| | | | | | | | 3 |
| | | | | | | | 4 |
| | | | 60,680,659 | | 47,747,111 | 820,571,329 | 5 |
| | | | | | | | 6 |
| | | | | | | | 7 |
| | | | | | | | 8 |
| | | | 60,680,659 | | 47,747,111 | 820,571,329 | 9 |
| | | | | | | | 10 |
| | | | 54,775,957 | | 41,794,592 | 662,975,683 | 11 |
| | | | 5,525,992 | | 5,587,515 | 147,582,816 | 12 |
| | | | 378,710 | | 365,004 | 10,012,830 | 13 |

NOTES (Continued)

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## ACCUMULATED DEFFERED 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<br>(a) | Balance at Beginning of Year<br>(b) | CHANGES DURING YEAR<br>Amounts Debited to Account 410.1<br>(c) | CHANGES DURING YEAR<br>Amounts Credited to Account 411.1<br>(d) |
|---|---|---|---|---|
| 1 | Account 283 | | | |
| 2 | Electric | | | |
| 3 | Property Related | 35,694,227 | | |
| 4 | Price Risk Management | 9,332,578 | 5,936,843 | 13,628,651 |
| 5 | Regulatory Assets | 170,609,196 | 126,842,830 | 164,987,872 |
| 6 | Regulatory Liabilities | | | |
| 7 | Other | 19,968,585 | 128,246,454 | 135,790,555 |
| 8 | | | | |
| 9 | TOTAL Electric (Total of lines 3 thru 8) | 235,604,586 | 261,026,127 | 314,407,078 |
| 10 | Gas | | | |
| 11 | | | | |
| 12 | | | | |
| 13 | | | | |
| 14 | | | | |
| 15 | | | | |
| 16 | | | | |
| 17 | TOTAL Gas (Total of lines 11 thru 16) | | | |
| 18 | Other | 605,944 | | |
| 19 | TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18) | 236,210,530 | 261,026,127 | 314,407,078 |
| 20 | Classification of TOTAL | | | |
| 21 | Federal Income Tax | 190,779,376 | 235,117,580 | 293,894,451 |
| 22 | State Income Tax | 42,550,869 | 24,312,732 | 19,220,383 |
| 23 | Local Income Tax | 2,880,285 | 1,595,815 | 1,292,244 |

NOTES

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

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 | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Debits | | Credits | | | | |
| Amounts Debited to Account 410.2<br>(e) | Amounts Credited to Account 411.2<br>(f) | Account Credited<br>(g) | Amount<br>(h) | Account Debited<br>(i) | Amount<br>(j) | Balance at End of Year<br>(k) | Line No. |
| | | | | | | | 1 |
| | | | | | | | 2 |
| | | 254 | 50,728,901 | 182.3 | 30,328,995 | 15,294,321 | 3 |
| | | | | | | 1,640,770 | 4 |
| | | | | | | 132,464,154 | 5 |
| | | | | | | | 6 |
| | | | | | | 12,424,484 | 7 |
| | | | | | | | 8 |
| | | | 50,728,901 | | 30,328,995 | 161,823,729 | 9 |
| | | | | | | | 10 |
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| | | | | | | | 17 |
| 3,513,277 | 3,623,909 | 254 | 88,309 | 182.3 | 153,615 | 560,618 | 18 |
| 3,513,277 | 3,623,909 | | 50,817,210 | | 30,482,610 | 162,384,347 | 19 |
| | | | | | | | 20 |
| 3,249,568 | 3,439,059 | | 43,155,702 | | 25,092,056 | 113,749,368 | 21 |
| 247,339 | 173,116 | | 7,176,924 | | 5,054,090 | 45,594,607 | 22 |
| 16,370 | 11,734 | | 484,584 | | 336,464 | 3,040,372 | 23 |

NOTES (Continued)

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

| | Balance at Beg. Of Year | Balance at End Of Year |
|---|---|---|
| ASC 715 Pension & Post Retirement | 94,125,025 | 60,010,768 |
| ASC 980 Mark-to-Market | 48,122,715 | 41,407,453 |
| Miscellaneous | 13,967,857 | 9,260,133 |
| Price Risk Mgmt Deferral | 10,396,238 | 14,543,063 |
| Decoupling | 613,301 | 4,283,366 |
| CET Deferral | 3,384,060 | 2,959,371 |
| Total Regulatory Assets | 170,609,196 | 132,464,154 |

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

| | Balance at Beg. of Year | Balance at End of Year |
|---|---|---|
| Unamortized Loss on Reacquired Debt | 8,923,029 | 5,207,755 |
| Prepaid Property Tax | 11,105,739 | 7,276,912 |
| Other | (60,183) | (60,183) |
| Total Other | 19,968,585 | 12,424,484 |

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

| | Balance at Beg. Of Year | Balance at End Of Year |
|---|---|---|
| Trust-Owned Life Insurance Gain/Loss | 302,025 | 359,152 |
| Other | 303,919 | 201,466 |
| Total Other | 605,944 | 560,618 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

OTHER REGULATORY LIABILITIES (Account 254)

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

| Line No. | Description and Purpose of Other Regulatory Liabilities<br>(a) | Balance at Begining of Current Quarter/Year<br>(b) | DEBITS Account Credited<br>(c) | DEBITS Amount<br>(d) | Credits<br>(e) | Balance at End of Current Quarter/Year<br>(f) |
|---|---|---|---|---|---|---|
| 1 | Excess Deferred Taxes | 3,221,836 | | | 329,094,988 | 332,316,824 |
| 2 | | | | | | |
| 3 | Gain on Asset Sales | 2,293,330 | | | 55,182 | 2,348,512 |
| 4 | (per OPUC Order No. 01-777 dtd 8/31/2001) | | | | | |
| 5 | | | | | | |
| 6 | Gain on Tradeable Renewable Energy Credits | 2,034,469 | 407.3 | 2,079,536 | 24,550 | -20,517 |
| 7 | (per OPUC Order No. 07-083 dtd 3/5/2007) | | | | | |
| 8 | | | | | | |
| 9 | Boardman Severance | 6,712,333 | | | 1,110,770 | 7,823,103 |
| 10 | Advice No.14-18, dtd 11/3/2014 | | | | | |
| 11 | | | | | | |
| 12 | Asset Retirement Obligations: | 49,466,823 | 407.3 | 6,684,523 | 9,426,113 | 52,208,413 |
| 13 | Balancing Account | | | | | |
| 14 | | | | | | |
| 15 | Coyote Springs Major Maintenance Deferral | 3,578,966 | 456 | 3,087,056 | 3,233,049 | 3,724,959 |
| 16 | (per OPUC Order No. 01-777 dtd 8/31/2001; | | | | | |
| 17 | reauthorization OPUC Order No. 10-478 | | | | | |
| 18 | dtd 12/17/2010) | | | | | |
| 19 | | | | | | |
| 20 | ISFSI Pollution Control Tax Credit Deferral | 1,152,693 | | | 29,880 | 1,182,573 |
| 21 | (per OPUC Order No. 05-136 dtd 3/15/2005) | | | | | |
| 22 | | | | | | |
| 23 | Zero Interest Program Loan Repayments | 2,406,927 | 254 | 968,294 | 1,255,467 | 2,694,100 |
| 24 | (per Advice No. 05-19 dtd 12/20/2005) | | | | | |
| 25 | | | | | | |
| 26 | Schedule 110 Energy Efficiency - Balancing Accout | 423,415 | | | 91,906 | 515,321 |
| 27 | (per Advice No. 07-25 dtd 5/20/2008) | | | | | |
| 28 | | | | | | |
| 29 | Sunway 3 Investment Deferral | 613,870 | 407.4 | 45,480 | | 568,390 |
| 30 | (per UM 1480 dtd 4/01/2010; | | | | | |
| 31 | (Amortization over 20 years commencing 2010) | | | | | |
| 32 | | | | | | |
| 33 | Trojan Decommissioning Deferral | 16,754,819 | 407/431 | 18,982,354 | 4,422,882 | 2,195,347 |
| 34 | (amortization per OPUC Order No.14-422, | | | | | |
| 35 | dtd 12/04/2014, 2015 GRC Docket UE-283) | | | | | |
| 36 | (Amortization period 01/01/2015-12/31/2017) | | | | | |
| 37 | | | | | | |
| 38 | PRC Acquisition | 3,375,376 | 407.4 | 204,550 | 318,566 | 3,489,392 |
| 39 | (per OPUC UE-283 Final GRC Order No.14-422, | | | | | |
| 40 | dtd 12/04/2014, Second Partial | | | | | |
| 41 | TOTAL | 98,334,688 | | 38,352,697 | 368,354,704 | 428,336,695 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## OTHER REGULATORY LIABILITIES (Account 254)

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

| Line No. | Description and Purpose of Other Regulatory Liabilities | Balance at Begining of Current Quarter/Year | DEBITS | | Credits | Balance at End of Current Quarter/Year |
|---|---|---|---|---|---|---|
| | | | Account Credited | Amount | | |
| | (a) | (b) | (c) | (d) | (e) | (f) |
| 1 | Stipulation dtd 09/02/2014) | | | | | |
| 2 | (amortization per OPUC Advice No.14-24, | | | | | |
| 3 | dtd 11/12/2014) | | | | | |
| 4 | (Amortization period 01/01/2015-12/31/2016) | | | | | |
| 5 | | | | | | |
| 6 | Port Westward 2 LTSA | 910,100 | 456 | 345,692 | 886,969 | 1,451,377 |
| 7 | (per OPUC 2015 GRC Docket UE-283, | | | | | |
| 8 | OPUC Order No.14-422, dtd 12/04/14) | | | | | |
| 9 | | | | | | |
| 10 | PPS Solar - Deferral of Gain on Sale/Leaseback | 307,068 | 456/182 | 307,068 | | |
| 11 | Property sale/leaseback (approved per OPUC Order | | | | | |
| 12 | No. 15-237, Docket UP 324 dtd 08/11/15) | | | | | |
| 13 | Gain deferral and amortization (per OPUC | | | | | |
| 14 | Order No. 15-304 dtd 10/02/15, Docket UM-1724) | | | | | |
| 15 | Project approved for inclusion in RRAAC (Sch 122) | | | | | |
| 16 | (per OPUC Order No. 15-304, Docket UE 297) | | | | | |
| 17 | (Amortization period 01/01/2016 -12/31/16) | | | | | |
| 18 | | | | | | |
| 19 | Boardman Co-Fire Biomass Test Burn | 2,501,855 | 456 | 2,429,028 | | 72,827 |
| 20 | (per OPUC Order No. 13-280 dtd 8/5/13 | | | | | |
| 21 | Updated Order No. 14-422 dtd 12/4/14) | | | | | |
| 22 | | | | | | |
| 23 | PPS Solar RRAAC Deferral | 25,865 | 182.3 | 28,462 | 2,615 | 18 |
| 24 | (per OPUC order No. 15-237 dtd 8/11/15 | | | | | |
| 25 | order No. 15-304(UM1724) dtd 10/2/15) | | | | | |
| 26 | | | | | | |
| 27 | North Fork Surface Collector | 249,006 | 456 | 261,643 | 2,908 | -9,729 |
| 28 | (per OPUC order 15-356 UE294 dtd 11/3/15) | | | | | |
| 29 | | | | | | |
| 30 | Deferred Broker Settlement | 2,305,937 | | | 666,546 | 2,972,483 |
| 31 | | | | | | |
| 32 | Direct Access Open Enrollment - 2017 | | | | 634,950 | 634,950 |
| 33 | (Per OPUC Order 17-109 UM-1301 | | | | | |
| 34 | dtd 3/21/17) | | | | | |
| 35 | | | | | | |
| 36 | Photovoltaic Volumetric Incentive Pilot | | | | 1,537,245 | 1,537,245 |
| 37 | (Per OPUC Order 10-198 dtd 5/28/10 | | | | | |
| 38 | reauthorized OPUC Order 15-185 | | | | | |
| 39 | dtd 6/09/15) | | | | | |
| 40 | | | | | | |
| 41 | TOTAL | 98,334,688 | | 38,352,697 | 368,354,704 | 428,336,695 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

OTHER REGULATORY LIABILITIES (Account 254)

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

| Line No. | Description and Purpose of Other Regulatory Liabilities | Balance at Begining of Current Quarter/Year | DEBITS | | Credits | Balance at End of Current Quarter/Year |
|---|---|---|---|---|---|---|
| | | | Account Credited | Amount | | |
| | (a) | (b) | (c) | (d) | (e) | (f) |
| 1 | Carty Major Maintenance Accrual | | 456 | 2,929,011 | 4,051,664 | 1,122,653 |
| 2 | (Per OPUC Order 15-356 UE-294 | | | | | |
| 3 | dtd 11/03/15) | | | | | |
| 4 | | | | | | |
| 5 | Portland Harbor Enviornmental Deferral | | | | 2,108,454 | 2,108,454 |
| 6 | (Per OPUC Order No. 17-071, UM-1789 | | | | | |
| 7 | dtd 03/02/17) | | | | | |
| 8 | | | | | | |
| 9 | PHP PPA Expiration 2018 AUT Refund | | | | 9,400,000 | 9,400,000 |
| 10 | (Per OPUC Order 16-494, UE-308 | | | | | |
| 11 | dtd 12/20/16) | | | | | |
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| 36 | | | | | | |
| 37 | | | | | | |
| 38 | | | | | | |
| 39 | | | | | | |
| 40 | | | | | | |
| 41 | TOTAL | 98,334,688 | | 38,352,697 | 368,354,704 | 428,336,695 |

***Schedule Page: 278 Line No.: 1 Column: e***

**Revaluation of deferred tax liability due to tax reform. The deferral is made under the requirements of the normalization rules in Internal Revenue Code §168(i)(9).**

| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

## ELECTRIC OPERATING REVENUES (Account 400)

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

| Line No. | Title of Account<br>(a) | Operating Revenues Year to Date Quarterly/Annual<br>(b) | Operating Revenues Previous year (no Quarterly)<br>(c) |
|---|---|---|---|
| 1 | Sales of Electricity | | |
| 2 | (440) Residential Sales | 900,171,801 | 837,938,465 |
| 3 | (442) Commercial and Industrial Sales | | |
| 4 | Small (or Comm.) (See Instr. 4) | 650,481,084 | 645,487,072 |
| 5 | Large (or Ind.) (See Instr. 4) | 211,588,342 | 207,677,973 |
| 6 | (444) Public Street and Highway Lighting | 11,954,183 | 12,824,132 |
| 7 | (445) Other Sales to Public Authorities | | |
| 8 | (446) Sales to Railroads and Railways | | |
| 9 | (448) Interdepartmental Sales | | |
| 10 | TOTAL Sales to Ultimate Consumers | 1,774,195,410 | 1,703,927,642 |
| 11 | (447) Sales for Resale | 122,591,295 | 123,165,759 |
| 12 | TOTAL Sales of Electricity | 1,896,786,705 | 1,827,093,401 |
| 13 | (Less) (449.1) Provision for Rate Refunds | -10,337,496 | -7,913,648 |
| 14 | TOTAL Revenues Net of Prov. for Refunds | 1,907,124,201 | 1,835,007,049 |
| 15 | Other Operating Revenues | | |
| 16 | (450) Forfeited Discounts | 3,415,326 | 2,994,617 |
| 17 | (451) Miscellaneous Service Revenues | 1,830,779 | 1,852,377 |
| 18 | (453) Sales of Water and Water Power | -26,668 | -24,166 |
| 19 | (454) Rent from Electric Property | 7,650,367 | 8,704,481 |
| 20 | (455) Interdepartmental Rents | | |
| 21 | (456) Other Electric Revenues | 94,188,112 | 82,652,310 |
| 22 | (456.1) Revenues from Transmission of Electricity of Others | 8,511,435 | 7,980,146 |
| 23 | (457.1) Regional Control Service Revenues | | |
| 24 | (457.2) Miscellaneous Revenues | | |
| 25 | | | |
| 26 | TOTAL Other Operating Revenues | 115,569,351 | 104,159,765 |
| 27 | TOTAL Electric Operating Revenues | 2,022,693,552 | 1,939,166,814 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## 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 |
| 7,879,585 | 7,347,750 | 762,211 | 752,365 | 2 |
| | | | | 3 |
| 6,869,138 | 6,860,480 | 107,635 | 106,553 | 4 |
| 2,942,938 | 2,968,238 | 267 | 258 | 5 |
| 62,619 | 71,705 | 220 | 220 | 6 |
| | | | | 7 |
| | | | | 8 |
| | | | | 9 |
| 17,754,280 | 17,248,173 | 870,333 | 859,396 | 10 |
| 3,574,665 | 3,999,098 | 36 | 39 | 11 |
| 21,328,945 | 21,247,271 | 870,369 | 859,435 | 12 |
| | | | | 13 |
| 21,328,945 | 21,247,271 | 870,369 | 859,435 | 14 |

Line 12, column (b) includes $ 2,068,000 of unbilled revenues.

Line 12, column (d) includes 2,861 MWH relating to unbilled revenues

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

Includes $16,760,202 in revenue related to the delivery of 623,048 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 2017, 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 $13,028,435 in revenue related to the delivery of 524,723 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 2016, the "transition adjustment" credits provided to many commercial 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 $19,828,473 in revenue related to the delivery of 1,340,132 megawatt hours to customers of Energy Services Suppliers (ESSs). For 2017, 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 $15,389,198 in revenue related to the delivery of 1,197,525 megawatt hours to customers of Energy Services Suppliers (ESSs). For 2016, the "transition adjustment" credits provided to many 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
Returned Payment 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
Meter Verification Charges
Reconnect Charges
Returned Check Charges
Returned Payment Charges

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

Other Electric Revenues consist of the following:

| | 2017 |
|---|---|
| RPA Balancing | $65,143,350 |
| Sch 7 and Sch 32 Sales Norm Adj | 12,083,330 |
| Transmission Resale | 8,572,788 |
| Gas Resale | 5,552,442 |
| Boardman Fire Boiler with Biomass | 2,429,028 |
| Energy Trust Contract | 2,195,411 |
| Steam Sales | 1,892,218 |
| Automated Demand Response Deferred Costs | 999,373 |
| Hydro License Implementation and Compliance | 769,672 |
| Boardman Decommissioning Balancing Account | (269,038) |
| Port Westward 2 LTSA Exp Deferral | (541,277) |
| Boardman Severence | (1,110,770) |
| Carty Major Maintenance Deferral | (1,122,653) |
| Portland Harbor Environmental Remediation | (3,560,400) |
| Other | 1,154,638 |
| | $94,188,112 |

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

Other Electric Revenues consist of the following:

| | 2016 |
|---|---|
| RPA Balancing | 70,397,215 |
| Transmission Resale | 7,002,705 |
| Portland Public Schools - Solar Panel Project | 2,646,568 |
| Energy Trust Contract | 2,270,342 |
| Sch 7 and Sch 32 Sales Norm Adj | 1,742,877 |
| Steam Sales | 1,480,084 |
| Gas Resale | 1,270,178 |
| Automated Demand Response Deferred Costs | 1,021,525 |
| Hydro License Implementation and Compliance | 512,796 |
| Boardman Decommissioning Balancing Account | (251,575) |
| Port Westward 2 LTSA Exp Deferral | (680,393) |
| Boardman Severance | (1,134,176) |
| Portland Harbor Environmental Remediation | (1,631,849) |
| Boardman Fire Boiler with Biomass | (2,501,855) |
| Other | 507,868 |
| | $82,652,310 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

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 | | | | | |
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| 43 | | | | | |
| 44 | | | | | |
| 45 | | | | | |
| 46 | TOTAL | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on 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 | Residential Sales: | | | | | |
| 2 | 6 Residential Pricing Pilot | 39,752 | 4,510,046 | 4,067 | 9,774 | 0.1135 |
| 3 | 7 Residential Service | 7,841,998 | 896,272,803 | 758,144 | 10,344 | 0.1143 |
| 4 | 15 Outdoor Area Lighting | 3,267 | 1,015,952 | | | 0.3110 |
| 5 | Residential Unbilled Revenue | -5,432 | -1,627,000 | | | 0.2995 |
| 6 | TOTAL Account 440 | 7,879,585 | 900,171,801 | 762,211 | 10,338 | 0.1142 |
| 7 | General Comm. and Ind. Sales: | | | | | |
| 8 | 15 Comm. Outdoor Lighting | 12,922 | 2,535,935 | | | 0.1962 |
| 9 | 32 Small Nonresidential | 1,657,562 | 180,570,776 | 91,084 | 18,198 | 0.1089 |
| 10 | 38 Optional Time of Day - | 32,651 | 4,175,090 | 384 | 85,029 | 0.1279 |
| 11 | Large Nonresidential | | | | | |
| 12 | 47 Irrigation - Drainage - Small | 19,750 | 3,728,981 | 2,011 | 9,821 | 0.1888 |
| 13 | 49 Irrigation - Drainage - Large | 59,506 | 7,794,280 | 1,006 | 59,151 | 0.1310 |
| 14 | 83-S Large Nonresidential | 2,891,283 | 260,375,165 | 11,465 | 252,183 | 0.0901 |
| 15 | 85-S Large Nonresidential | 2,187,029 | 173,053,770 | 1,185 | 1,845,594 | 0.0791 |
| 16 | 89-S Large Nonresidential | 9,574 | 941,312 | 1 | 9,574,000 | 0.0983 |
| 17 | 485-S COS Opt-Out - Lrg. Nonresid | | 10,834,805 | 197 | | |
| 18 | 489-S COS Opt-Out - Lrg. Nonresid | | 311,003 | 1 | | |
| 19 | 515-S DAS - Outdoor Area Lighting | | 7,374 | | | |
| 20 | 532-S DAS - Small Nonresidential | | 437,394 | 156 | | |
| 21 | 583-S DAS - Large Nonresidential | | 2,391,752 | 106 | | |
| 22 | 585-S DAS - Large Nonresidential | | 3,777,447 | 39 | | |
| 23 | Gen Comm. & Ind. Unbilled Revenue | -1,139 | -454,000 | | | 0.3986 |
| 24 | TOTAL Account 442 - Small | 6,869,138 | 650,481,084 | 107,635 | 63,819 | 0.0947 |
| 25 | Large Industrial Power Sales: | | | | | |
| 26 | 75 Partial Requirements Service | | | | | |
| 27 | 89-T Large Nonresidential | 70,949 | 5,189,053 | 5 | 14,189,800 | 0.0731 |
| 28 | 85-P Large Nonresidential | 619,319 | 45,937,448 | 174 | 3,559,305 | 0.0742 |
| 29 | 89-P Large Nonresidential | 633,275 | 42,085,561 | 16 | 39,579,688 | 0.0665 |
| 30 | 90-P Large Nonresidential | 1,609,243 | 98,073,894 | 4 | 402,310,750 | 0.0609 |
| 31 | 489-T COS Opt-Out - Lg. Nonreside | | 1,935,557 | 3 | | |
| 32 | 485-P COS Opt-Out - Lrg. Nonresid | | 6,955,998 | 48 | | |
| 33 | 489-P COS Opt-Out - Lg. Nonreside | | 10,567,072 | 13 | | |
| 34 | 585-P DAS - Large Nonresidential | | 692,759 | 4 | | |
| 35 | 589-P DAS - Large Nonresidential | | | | | |
| 36 | Large Industrial Unbilled Revenue | 10,152 | 151,000 | | | 0.0149 |
| 37 | TOTAL Account 442 - Large | 2,942,938 | 211,588,342 | 267 | 11,022,240 | 0.0719 |
| 38 | Street Lighting | | | | | |
| 39 | Various Public Street and | | | | | |
| 40 | Highway Lighting: | | | | | |
| | | | | | | |
| 41 | TOTAL Billed | 17,751,419 | 1,776,263,410 | 870,333 | 20,396 | 0.1001 |
| 42 | Total Unbilled Rev.(See Instr. 6) | 2,861 | -2,068,000 | 0 | 0 | -0.7228 |
| 43 | TOTAL | 17,754,280 | 1,774,195,410 | 870,333 | 20,399 | 0.0999 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on 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 | Street Lighting | 63,340 | 12,092,183 | 220 | 287,909 | 0.1909 |
| 2 | Street Lighting Unbilled Rev | -721 | -138,000 | | | 0.1914 |
| 3 | TOTAL Account 444 | 62,619 | 11,954,183 | 220 | 284,632 | 0.1909 |
| 4 | TOTAL Account 445 | | | | | |
| 5 | Other Sales to Public Authorities | | | | | |
| 6 | Communication Devices Electr | | | | | |
| 7 | TOTAL Account 445 | | | | | |
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| 37 | | | | | | |
| 38 | | | | | | |
| 39 | | | | | | |
| 40 | | | | | | |
| 41 | TOTAL Billed | 17,751,419 | 1,776,263,410 | 870,333 | 20,396 | 0.1001 |
| 42 | Total Unbilled Rev.(See Instr. 6) | 2,861 | -2,068,000 | 0 | 0 | -0.7228 |
| 43 | TOTAL | 17,754,280 | 1,774,195,410 | 870,333 | 20,399 | 0.0999 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## SALES FOR RESALE (Account 447)

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations) | Statistical Classifi-cation | FERC Rate Schedule or Tariff Number | Average Monthly Billing Demand (MW) | Actual Demand (MW) | |
|---|---|---|---|---|---|---|
| | | | | | Average Monthly NCP Demand | Average Monthly CP Demand |
| | (a) | (b) | (c) | (d) | (e) | (f) |
| 1 | NON-RQ SALES: | | | | | |
| 2 | Avangrid Renewables | SF | EEI | | | |
| 3 | Avista Corp | SF | WSPP-1 | | | |
| 4 | BP Energy Company | SF | PGE-11 | | | |
| 5 | Bonneville Power Administration | SF | WSPP-1 | | | |
| 6 | British Columbia Hydro & Power Auth | SF | WSPP-1 | | | |
| 7 | Brookfield Energy Marketing LP | SF | WSPP-1 | | | |
| 8 | California Independent System Operator | SF | CAISO | | | |
| 9 | California Independent System Operator | AD | CAISO | | | |
| 10 | Calpine Energy Services, L.P. | SF | EEI | | | |
| 11 | Calpine Energy Services, L.P. | OS | WSPP-1 | | | |
| 12 | Cargill Power Markets, LLC | SF | WSPP-1 | | | |
| 13 | Chelan County, PUD No. 1, Washington | SF | WSPP-1 | | | |
| 14 | Citigroup Energy Inc. | SF | WSPP-1 | | | |
| | 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 note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
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| Line No. | Name of Company or Public Authority (Footnote Affiliations) | Statistical Classifi-cation | FERC Rate Schedule or Tariff Number | Average Monthly Billing Demand (MW) | Actual Demand (MW) | |
|---|---|---|---|---|---|---|
| | | | | | Average Monthly NCP Demand | Average Monthly CP Demand |
| | (a) | (b) | (c) | (d) | (e) | (f) |
| 1 | City of Burbank | SF | WSPP-1 | | | |
| 2 | City of Glendale | SF | WSPP-1 | | | |
| 3 | City of Redding | SF | WSPP-1 | | | |
| 4 | City of Roseville | SF | WSPP-1 | | | |
| 5 | City of Vernon | OS | WSPP-1 | | | |
| 6 | Canadian Wood Products, Inc. | SF | WSPP-1 | | | |
| 7 | Clatskanie Peoples Utility District | SF | WSPP-1 | | | |
| 8 | Commerce Energy | OS | WSPP-1 | | | |
| 9 | ConocoPhillips Company | SF | WSPP-1 | | | |
| 10 | Douglas County, PUD No. 1, Washington | SF | WSPP-1 | | | |
| 11 | EDF Trading NA | SF | WSPP-1 | | | |
| 12 | Element Markets | OS | EEI | | | |
| 13 | ENMAX Energy Mktg | SF | WSPP-1 | | | |
| 14 | Energy Keepers, Inc | SF | WSPP-1 | | | |
| | | | | | | |
| | Subtotal RQ | | | 0 | 0 | 0 |
| | Subtotal non-RQ | | | 0 | 0 | 0 |
| | **Total** | | | **0** | **0** | **0** |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## SALES FOR RESALE (Account 447)

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|---|---|---|---|---|---|---|
| | | | | | Average Monthly NCP Demand | Average Monthly CP Demand |
| | (a) | (b) | (c) | (d) | (e) | (f) |
| 1 | Eugene Water & Electric Board | SF | WSPP-1 | | | |
| 2 | Exelon Generation Company, LLC | SF | EEI | | | |
| 3 | Exelon Generation Company, LLC | OS | EEI | | | |
| 4 | Gridforce Energy Management | SF | EEI | | | |
| 5 | Idaho Power Company | SF | WSPP-1 | | | |
| 6 | Just Energy Solutions | OS | WSPP-1 | | | |
| 7 | Load Balance Energy | OS | OATT | | | |
| 8 | Los Angeles Depart of Water Power | SF | WSPP-1 | | | |
| 9 | Los Angeles Depart of Water Power | AD | WSPP-1 | | | |
| 10 | Macquarie Energy LLC | SF | WSPP-1 | | | |
| 11 | Marin Clean Energy | OS | WSPP-1 | | | |
| 12 | Modesto Irrigation District | SF | WSPP-1 | | | |
| 13 | Morgan Stanley Capital Group | SF | PGE-11 | | | |
| 14 | NaturEner Power Watch, LLC | SF | WSPP-1 | | | |
| | Subtotal RQ | | | 0 | 0 | 0 |
| | Subtotal non-RQ | | | 0 | 0 | 0 |
| | **Total** | | | **0** | **0** | **0** |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
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| Line No. | Name of Company or Public Authority (Footnote Affiliations) (a) | Statistical Classifi-cation (b) | FERC Rate Schedule or Tariff Number (c) | Average Monthly Billing Demand (MW) (d) | Actual Demand (MW) Average Monthly NCP Demand (e) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | Nevada Power Company | SF | WSPP-1 | | | |
| 2 | NextEra Energy Power Marketing, LLC | SF | WSPP-1 | | | |
| 3 | NorthWestern Corporation | SF | WSPP-1 | | | |
| 4 | PacifiCorp | SF | EEI | | | |
| 5 | PacifiCorp | LU | PGE-11 | | | |
| 6 | Powerex | SF | EEI | | | |
| 7 | Public Service Company of Colorado | SF | WSPP-1 | | | |
| 8 | Public Utility District No. 1 of Clark | SF | WSPP-1 | | | |
| 9 | Public Utility District No. 1 Okanogan | SF | WSPP-1 | | | |
| 10 | Public Utility District No. 2 of Grant | SF | WSPP-1 | | | |
| 11 | Puget Sound Energy | SF | WSPP-1 | | | |
| 12 | Rainbow Energy Marketing | SF | WSPP-1 | | | |
| 13 | Sacramento Municipal Utility Distric | SF | WSPP-1 | | | |
| 14 | Seattle City Light | SF | WSPP-1 | | | |
| | Subtotal RQ | | | 0 | 0 | 0 |
| | Subtotal non-RQ | | | 0 | 0 | 0 |
| | **Total** | | | **0** | **0** | **0** |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
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| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

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|---|---|---|---|---|---|---|
| | | | | | Average Monthly NCP Demand | Average Monthly CP Demand |
| | (a) | (b) | (c) | (d) | (e) | (f) |
| 1 | Shell Energy NA | SF | PGE-11 | | | |
| 2 | Shell Energy NA | OS | WSPP-1 | | | |
| 3 | Snohomish County PUD Washington | SF | WSPP-1 | | | |
| 4 | Sonoma Clean Power Authority | OS | WSPP-1 | | | |
| 5 | Southern California Edison | SF | EEI | | | |
| 6 | Tacoma Power | SF | WSPP-1 | | | |
| 7 | Talen Energy | SF | EEI | | | |
| 8 | Tenaska | SF | WSPP-1 | | | |
| 9 | The Energy Authority | SF | WSPP-1 | | | |
| 10 | The Energy Authority | OS | WSPP-1 | | | |
| 11 | TransAlta Energy Marketing | SF | EEI | | | |
| 12 | TransCanada Energy Sales Ltd. | SF | WSPP-1 | | | |
| 13 | Turlock Irrigation District | SF | WSPP-1 | | | |
| 14 | Turlock Boardman Revenue | SF | WSPP-1 | | | |
| | Subtotal RQ | | | 0 | 0 | 0 |
| | Subtotal non-RQ | | | 0 | 0 | 0 |
| | **Total** | | | **0** | **0** | **0** |

| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

## SALES FOR RESALE (Account 447)

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

| Line No. | Name of Company or Public Authority (Footnote Affiliations)<br>(a) | Statistical Classification<br>(b) | FERC Rate Schedule or Tariff Number<br>(c) | Average Monthly Billing Demand (MW)<br>(d) | Actual Demand (MW) Average Monthly NCP Demand<br>(e) | Actual Demand (MW) Average Monthly CP Demand<br>(f) |
|---|---|---|---|---|---|---|
| 1 | Turlock Boardman Revenue | AD | WSPP-1 | | | |
| 2 | Vitol Inc. | SF | WSPP-1 | | | |
| 3 | Western Area Power Authority | SF | WSPP-1 | | | |
| 4 | | | | | | |
| 5 | Direct Access Deferral - 2017 | | | | | |
| 6 | Direct Access Amortization - 2016 | | | | | |
| 7 | | | | | | |
| 8 | NON-RQ SALES: | | | | | |
| 9 | | | | | | |
| 10 | Portland General Electric Company | SF | OA96137 | 973 | | |
| 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,iine 24.
10. Footnote entries as required and provide explanations following all required data.

| MegaWatt Hours Sold (g) | REVENUE Demand Charges ($) (h) | Energy Charges ($) (i) | Other Charges ($) (j) | Total ($) (h+i+j) (k) | Line No. |
|---|---|---|---|---|---|
| | | | | | 1 |
| 62,666 | | 1,389,169 | | 1,389,169 | 2 |
| 46,936 | | 471,599 | | 471,599 | 3 |
| 61,937 | | 2,564,491 | | 2,564,491 | 4 |
| 88,596 | | 3,314,745 | | 3,314,745 | 5 |
| 17 | | 305 | | 305 | 6 |
| 1,000 | | 28,900 | | 28,900 | 7 |
| 1,718,235 | | 50,167,121 | | 50,167,121 | 8 |
| | | | -33,578 | -33,578 | 9 |
| 62,394 | | 1,803,222 | | 1,803,222 | 10 |
| | | | 2,009,039 | 2,009,039 | 11 |
| 1,400 | | 24,800 | | 24,800 | 12 |
| 125,207 | | 3,438,650 | | 3,438,650 | 13 |
| 147,757 | | 4,209,579 | | 4,209,579 | 14 |
| 0 | 0 | 0 | 0 | 0 | |
| 3,574,840 | 6,256,410 | 105,936,639 | 10,398,246 | 122,591,295 | |
| **3,574,840** | **6,256,410** | **105,936,639** | **10,398,246** | **122,591,295** | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

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

| MegaWatt Hours Sold (g) | REVENUE Demand Charges ($) (h) | Energy Charges ($) (i) | Other Charges ($) (j) | Total ($) (h+i+j) (k) | Line No. |
|---|---|---|---|---|---|
| 2,827 | | 105,863 | | 105,863 | 1 |
| 1,398 | | 56,060 | | 56,060 | 2 |
| 4,730 | | 177,630 | | 177,630 | 3 |
| 1,031 | | 26,821 | | 26,821 | 4 |
| | | | 150,000 | 150,000 | 5 |
| 25 | | 875 | | 875 | 6 |
| 2,426 | | 47,941 | | 47,941 | 7 |
| | | | 94,760 | 94,760 | 8 |
| 29,552 | | 1,278,163 | | 1,278,163 | 9 |
| 1,818 | | 45,806 | | 45,806 | 10 |
| 3,867 | | 107,504 | | 107,504 | 11 |
| | | | 558,001 | 558,001 | 12 |
| 840 | | 28,620 | | 28,620 | 13 |
| 16,179 | | 374,525 | | 374,525 | 14 |
| 0 | 0 | 0 | 0 | 0 | |
| 3,574,840 | 6,256,410 | 105,936,639 | 10,398,246 | 122,591,295 | |
| **3,574,840** | **6,256,410** | **105,936,639** | **10,398,246** | **122,591,295** | |

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| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

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

| MegaWatt Hours Sold (g) | REVENUE Demand Charges ($) (h) | Energy Charges ($) (i) | Other Charges ($) (j) | Total ($) (h+i+j) (k) | Line No. |
|---|---|---|---|---|---|
| 13,811 | | 283,753 | | 283,753 | 1 |
| 302,289 | | 6,887,658 | | 6,887,658 | 2 |
| | | | 5,623,780 | 5,623,780 | 3 |
| 195 | | 5,542 | | 5,542 | 4 |
| 47,001 | | 830,166 | | 830,166 | 5 |
| | | | 62,500 | 62,500 | 6 |
| 8,246 | | | 706,121 | 706,121 | 7 |
| 2,075 | | 63,700 | | 63,700 | 8 |
| | | | -520,000 | -520,000 | 9 |
| 9,075 | | 224,240 | | 224,240 | 10 |
| | | | 21,340 | 21,340 | 11 |
| 13,912 | | 550,103 | | 550,103 | 12 |
| 32,413 | | 600,872 | | 600,872 | 13 |
| 134 | | 2,637 | | 2,637 | 14 |
| 0 | 0 | 0 | 0 | 0 | |
| 3,574,840 | 6,256,410 | 105,936,639 | 10,398,246 | 122,591,295 | |
| **3,574,840** | **6,256,410** | **105,936,639** | **10,398,246** | **122,591,295** | |

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SALES FOR RESALE (Account 447) (Continued)

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

| MegaWatt Hours Sold (g) | REVENUE Demand Charges ($) (h) | Energy Charges ($) (i) | Other Charges ($) (j) | Total ($) (h+i+j) (k) | Line No. |
|---|---|---|---|---|---|
| 13 | | 414 | | 414 | 1 |
| 1,115 | | 28,534 | | 28,534 | 2 |
| 127,085 | | 3,532,818 | | 3,532,818 | 3 |
| 130,680 | | 3,675,145 | | 3,675,145 | 4 |
| 16,996 | | | 72,450 | 72,450 | 5 |
| 83,929 | | 207,398 | | 207,398 | 6 |
| 68,000 | | 2,473,490 | | 2,473,490 | 7 |
| 2,126 | | 42,739 | | 42,739 | 8 |
| 745 | | 19,490 | | 19,490 | 9 |
| 24 | | 776 | | 776 | 10 |
| 29,161 | | 656,301 | | 656,301 | 11 |
| 13,206 | | 187,334 | | 187,334 | 12 |
| 8,040 | | 235,028 | | 235,028 | 13 |
| 22,217 | | 394,737 | | 394,737 | 14 |
| 0 | 0 | 0 | 0 | 0 | |
| 3,574,840 | 6,256,410 | 105,936,639 | 10,398,246 | 122,591,295 | |
| **3,574,840** | **6,256,410** | **105,936,639** | **10,398,246** | **122,591,295** | |

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|---|---|---|---|

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

| MegaWatt Hours Sold (g) | REVENUE Demand Charges ($) (h) | Energy Charges ($) (i) | Other Charges ($) (j) | Total ($) (h+i+j) (k) | Line No. |
|---|---|---|---|---|---|
| 94,648 | | 2,793,074 | | 2,793,074 | 1 |
| | | | 437,878 | 437,878 | 2 |
| 15,730 | | 425,134 | | 425,134 | 3 |
| | | | 1,059,809 | 1,059,809 | 4 |
| 1,600 | | 17,000 | | 17,000 | 5 |
| 12,522 | | 159,613 | | 159,613 | 6 |
| 1,592 | | 30,796 | | 30,796 | 7 |
| 3,400 | | 61,200 | | 61,200 | 8 |
| 80,640 | | 2,468,534 | | 2,468,534 | 9 |
| | | | 551,498 | 551,498 | 10 |
| 44,838 | | 1,123,037 | | 1,123,037 | 11 |
| 3,469 | | 68,602 | | 68,602 | 12 |
| 280 | | 8,477 | | 8,477 | 13 |
| | | 8,136,318 | | 8,136,318 | 14 |
| 0 | 0 | 0 | 0 | 0 | |
| 3,574,840 | 6,256,410 | 105,936,639 | 10,398,246 | 122,591,295 | |
| **3,574,840** | **6,256,410** | **105,936,639** | **10,398,246** | **122,591,295** | |

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

| MegaWatt Hours Sold (g) | REVENUE Demand Charges ($) (h) | Energy Charges ($) (i) | Other Charges ($) (j) | Total ($) (h+i+j) (k) | Line No. |
|---|---|---|---|---|---|
| | | | 998,098 | 998,098 | 1 |
| 2,600 | | 78,750 | | 78,750 | 2 |
| 20 | | 840 | | 840 | 3 |
| | | | | | 4 |
| | | | -634,950 | -634,950 | 5 |
| | | | -758,500 | -758,500 | 6 |
| | | | | | 7 |
| | | | | | 8 |
| | | | | | 9 |
| 175 | 6,256,410 | | | 6,256,410 | 10 |
| | | | | | 11 |
| | | | | | 12 |
| | | | | | 13 |
| | | | | | 14 |
| 0 | 0 | 0 | 0 | 0 | |
| 3,574,840 | 6,256,410 | 105,936,639 | 10,398,246 | 122,591,295 | |
| **3,574,840** | **6,256,410** | **105,936,639** | **10,398,246** | **122,591,295** | |

**Schedule Page: 310 Line No.: 9 Column: j**

Represents a true-up of a prior accrual with the California Independent System Operator.

**Schedule Page: 310 Line No.: 11 Column: j**

Represents sales of renewable energy credits to Calpine.

**Schedule Page: 310.1 Line No.: 5 Column: j**

Represents sales of renewable energy credits to City of Vernon.

**Schedule Page: 310.1 Line No.: 8 Column: j**

Represents sales of renewable energy credits to Commerce Energy.

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

Represents sales of renewable energy credits to Element Market.

**Schedule Page: 310.2 Line No.: 3 Column: j**

Represents sales of renewable energy credits to Exelon Generation Company.

**Schedule Page: 310.2 Line No.: 6 Column: j**

Represents sales of renewable energy credits to Just Energy Solutions.

**Schedule Page: 310.2 Line No.: 7 Column: j**

Represents the value of energy received by the PGE control area from Electric Service Suppliers in deficit of the ESS's actual load within the PGE control area.

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

Represents a true-up of a prior accrual with Los Angeles Department of Water and Power.

**Schedule Page: 310.2 Line No.: 11 Column: j**

Represents sales of renewable energy credits to Marin Clean Energy.

**Schedule Page: 310.3 Line No.: 5 Column: j**

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

**Schedule Page: 310.4 Line No.: 2 Column: j**

Represents sales of renewable energy credits to Shell Energy North America.

**Schedule Page: 310.4 Line No.: 4 Column: j**

Represents sales of renewable energy credits to Sonoma Clean Power Authority.

**Schedule Page: 310.4 Line No.: 10 Column: j**

Represents sales of renewable energy credits to The Energy Authority.

**Schedule Page: 310.4 Line No.: 14 Column: i**

Represents the net value of sale of 10 percent of PGE's Boardman Coal Plant to Turlock Irrigation District.

**Schedule Page: 310.5 Line No.: 1 Column: j**

Represents a true-up of a prior accrual with Turlock Boardman Revenue.

**Schedule Page: 310.5 Line No.: 5 Column: j**

Defer 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: 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.: 10 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.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

| Line No. | Account<br>(a) | Amount for Current Year<br>(b) | Amount for Previous Year<br>(c) |
|---|---|---|---|
| 1 | 1. POWER PRODUCTION EXPENSES | | |
| 2 | A. Steam Power Generation | | |
| 3 | Operation | | |
| 4 | (500) Operation Supervision and Engineering | 2,528,033 | 2,856,938 |
| 5 | (501) Fuel | 73,931,132 | 75,916,482 |
| 6 | (502) Steam Expenses | 6,803,509 | 6,831,410 |
| 7 | (503) Steam from Other Sources | | |
| 8 | (Less) (504) Steam Transferred-Cr. | | |
| 9 | (505) Electric Expenses | | |
| 10 | (506) Miscellaneous Steam Power Expenses | 9,085,127 | 8,121,397 |
| 11 | (507) Rents | 56,711 | 42,262 |
| 12 | (509) Allowances | | |
| 13 | TOTAL Operation (Enter Total of Lines 4 thru 12) | 92,404,512 | 93,768,489 |
| 14 | Maintenance | | |
| 15 | (510) Maintenance Supervision and Engineering | 798,060 | 950,845 |
| 16 | (511) Maintenance of Structures | 1,015,128 | 1,094,274 |
| 17 | (512) Maintenance of Boiler Plant | 7,174,077 | 7,497,261 |
| 18 | (513) Maintenance of Electric Plant | 13,592,332 | 12,383,171 |
| 19 | (514) Maintenance of Miscellaneous Steam Plant | 1,296,207 | 1,341,286 |
| 20 | TOTAL Maintenance (Enter Total of Lines 15 thru 19) | 23,875,804 | 23,266,837 |
| 21 | TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20) | 116,280,316 | 117,035,326 |
| 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 | 755,713 | 865,203 |
| 45 | (536) Water for Power | 581,506 | 568,105 |
| 46 | (537) Hydraulic Expenses | 6,695,183 | 6,908,505 |
| 47 | (538) Electric Expenses | 1,071,589 | 1,230,715 |
| 48 | (539) Miscellaneous Hydraulic Power Generation Expenses | 3,173,488 | 3,049,632 |
| 49 | (540) Rents | 701,021 | 672,782 |
| 50 | TOTAL Operation (Enter Total of Lines 44 thru 49) | 12,978,500 | 13,294,942 |
| 51 | C. Hydraulic Power Generation (Continued) | | |
| 52 | Maintenance | | |
| 53 | (541) Mainentance Supervision and Engineering | 1,079,970 | 796,022 |
| 54 | (542) Maintenance of Structures | -1,567 | 137,894 |
| 55 | (543) Maintenance of Reservoirs, Dams, and Waterways | 561,264 | 1,871,508 |
| 56 | (544) Maintenance of Electric Plant | 1,276,918 | 1,309,814 |
| 57 | (545) Maintenance of Miscellaneous Hydraulic Plant | 1,564,694 | 1,253,936 |
| 58 | TOTAL Maintenance (Enter Total of lines 53 thru 57) | 4,481,279 | 5,369,174 |
| 59 | TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58) | 17,459,779 | 18,664,116 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

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 | 3,425,489 | 3,820,585 |
| 63 | (547) Fuel | 206,350,881 | 218,907,039 |
| 64 | (548) Generation Expenses | 10,137,232 | 7,064,413 |
| 65 | (549) Miscellaneous Other Power Generation Expenses | 12,059,952 | 12,715,658 |
| 66 | (550) Rents | 1,253,870 | 1,135,286 |
| 67 | TOTAL Operation (Enter Total of lines 62 thru 66) | 233,227,424 | 243,642,981 |
| 68 | Maintenance | | |
| 69 | (551) Maintenance Supervision and Engineering | 887,267 | 725,649 |
| 70 | (552) Maintenance of Structures | 357,361 | 692,528 |
| 71 | (553) Maintenance of Generating and Electric Plant | 47,172,190 | 40,364,586 |
| 72 | (554) Maintenance of Miscellaneous Other Power Generation Plant | 1,120,428 | 1,017,793 |
| 73 | TOTAL Maintenance (Enter Total of lines 69 thru 72) | 49,537,246 | 42,800,556 |
| 74 | TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73) | 282,764,670 | 286,443,537 |
| 75 | E. Other Power Supply Expenses | | |
| 76 | (555) Purchased Power | 244,313,723 | 264,106,264 |
| 77 | (556) System Control and Load Dispatching | 142,347 | 52,886 |
| 78 | (557) Other Expenses | 17,993,369 | 19,074,719 |
| 79 | TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78) | 262,449,439 | 283,233,869 |
| 80 | TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79) | 678,954,204 | 705,376,848 |
| 81 | 2. TRANSMISSION EXPENSES | | |
| 82 | Operation | | |
| 83 | (560) Operation Supervision and Engineering | 5,307,982 | 4,856,873 |
| 84 | | | |
| 85 | (561.1) Load Dispatch-Reliability | 13,940 | 12,519 |
| 86 | (561.2) Load Dispatch-Monitor and Operate Transmission System | 629,769 | 587,601 |
| 87 | (561.3) Load Dispatch-Transmission Service and Scheduling | 1,205,851 | 1,204,546 |
| 88 | (561.4) Scheduling, System Control and Dispatch Services | | |
| 89 | (561.5) Reliability, Planning and Standards Development | 25,400 | 11,450 |
| 90 | (561.6) Transmission Service Studies | 20,728 | |
| 91 | (561.7) Generation Interconnection Studies | | 173 |
| 92 | (561.8) Reliability, Planning and Standards Development Services | | |
| 93 | (562) Station Expenses | 137,719 | 128,451 |
| 94 | (563) Overhead Lines Expenses | 101,597 | 24,083 |
| 95 | (564) Underground Lines Expenses | | |
| 96 | (565) Transmission of Electricity by Others | 85,194,317 | 76,819,291 |
| 97 | (566) Miscellaneous Transmission Expenses | 6,313,534 | 5,994,781 |
| 98 | (567) Rents | 2,496,378 | 2,603,243 |
| 99 | TOTAL Operation (Enter Total of lines 83 thru 98) | 101,447,215 | 92,243,011 |
| 100 | Maintenance | | |
| 101 | (568) Maintenance Supervision and Engineering | 31,935 | 42,953 |
| 102 | (569) Maintenance of Structures | | |
| 103 | (569.1) Maintenance of Computer Hardware | | |
| 104 | (569.2) Maintenance of Computer Software | 571,090 | 771,530 |
| 105 | (569.3) Maintenance of Communication Equipment | | |
| 106 | (569.4) Maintenance of Miscellaneous Regional Transmission Plant | | |
| 107 | (570) Maintenance of Station Equipment | 1,558,360 | 1,818,551 |
| 108 | (571) Maintenance of Overhead Lines | 671,082 | 488,486 |
| 109 | (572) Maintenance of Underground Lines | | |
| 110 | (573) Maintenance of Miscellaneous Transmission Plant | 2,087 | 123 |
| 111 | TOTAL Maintenance (Total of lines 101 thru 110) | 2,834,554 | 3,121,643 |
| 112 | TOTAL Transmission Expenses (Total of lines 99 and 111) | 104,281,769 | 95,364,654 |

| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

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<br>(a) | Amount for Current Year<br>(b) | Amount for Previous Year<br>(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 Expns (Total 123 and 130) | | |
| 132 | 4. DISTRIBUTION EXPENSES | | |
| 133 | Operation | | |
| 134 | (580) Operation Supervision and Engineering | 21,509,824 | 21,879,494 |
| 135 | (581) Load Dispatching | 1,677,843 | 1,827,184 |
| 136 | (582) Station Expenses | 1,033,545 | 1,149,199 |
| 137 | (583) Overhead Line Expenses | 2,481,905 | 3,101,422 |
| 138 | (584) Underground Line Expenses | 4,319,262 | 4,890,482 |
| 139 | (585) Street Lighting and Signal System Expenses | 574,742 | 745,908 |
| 140 | (586) Meter Expenses | 3,600,097 | 2,886,772 |
| 141 | (587) Customer Installations Expenses | 3,677,198 | 3,786,067 |
| 142 | (588) Miscellaneous Expenses | 8,826,946 | 7,769,194 |
| 143 | (589) Rents | 1,939,244 | 1,597,954 |
| 144 | TOTAL Operation (Enter Total of lines 134 thru 143) | 49,640,606 | 49,633,676 |
| 145 | Maintenance | | |
| 146 | (590) Maintenance Supervision and Engineering | 82,548 | 45,062 |
| 147 | (591) Maintenance of Structures | 142,377 | 131,768 |
| 148 | (592) Maintenance of Station Equipment | 4,904,078 | 4,434,226 |
| 149 | (593) Maintenance of Overhead Lines | 51,998,827 | 42,841,925 |
| 150 | (594) Maintenance of Underground Lines | 8,249,148 | 6,891,835 |
| 151 | (595) Maintenance of Line Transformers | 2,422,619 | 2,034,995 |
| 152 | (596) Maintenance of Street Lighting and Signal Systems | 793,545 | 1,071,417 |
| 153 | (597) Maintenance of Meters | 34,243 | 80,032 |
| 154 | (598) Maintenance of Miscellaneous Distribution Plant | 9,368,831 | 9,446,556 |
| 155 | TOTAL Maintenance (Total of lines 146 thru 154) | 77,996,216 | 66,977,816 |
| 156 | TOTAL Distribution Expenses (Total of lines 144 and 155) | 127,636,822 | 116,611,492 |
| 157 | 5. CUSTOMER ACCOUNTS EXPENSES | | |
| 158 | Operation | | |
| 159 | (901) Supervision | | |
| 160 | (902) Meter Reading Expenses | 533,423 | 673,600 |
| 161 | (903) Customer Records and Collection Expenses | 46,664,695 | 45,013,372 |
| 162 | (904) Uncollectible Accounts | 5,457,183 | 5,152,432 |
| 163 | (905) Miscellaneous Customer Accounts Expenses | 5,838,137 | 5,595,059 |
| 164 | TOTAL Customer Accounts Expenses (Total of lines 159 thru 163) | 58,493,438 | 56,434,463 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

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 | 14,167,443 | 12,176,505 |
| 169 | (909) Informational and Instructional Expenses | 1,528,329 | 2,015,784 |
| 170 | (910) Miscellaneous Customer Service and Informational Expenses | | |
| 171 | TOTAL Customer Service and Information Expenses (Total 167 thru 170) | 15,695,772 | 14,192,289 |
| 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 | 70,004,394 | 61,816,665 |
| 182 | (921) Office Supplies and Expenses | 21,720,812 | 20,759,207 |
| 183 | (Less) (922) Administrative Expenses Transferred-Credit | 10,623,570 | 10,284,696 |
| 184 | (923) Outside Services Employed | 15,545,665 | 11,902,472 |
| 185 | (924) Property Insurance | 5,472,190 | 5,444,257 |
| 186 | (925) Injuries and Damages | 5,278,208 | 4,422,890 |
| 187 | (926) Employee Pensions and Benefits | 56,301,824 | 57,374,107 |
| 188 | (927) Franchise Requirements | | |
| 189 | (928) Regulatory Commission Expenses | 9,542,465 | 7,708,208 |
| 190 | (929) (Less) Duplicate Charges-Cr. | 2,309,778 | 2,254,487 |
| 191 | (930.1) General Advertising Expenses | 719,666 | 538,053 |
| 192 | (930.2) Miscellaneous General Expenses | 11,484,824 | 11,461,517 |
| 193 | (931) Rents | 5,090,394 | 4,875,592 |
| 194 | TOTAL Operation (Enter Total of lines 181 thru 193) | 188,227,094 | 173,763,785 |
| 195 | Maintenance | | |
| 196 | (935) Maintenance of General Plant | 2,535,803 | 2,706,940 |
| 197 | TOTAL Administrative & General Expenses (Total of lines 194 and 196) | 190,762,897 | 176,470,725 |
| 198 | TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197) | 1,175,824,902 | 1,164,450,471 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## 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) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | Avangrid Renewables (was Iberdrola) | SF | PGE-11 | NA | NA | NA |
| 2 | Avangrid Renewables (was Iberdrola) | LU | PGE-11 | NA | NA | NA |
| 3 | Avista Corp. (was WWP) | SF | WSPP-1 | NA | NA | NA |
| 4 | Avista Corp. (was Spokane Energy, LLC) | EX | PGE-82 | NA | NA | NA |
| 5 | BC Hydro | SF | WSPP-1 | NA | NA | NA |
| 6 | Baldock Solar | LU | Baldock | NA | NA | NA |
| 7 | Bellevue Solar | LU | Bellevue | NA | NA | NA |
| 8 | Bonneville Power Administration | SF | WSPP-1 | NA | NA | NA |
| 9 | Brookfield Energy Marketing | SF | WSPP-1 | NA | NA | NA |
| 10 | BP Energy Company | SF | PGE-11 | NA | NA | NA |
| 11 | Burbank, City of | SF | WSPP-1 | NA | NA | NA |
| 12 | California Independent System Operator | SF | CAISO | NA | NA | NA |
| 13 | Calpine Energy Services | SF | PGE-11 | NA | NA | NA |
| 14 | Cargill Power Markets, LLC | SF | WSPP-1 | NA | NA | NA |
| | Total | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## 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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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.

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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) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | Chelan County, PUD No. 1, Washington | SF | WSPP-1 | NA | NA | NA |
| 2 | Citigroup Energy | SF | WSPP-1 | NA | NA | NA |
| 3 | Clatskanie County PUD | SF | WSPP-1 | NA | NA | NA |
| 4 | ConocoPhillips | SF | WSPP-1 | NA | NA | NA |
| 5 | Conduit 3 Hydro | LU | 201.00 | NA | NA | NA |
| 6 | Covanta Marion | LU | QF83-118 | NA | NA | NA |
| 7 | Douglas County, PUD No. 1, Washington | LU | Wells | NA | NA | NA |
| 8 | Douglas County, PUD No. 1, Washington | LF | Wells | NA | NA | NA |
| 9 | Douglas County, PUD No. 1, Washington | SF | WSPP-1 | NA | NA | NA |
| 10 | EDF Trading North America, LLC | SF | WSPP-1 | NA | NA | NA |
| 11 | Enmax | SF | PGE-11 | NA | NA | NA |
| 12 | Energy Keepers, Inc. - ENKP | SF | WSPP-1 | NA | NA | NA |
| 13 | ESI Vansycle Partners, LP | LU | WSPP-1 | NA | NA | NA |
| 14 | Eugene Water & Electric Board | LU | WSPP-1 | 10 | 10 | 10 |
| | Total | | | | | |

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

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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) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | Eugene Water & Electric Board | LU | ER94-717 | NA | NA | NA |
| 2 | Eugene Water & Electric Board | SF | WSPP-1 | NA | NA | NA |
| 3 | Exelon Generation Co. | SF | WSPP-1 | NA | NA | NA |
| 4 | Forest Glen Oaks Biomass | LU | FGO | NA | NA | NA |
| 5 | Gridforce Energy Management | SF | WSPP-1 | NA | NA | NA |
| 6 | Glendale, City of | SF | WSPP-1 | NA | NA | NA |
| 7 | Grant County, PUD No. 2, Washington | LU | Wanapum | NA | NA | NA |
| 8 | Grant County, PUD No. 2, Washington | LU | Priest Rapids | NA | NA | NA |
| 9 | Grant County, PUD No. 2, Washington | SF | WSPP-1 | NA | NA | NA |
| 10 | Avangrid Renewables (was Iberdrola) | LU | PGE-11 | 100 | 100 | 100 |
| 11 | Idaho Falls, City of | SF | WSPP-1 | NA | NA | NA |
| 12 | Idaho Power Company | SF | WSPP-1 | NA | NA | NA |
| 13 | JC Biomethane | LU | JCBIO | NA | NA | NA |
| 14 | Load Balance Energy | OS | OATT | NA | NA | NA |
| | Total | | | | | |

## 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) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | Macquarie Cook Power | SF | WSPP-1 | NA | NA | NA |
| 2 | Morgan Stanley Capital Group | SF | PGE-11 | NA | NA | NA |
| 3 | NaturEner Power Watch, LLC | SF | WSPP-1 | NA | NA | NA |
| 4 | NextEra Energy Power Marketing, LLC | SF | WSPP-1 | NA | NA | NA |
| 5 | Northern Wasco PUD Hydro | LU | NWASCO | NA | NA | NA |
| 6 | NorthWestern Corporation | SF | WSPP-1 | NA | NA | NA |
| 7 | Okanogan County PUD, Washington | SF | WSPP-1 | NA | NA | NA |
| 8 | Outback Solar | LU | Outback | NA | NA | NA |
| 9 | Pacific NW Generating Company | SF | WSPP-1 | NA | NA | NA |
| 10 | PacifiCorp | RQ | PP&L 147 | NA | NA | NA |
| 11 | PacifiCorp | SF | PGE-11 | NA | NA | NA |
| 12 | PaTu Wind | LU | WSPP-1 | NA | NA | NA |
| 13 | Portland, City of | LU | #2821 | NA | NA | NA |
| 14 | Powerex | SF | PGE-11 | NA | NA | NA |
| | Total | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

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) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | Public Utility District No. 1 of Clark | SF | WSPP-1 | NA | NA | NA |
| 2 | Puget Sound Energy | SF | WSPP-1 | NA | NA | NA |
| 3 | Roseville, City of | SF | WSPP-1 | NA | NA | NA |
| 4 | Sacramento Municipal Utility District | SF | WSPP-1 | NA | NA | NA |
| 5 | Seattle City Light | SF | WSPP-1 | NA | NA | NA |
| 6 | Shell Energy | SF | WSPP-1 | NA | NA | NA |
| 7 | Snohomish County, PUD No. 1, Washingtn | SF | WSPP-1 | NA | NA | NA |
| 8 | Southern California Edison | SF | PGE-11 | NA | NA | NA |
| 9 | Steel Bridge | LU | 201 | NA | NA | NA |
| 10 | Tacoma, City of | SF | WSPP-1 | NA | NA | NA |
| 11 | Talen Energy | SF | PGE-11 | NA | NA | NA |
| 12 | Tenaska | SF | WSPP-1 | NA | NA | NA |
| 13 | The Energy Authority | SF | WSPP-1 | NA | NA | NA |
| 14 | TransAlta Energy Marketing | SF | PGE-11 | NA | NA | NA |
| | Total | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## 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) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | TransCanada Energy Marketing | SF | WSPP-1 | NA | NA | NA |
| 2 | Turlock Irrigation District | SF | WSPP-1 | NA | NA | NA |
| 3 | Vitol Inc | SF | WSPP-1 | NA | NA | NA |
| 4 | Warm Springs Power Enterprises | LU | WSPP-1 | NA | NA | NA |
| 5 | WAPA - Upper Great Plains Region | SF | WSPP-1 | NA | NA | NA |
| 6 | Yamhill Solar | LU | Yamhill | NA | NA | NA |
| 7 | Lake Oswego Corporation | LU | 201 | NA | NA | NA |
| 8 | Country Village Estates | OS | 201 | NA | NA | NA |
| 9 | Domaine Drouhin | OS | 201 | NA | NA | NA |
| 10 | Minikahada Hydropower Co | OS | 201 | NA | NA | NA |
| 11 | Starbucks Properties | OS | 201 | NA | NA | NA |
| 12 | SunWay LLC | LU | 201 | NA | NA | NA |
| 13 | Solar Payment Option | OS | 215-217 | NA | NA | NA |
| 14 | Tualatin Valley Water Dist | OS | 201 | NA | NA | NA |
| | Total | | | | | |

| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

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) | Actual Demand (MW) Average Monthly CP Demand (f) |
|---|---|---|---|---|---|---|
| 1 | Oregon Heat | OS | 203 | NA | NA | NA |
| 2 | Load Curtailment Program | | | NA | NA | NA |
| 3 | Margin on Electric Financials | | | NA | NA | NA |
| 4 | Reserve Trading Credit Risk | | | NA | NA | NA |
| 5 | Green Power | | | NA | NA | NA |
| 6 | REC Retirement Expense | | | NA | NA | NA |
| 7 | Carbon Allowance Expense | | | NA | NA | NA |
| 8 | | | | | | |
| 9 | Non-cash exchanges | | | | | |
| 10 | Energy Storage Expense | | | | | |
| 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 monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. 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) | |
| 261,576 | | | | 6,371,185 | | 6,371,185 | 1 |
| 174,733 | | | | 9,907,435 | | 9,907,435 | 2 |
| 61,331 | | | | 3,582,013 | | 3,582,013 | 3 |
| | -1,350 | | | | | | 4 |
| 72 | | | | 2,082 | | 2,082 | 5 |
| 1,875 | | | | | | | 6 |
| 1,671 | | | | 175,477 | | 175,477 | 7 |
| 1,361,625 | | | | 21,379,451 | | 21,379,451 | 8 |
| 2,400 | | | | 54,000 | | 54,000 | 9 |
| 24,840 | | | | 374,268 | | 374,268 | 10 |
| 30 | | | | 450 | | 450 | 11 |
| 186,092 | | | | 7,374,012 | | 7,374,012 | 12 |
| 256,018 | | | | 6,177,372 | | 6,177,372 | 13 |
| 4,000 | | | | 116,592 | | 116,592 | 14 |
| 9,487,631 | -1,350 | | 2,529,000 | 211,864,841 | 29,919,882 | 244,313,723 | |

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 monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. 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) | |
| 326,766 | | | | 7,677,238 | | 7,677,238 | 1 |
| 78,400 | | | | 1,141,704 | | 1,141,704 | 2 |
| 1,767 | | | | 40,792 | | 40,792 | 3 |
| 3,200 | | | | 98,800 | | 98,800 | 4 |
| 257 | | | | 15,110 | | 15,110 | 5 |
| 80,942 | | | | 2,020,260 | | 2,020,260 | 6 |
| 799,251 | | | | 11,013,074 | | 11,013,074 | 7 |
| 164,602 | | | | 4,122,232 | | 4,122,232 | 8 |
| 45,626 | | | | 904,421 | | 904,421 | 9 |
| 46,570 | | | | 837,325 | | 837,325 | 10 |
| 8,830 | | | | 244,903 | | 244,903 | 11 |
| 2,640 | | | | 30,856 | | 30,856 | 12 |
| 64,164 | | | | 3,851,402 | | 3,851,402 | 13 |
| | | | 84,000 | | | 84,000 | 14 |
| 9,487,631 | -1,350 | | 2,529,000 | 211,864,841 | 29,919,882 | 244,313,723 | |

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 monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. 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) | |
| 866 | | | | | | | 1 |
| 68,572 | | | | 1,399,290 | | 1,399,290 | 2 |
| 65,679 | | | | 1,280,216 | | 1,280,216 | 3 |
| 477 | | | | 44,259 | | 44,259 | 4 |
| 26 | | | | 696 | | 696 | 5 |
| 292 | | | | 4,300 | | 4,300 | 6 |
| 363,152 | | | | | | | 7 |
| 390,077 | | | | 15,699,808 | | 15,699,808 | 8 |
| 65 | | | | 2,041 | | 2,041 | 9 |
| | | | 2,445,000 | | | 2,445,000 | 10 |
| 555 | | | | | | | 11 |
| 21,512 | | | | 324,598 | | 324,598 | 12 |
| 9,716 | | | | 604,512 | | 604,512 | 13 |
| 111,971 | | | | 1,412,148 | | 1,412,148 | 14 |
| 9,487,631 | -1,350 | | 2,529,000 | 211,864,841 | 29,919,882 | 244,313,723 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

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 monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. 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) | |
| 71,200 | | | | 1,691,958 | | 1,691,958 | 1 |
| 64,374 | | | | 1,405,344 | | 1,405,344 | 2 |
| 1 | | | | 26 | | 26 | 3 |
| 972 | | | | 8,870 | | 8,870 | 4 |
| 29,654 | | | | 601,381 | | 601,381 | 5 |
| 7,650 | | | | 210,071 | | 210,071 | 6 |
| 33,685 | | | | 416,382 | | 416,382 | 7 |
| 10,823 | | | | 972,540 | | 972,540 | 8 |
| 47,545 | | | | 3,334,797 | | 3,334,797 | 9 |
| 4,640 | | | | 489,656 | | 489,656 | 10 |
| 48,483 | | | | 1,176,208 | | 1,176,208 | 11 |
| 25,176 | | | | 1,862,303 | | 1,862,303 | 12 |
| 95,897 | | | | 1,870,647 | | 1,870,647 | 13 |
| 228,354 | | | | 7,372,632 | | 7,372,632 | 14 |
| 9,487,631 | -1,350 | | 2,529,000 | 211,864,841 | 29,919,882 | 244,313,723 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

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 monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. 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) | |
| 4,514 | | | | 61,546 | | 61,546 | 1 |
| 162,326 | | | | 4,090,431 | | 4,090,431 | 2 |
| 84 | | | | 127 | | 127 | 3 |
| 1,303 | | | | 25,860 | | 25,860 | 4 |
| 209,986 | | | | 4,937,279 | | 4,937,279 | 5 |
| 2,062,730 | | | | 42,573,829 | | 42,573,829 | 6 |
| 67,005 | | | | 1,102,343 | | 1,102,343 | 7 |
| 90 | | | | 450 | | 450 | 8 |
| 3,332 | | | | 252,583 | | 252,583 | 9 |
| 71,723 | | | | 2,269,952 | | 2,269,952 | 10 |
| 9,110 | | | | 245,220 | | 245,220 | 11 |
| 2,040 | | | | 39,114 | | 39,114 | 12 |
| 263,251 | | | | 2,979,149 | | 2,979,149 | 13 |
| 155,710 | | | | 4,488,799 | | 4,488,799 | 14 |
| 9,487,631 | -1,350 | | 2,529,000 | 211,864,841 | 29,919,882 | 244,313,723 | |

| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

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 monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. 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) | |
| 5,842 | | | | 165,776 | | 165,776 | 1 |
| 15,860 | | | | 170,102 | | 170,102 | 2 |
| 210,200 | | | | 3,103,754 | | 3,103,754 | 3 |
| 564,060 | | | | 15,000,178 | | 15,000,178 | 4 |
| | | | | 48 | | 48 | 5 |
| 969 | | | | 105,577 | | 105,577 | 6 |
| 317 | | | | 24,601 | | 24,601 | 7 |
| 46 | | | | 1,203 | | 1,203 | 8 |
| 35 | | | | 5,882 | | 5,882 | 9 |
| 284 | | | | 17,556 | | 17,556 | 10 |
| 30 | | | | 2,272 | | 2,272 | 11 |
| 2,081 | | | | 28 | | 28 | 12 |
| 12,176 | | | | 491,029 | | 491,029 | 13 |
| 217 | | | | 13,016 | | 13,016 | 14 |
| 9,487,631 | -1,350 | | 2,529,000 | 211,864,841 | 29,919,882 | 244,313,723 | |

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 monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. 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) | |
| 1,618 | | | | | 38,365 | 38,365 | 1 |
| | | | | | 960,869 | 960,869 | 2 |
| | | | | | 16,163,348 | 16,163,348 | 3 |
| | | | | | 76,263 | 76,263 | 4 |
| | | | | | 11,306,396 | 11,306,396 | 5 |
| | | | | | 1,157,591 | 1,157,591 | 6 |
| | | | | | 396,492 | 396,492 | 7 |
| | | | | | | | 8 |
| | | | | | -179,442 | -179,442 | 9 |
| | | | | | | | 10 |
| | | | | | | | 11 |
| | | | | | | | 12 |
| | | | | | | | 13 |
| | | | | | | | 14 |
| 9,487,631 | -1,350 | | 2,529,000 | 211,864,841 | 29,919,882 | 244,313,723 | |

***Schedule Page: 326.1 Line No.: 8 Column: b***

The Douglas County contract expires on 8/31/18.

***Schedule Page: 326.2 Line No.: 1 Column: g***

Represents net of energy generated at EWEB's Stone Creek Facility within PGE's control area and energy delivered to EWEB.

***Schedule Page: 326.2 Line No.: 14 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: 326.5 Line No.: 8 Column: b***

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

***Schedule Page: 326.5 Line No.: 9 Column: b***

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

***Schedule Page: 326.5 Line No.: 10 Column: b***

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

***Schedule Page: 326.5 Line No.: 11 Column: b***

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

***Schedule Page: 326.5 Line No.: 13 Column: b***

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

***Schedule Page: 326.5 Line No.: 14 Column: b***

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

***Schedule Page: 326.6 Line No.: 1 Column: b***

In accordance with Schedule 203 tariff any excess credits will be transferred to Low Income Assistance Program.

***Schedule Page: 326.6 Line No.: 2 Column: l***

Power purchased under Load Curtailment Program.

***Schedule Page: 326.6 Line No.: 3 Column: l***

Margin on electric financial transactions.

***Schedule Page: 326.6 Line No.: 4 Column: l***

Reserve for trading credit risk.

***Schedule Page: 326.6 Line No.: 5 Column: l***

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: 326.6 Line No.: 6 Column: l***

Expense of annual REC retirement to meet RPS compliance.

***Schedule Page: 326.6 Line No.: 7 Column: l***

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

***Schedule Page: 326.6 Line No.: 10 Column: a***

There are no costs recorded in Account 555.1, Power Purchased for Storage, as the Company did not purchase power for storage purposes during the year.

| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

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

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

| 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 Classifi-cation (d) |
|---|---|---|---|---|
| 1 | 3 Phases Renewables LLC | Bonneville Power Administration | Portland General Electric | OS |
| 2 | Avangrid Renewables, LLC | Bonneville Power Administration | Bonneville Power Administration | SFP |
| 3 | Avangrid Renewables, LLC | Bonneville Power Administration | Bonneville Power Administration | NF |
| 4 | Avangrid Renewables, LLC | CAISO | Bonneville Power Administration | NF |
| 5 | Avangrid Renewables, LLC | Bonneville Power Administration | Portland General Electric | OS |
| 6 | Avista Corp. Washington Water Power | Bonneville Power Administration | Balancing Authority of Northern C | LFP |
| 7 | Avista Corp. Washington Water Power | Bonneville Power Administration | CAISO | LFP |
| 8 | Avista Corp. Washington Water Power | Balancing Authority of Northern C | Bonneville Power Administration | NF |
| 9 | Avista Corp. Washington Water Power | CAISO | Bonneville Power Administration | OS |
| 10 | Avista Corp. Washington Water Power | CAISO | Bonneville Power Administration | NF |
| 11 | Avista Corp. Washington Water Power | Bonneville Power Administration | CAISO | NF |
| 12 | Bonneville Power Administration | Bonneville Power Administration | CAISO | NF |
| 13 | Bonneville Power Administration | Bonneville Power Administration | Portland General Electric | FNO |
| 14 | Bonneville Power Administration | Bonneville Power Administration | Western Oregon Electric Coop | OLF |
| 15 | Bonneville Power Administration | Bonneville Power Administration | Other TVI Pumps | OLF |
| 16 | Bonneville Power Administration | Bonneville Power Administration | Canby People's Utility District | OLF |
| 17 | Bonneville Power Administration | Bonneville Power Administration | Columbia River PUD | OLF |
| 18 | Brookfield Energy Marketing | Bonneville Power Administration | Balancing Authority of Northern C | SFP |
| 19 | Brookfield Energy Marketing | Bonneville Power Administration | CAISO | SFP |
| 20 | Brookfield Energy Marketing | Bonneville Power Administration | CAISO | NF |
| 21 | Calpine Energy Services | Bonneville Power Administration | Portland General Electric | OS |
| 22 | Canadian Wood Products - Montreal Inc. | Bonneville Power Administration | CAISO | NF |
| 23 | Exelon Generation Company LLC | Bonneville Power Administration | Balancing Authority of Northern C | LFP |
| 24 | Exelon Generation Company LLC | Bonneville Power Administration | Portland General Electric | LFP |
| 25 | Exelon Generation Company LLC | Bonneville Power Administration | CAISO | LFP |
| 26 | Exelon Generation Company LLC | Bonneville Power Administration | CAISO | NF |
| 27 | Exelon Generation Company LLC | Bonneville Power Administration | CAISO | NF |
| 28 | Exelon Generation Company LLC | Bonneville Power Administration | Portland General Electric | OS |
| 29 | Macquarie Energy LLC | CAISO | Bonneville Power Administration | SFP |
| 30 | Macquarie Energy LLC | CAISO | Bonneville Power Administration | NF |
| 31 | Macquarie Energy LLC | Bonneville Power Administration | CAISO | NF |
| 32 | Morgan Stanley Capital Group Inc. | Bonneville Power Administration | Balancing Authority of Northern C | LFP |
| 33 | Morgan Stanley Capital Group Inc. | Bonneville Power Administration | Balancing Authority of Northern C | NF |
| 34 | Morgan Stanley Capital Group Inc. | Bonneville Power Administration | CAISO | LFP |
| | **TOTAL** | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

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

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

| 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 Classifi-cation (d) |
|---|---|---|---|---|
| 1 | Morgan Stanley Capital Group Inc. | CAISO | Bonneville Power Administration | NF |
| 2 | Morgan Stanley Capital Group Inc. | Bonneville Power Administration | CAISO | NF |
| 3 | Pacificorp | Bonneville Power Administration | Portland General Electric | OLF |
| 4 | Pacificorp | Bonneville Power Administration | Portland General Electric | LFP |
| 5 | Powerex Corp. | Bonneville Power Administration | Balancing Authority of Northern C | LFP |
| 6 | Powerex Corp. | Bonneville Power Administration | Balancing Authority of Northern C | NF |
| 7 | Powerex Corp. | Bonneville Power Administration | Portland General Electric | LFP |
| 8 | Powerex Corp. | Bonneville Power Administration | CAISO | LFP |
| 9 | Powerex Corp. | Bonneville Power Administration | CAISO | NF |
| 10 | PUD No. 1 of Cowlitz County | RESALE to The Energy Authority | | LFP |
| 11 | PUD No. 1 of Franklin County | RESALE to The Energy Authority | | LFP |
| 12 | PUD No. 1 of Klickitat County | RESALE to The Energy Authority | | LFP |
| 13 | PUD No. 1 of Lewis County | RESALE to The Energy Authority | | LFP |
| 14 | Puget Sound Energy Marketing | CAISO | Bonneville Power Administration | SFP |
| 15 | Puget Sound Energy | Bonneville Power Administration | Bonneville Power Administration | NF |
| 16 | Puget Sound Energy Marketing | CAISO | Bonneville Power Administration | NF |
| 17 | Sacramento Municipal Utility Dist. | Bonneville Power Administration | Balancing Authority of Northern C | NF |
| 18 | Seattle City Light Marketing | Bonneville Power Administration | Balancing Authority of Northern C | NF |
| 19 | Seattle City Light Marketing | Bonneville Power Administration | CAISO | NF |
| 20 | Shell Energy North America (US), L.P. | Bonneville Power Administration | Balancing Authority of Northern C | LFP |
| 21 | Shell Energy North America (US), L.P. | Bonneville Power Administration | Balancing Authority of Northern C | NF |
| 22 | Shell Energy North America (US), L.P. | Balancing Authority of Northern C | Bonneville Power Administration | NF |
| 23 | Shell Energy North America (US), L.P. | CAISO | Bonneville Power Administration | NF |
| 24 | Shell Energy North America (US), L.P. | CAISO | Bonneville Power Administration | OS |
| 25 | Shell Energy North America (US), L.P. | Bonneville Power Administration | California Independent System Ope | LFP |
| 26 | Shell Energy North America (US), L.P. | Bonneville Power Administration | California Independent System Ope | NF |
| 27 | Shell Energy North America (US), L.P. | Bonneville Power Administration | Portland General Electric | OS |
| 28 | Tacoma Power | Bonneville Power Administration | CAISO | SFP |
| 29 | The Energy Authority | Bonneville Power Administration | Portland General Electric | LFP |
| 30 | The Energy Authority | Bonneville Power Administration | Balancing Authority of Northern C | LFP |
| 31 | The Energy Authority | Bonneville Power Administration | Balancing Authority of Northern C | NF |
| 32 | The Energy Authority | Balancing Authority of Northern C | Bonneville Power Administration | NF |
| 33 | The Energy Authority | Balancing Authority of Northern C | Bonneville Power Administration | OS |
| 34 | The Energy Authority | CAISO | Bonneville Power Administration | 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 Classifi-cation (d) |
|---|---|---|---|---|
| 1 | The Energy Authority | CAISO | Bonneville Power Administration | OS |
| 2 | The Energy Authority | Bonneville Power Administration | CAISO | LFP |
| 3 | The Energy Authority | Bonneville Power Administration | CAISO | NF |
| 4 | TransAlta Energy Marketing U.S. Inc. | CAISO | Bonneville Power Administration | NF |
| 5 | TransAlta Energy Marketing U.S. Inc. | Bonneville Power Administration | CAISO | NF |
| 6 | Turlock Irrigation District | Bonneville Power Administration | Balancing Authority of Northern C | NF |
| 7 | Accrual | | | AD |
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| | **TOTAL** | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered 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 (Subsatation or Other Designation) (f) | Point of Delivery (Substation or Other Designation) (g) | Billing Demand (MW) (h) | TRANSFER OF ENERGY MegaWatt Hours Received (i) | TRANSFER OF ENERGY MegaWatt Hours Delivered (j) | Line No. |
|---|---|---|---|---|---|---|
| 8 | BPAT.PGE | PGE | 31 | 3,864 | 217 | 1 |
| 7 | KFallsGen | JohnDay | | 6,950 | 6,950 | 2 |
| 8 | KFallsGen | JohnDay | | 75 | 75 | 3 |
| 8 | Malin500 | JohnDay | | 374 | 374 | 4 |
| 8 | BPAT.PGE | PGE | 1,002 | 103,686 | 98,644 | 5 |
| 7 | JohnDay | CaptainJack | | 25 | 25 | 6 |
| 7 | JohnDay | Malin500 | | 442,299 | 442,299 | 7 |
| 8 | CaptainJack | JohnDay | | 150 | 150 | 8 |
| 8 | Malin500 | JohnDay | | 5,089 | 5,089 | 9 |
| 8 | Malin500 | JohnDay | | 2,522 | 2,522 | 10 |
| 8 | JohnDay | Malin500 | | 168,074 | 168,074 | 11 |
| 8 | JohnDay | Malin500 | | 27 | 27 | 12 |
| 7 | BPAT.PGE | PGE | 93 | 98,198 | 96,326 | 13 |
| 72 | JohnDay | Various Subs | | 14,963 | 14,149 | 14 |
| 72 | JohnDay | Various Subs | | 7,162 | 6,642 | 15 |
| 72 | JohnDay | Various Subs | | 175,468 | 166,205 | 16 |
| 72 | JohnDay | Various Subs | | 220,679 | 208,481 | 17 |
| 7 | JohnDay | CaptainJack | | 20,367 | 20,367 | 18 |
| 7 | JohnDay | Malin500 | | 213,747 | 213,747 | 19 |
| 8 | JohnDay | Malin500 | | 25 | 25 | 20 |
| 8 | BPAT.PGE | PGE | 2,510 | 1,596,776 | 1,549,284 | 21 |
| 8 | JohnDay | Malin500 | | 412 | 412 | 22 |
| 7 | JohnDay | CaptainJack | | 11,611 | 11,611 | 23 |
| 7 | JohnDay | COBH | | 160 | 160 | 24 |
| 7 | JohnDay | Malin500 | | 59,031 | 59,031 | 25 |
| 8 | JohnDay | Malin500 | | 721 | 721 | 26 |
| 8 | JohnDay | Malin500 | | 78 | 78 | 27 |
| 8 | BPAT.PGE | PGE | 394 | 322,502 | 332,882 | 28 |
| 7 | Malin500 | JohnDay | | 800 | 800 | 29 |
| 8 | Malin500 | JohnDay | | 75 | 75 | 30 |
| 8 | JohnDay | Malin500 | | 131 | 131 | 31 |
| 7 | JohnDay | CaptainJack | | 67,664 | 67,664 | 32 |
| 8 | JohnDay | CaptainJack | | 792 | 792 | 33 |
| 7 | JohnDay | Malin500 | | 411 | 411 | 34 |
| | | | **4,149** | **6,384,452** | **6,313,307** | |

| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered 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 (Subsatation or Other Designation) (f) | Point of Delivery (Substation or Other Designation) (g) | Billing Demand (MW) (h) | TRANSFER OF ENERGY MegaWatt Hours Received (i) | TRANSFER OF ENERGY MegaWatt Hours Delivered (j) | Line No. |
|---|---|---|---|---|---|---|
| 8 | Malin500 | JohnDay | | 687 | 687 | 1 |
| 8 | JohnDay | Malin500 | | 771 | 771 | 2 |
| Exch | JohnDay | Various Subs | | -3,401 | 3,413 | 3 |
| 7 | RoundButte | Redmond | | | | 4 |
| 7 | JohnDay | CaptainJack | | 276,290 | 276,290 | 5 |
| 8 | JohnDay | CaptainJack | | 2,296 | 2,296 | 6 |
| 7 | JohnDay | COBH | | 375 | 375 | 7 |
| 7 | JohnDay | Malin500 | | 1,177,604 | 1,177,604 | 8 |
| 8 | JohnDay | Malin500 | | 2,401 | 2,401 | 9 |
| 7 | 0 | 0 | | | | 10 |
| 7 | 0 | 0 | | | | 11 |
| 7 | 0 | 0 | | | | 12 |
| 7 | 0 | 0 | | | | 13 |
| 7 | Malin500 | JohnDay | | 1,225 | 1,225 | 14 |
| 8 | KFallsGen | JohnDay | | 235 | 235 | 15 |
| 8 | Malin500 | JohnDay | | 6,828 | 6,828 | 16 |
| 8 | JohnDay | CaptainJack | | 225 | 225 | 17 |
| 8 | JohnDay | CaptainJack | | 170 | 170 | 18 |
| 8 | JohnDay | Malin500 | | 156 | 156 | 19 |
| 7 | JohnDay | CaptainJack | | 224,768 | 224,768 | 20 |
| 8 | JohnDay | CaptainJack | | 6,940 | 6,940 | 21 |
| 8 | CaptainJack | JohnDay | | 35 | 35 | 22 |
| 8 | Malin500 | JohnDay | | 2,757 | 2,757 | 23 |
| 8 | Malin500 | JohnDay | | 360 | 360 | 24 |
| 7 | JohnDay | Malin500 | | 955,762 | 955,762 | 25 |
| 8 | JohnDay | Malin500 | | 13,836 | 13,836 | 26 |
| 8 | BPAT.PGE | PGE | 119 | 78,672 | 71,181 | 27 |
| 7 | JohnDay | Malin500 | | 10,557 | 10,557 | 28 |
| 7 | JohnDay | COBH | | 1,968 | 1,968 | 29 |
| 7 | JohnDay | CaptainJack | | 12,291 | 12,291 | 30 |
| 8 | JohnDay | CaptainJack | | 820 | 820 | 31 |
| 8 | CaptainJack | JohnDay | | 1,387 | 1,387 | 32 |
| 8 | CaptainJack | JohnDay | | 1,072 | 1,072 | 33 |
| 8 | Malin500 | JohnDay | | 5,869 | 5,869 | 34 |
| | | | **4,149** | **6,384,452** | **6,313,307** | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered 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 (Subsatation or Other Designation) (f) | Point of Delivery (Substation or Other Designation) (g) | Billing Demand (MW) (h) | TRANSFER OF ENERGY MegaWatt Hours Received (i) | TRANSFER OF ENERGY MegaWatt Hours Delivered (j) | Line No. |
|---|---|---|---|---|---|---|
| 8 | Malin500 | JohnDay | | 1,486 | 1,486 | 1 |
| 7 | JohnDay | Malin500 | | 41,473 | 41,473 | 2 |
| 8 | JohnDay | Malin500 | | 3,731 | 3,731 | 3 |
| 8 | Malin500 | JohnDay | | 2,673 | 2,673 | 4 |
| 8 | JohnDay | Malin500 | | 7,003 | 7,003 | 5 |
| 8 | JohnDay | CaptainJack | | 222 | 222 | 6 |
| | | | | | | 7 |
| | | | | | | 8 |
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| | | | **4,149** | **6,384,452** | **6,313,307** | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered 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. |
|---|---|---|---|---|
| 1,796 | 1,466 | | 3,262 | 1 |
| | 10,205 | | 10,205 | 2 |
| | 95 | | 95 | 3 |
| | 610 | | 610 | 4 |
| 154,547 | | | 154,547 | 5 |
| | 160,747 | | 160,747 | 6 |
| | 481,294 | | 481,294 | 7 |
| | 1 | | 1 | 8 |
| | 948 | | 948 | 9 |
| | 4,676 | | 4,676 | 10 |
| | 1,894 | | 1,894 | 11 |
| | 21 | | 21 | 12 |
| 108,880 | | | 108,880 | 13 |
| 101,397 | | | 101,397 | 14 |
| 29,935 | | | 29,935 | 15 |
| 364,554 | | | 364,554 | 16 |
| 53,473 | | | 53,473 | 17 |
| | 84,668 | | 84,668 | 18 |
| | 880,583 | | 880,583 | 19 |
| | 18 | | 18 | 20 |
| 1,814,863 | | | 1,814,863 | 21 |
| | 824 | | 824 | 22 |
| | 4,386 | | 4,386 | 23 |
| | 134 | | 134 | 24 |
| | 44,079 | | 44,079 | 25 |
| | 767 | | 767 | 26 |
| | 97 | | 97 | 27 |
| 416,671 | | | 416,671 | 28 |
| | 4,082 | | 4,082 | 29 |
| | 96 | | 96 | 30 |
| | 166 | | 166 | 31 |
| | 63,964 | | 63,964 | 32 |
| | 1,310 | | 1,310 | 33 |
| | 335 | | 335 | 34 |
| **3,139,911** | **4,487,135** | **884,389** | **8,511,435** | |

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered 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. |
|---|---|---|---|---|
| | 803 | | 803 | 1 |
| | 1,269 | | 1,269 | 2 |
| | | 247,346 | 247,346 | 3 |
| | 62,018 | | 62,018 | 4 |
| | 321,003 | | 321,003 | 5 |
| | 11,490 | | 11,490 | 6 |
| | 347 | | 347 | 7 |
| | 1,491,879 | | 1,491,879 | 8 |
| | 15,253 | | 15,253 | 9 |
| | 64,299 | | 64,299 | 10 |
| | 64,299 | | 64,299 | 11 |
| | 70,729 | | 70,729 | 12 |
| | 70,729 | | 70,729 | 13 |
| | 946 | | 946 | 14 |
| | 299 | | 299 | 15 |
| | 7,835 | | 7,835 | 16 |
| | 356 | | 356 | 17 |
| | 256 | | 256 | 18 |
| | 138 | | 138 | 19 |
| | 477,647 | | 477,647 | 20 |
| | 6,444 | | 6,444 | 21 |
| | 1 | | 1 | 22 |
| | 2,147 | | 2,147 | 23 |
| | | | | 24 |
| | 809,045 | | 809,045 | 25 |
| | 15,672 | | 15,672 | 26 |
| 93,795 | | | 93,795 | 27 |
| | 32,400 | | 32,400 | 28 |
| | -644,539 | | -644,539 | 29 |
| | -105,093 | | -105,093 | 30 |
| | 928 | | 928 | 31 |
| | 1,674 | | 1,674 | 32 |
| | | | | 33 |
| | 7,145 | | 7,145 | 34 |
| **3,139,911** | **4,487,135** | **884,389** | **8,511,435** | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered 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. |
|---|---|---|---|---|
| | | | | 1 |
| | -65,055 | | -65,055 | 2 |
| | 4,423 | | 4,423 | 3 |
| | 3,470 | | 3,470 | 4 |
| | 9,185 | | 9,185 | 5 |
| | 227 | | 227 | 6 |
| | | 637,043 | 637,043 | 7 |
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| **3,139,911** | **4,487,135** | **884,389** | **8,511,435** | |

***Schedule Page: 328 Line No.: 1 Column: d***

Represents non-billed redirected MWHs of 3 Phases Renewables, LLC’s service.

***Schedule Page: 328 Line No.: 5 Column: d***

Represents non-billed redirected MWHs of Avangrid Renewables, LLC’s service.

***Schedule Page: 328 Line No.: 6 Column: d***

Contract with Avista Corporation Washington Water Power Division continues until terminated.

***Schedule Page: 328 Line No.: 7 Column: d***

Contract with Avista Corporation Washington Water Power Division continues until terminated.

***Schedule Page: 328 Line No.: 9 Column: d***

Represents non-billed redirected MWHs of Avista Corporation Washington Water Power Division’s service.

***Schedule Page: 328 Line No.: 14 Column: d***

Contract with Bonneville Power Administration continues until terminated.

***Schedule Page: 328 Line No.: 15 Column: d***

Contract with Bonneville Power Administration continues until terminated.

***Schedule Page: 328 Line No.: 16 Column: d***

Contract with Bonneville Power Administration continues until terminated.

***Schedule Page: 328 Line No.: 17 Column: d***

Contract with Bonneville Power Administration continues until terminated.

***Schedule Page: 328 Line No.: 18 Column: d***

Contract with Brookfield Energy Marketing continues until terminated.

***Schedule Page: 328 Line No.: 19 Column: d***

Contract with Brookfield Energy Marketing continues until terminated.

***Schedule Page: 328 Line No.: 21 Column: d***

Represents non-billed redirected MWHs of Calpine Energy Services’ service.

***Schedule Page: 328 Line No.: 23 Column: d***

Contract with Exelon Generation Company LLC expires 01/01/2034.

***Schedule Page: 328 Line No.: 24 Column: d***

Contract with Exelon Generation Company LLC expires 01/01/2034

***Schedule Page: 328 Line No.: 25 Column: d***

Contract with Exelon Generation Company LLC expires 01/01/2034

***Schedule Page: 328 Line No.: 28 Column: d***

Represents non-billed redirected MWHs of Exelon Generation Company LLC’s service.

***Schedule Page: 328 Line No.: 29 Column: d***

Contract with Macquarie Energy LLC continues until terminated.

***Schedule Page: 328 Line No.: 34 Column: d***

Contract with Morgan Stanley Capital Group Inc expires 01/01/2034.

***Schedule Page: 328.1 Line No.: 3 Column: d***

Exchange agreement with PacifiCorp

***Schedule Page: 328.1 Line No.: 4 Column: d***

Contract with PacifiCorp continues until terminated.

***Schedule Page: 328.1 Line No.: 5 Column: d***

Contract with Powerex Corp continues until terminated.

***Schedule Page: 328.1 Line No.: 7 Column: d***

Contract with Powerex Corp continues until terminated.

***Schedule Page: 328.1 Line No.: 8 Column: d***

Contract with Powerex Corp continues until terminated.

***Schedule Page: 328.1 Line No.: 10 Column: c***

Represents the reassignment of PUD No. 1 of Cowlitz County's transmission capacity rights.

***Schedule Page: 328.1 Line No.: 10 Column: d***

Contract with PUD No. 1 of Cowlitz County expires 01/01/2034.

**Schedule Page: 328.1 Line No.: 11 Column: c**

Represents the reassignment of PUD No. 1 of Franklin County's transmission capacity rights.

**Schedule Page: 328.1 Line No.: 11 Column: d**

Contract with PUD No. 1 of Franklin County expires 01/01/2034.

**Schedule Page: 328.1 Line No.: 12 Column: c**

Represents the reassignment of PUD No. 1 of Klickitat County's transmission capacity rights.

**Schedule Page: 328.1 Line No.: 12 Column: d**

Contract with PUD No. 1 of Klickitat County expires 01/01/2034.

**Schedule Page: 328.1 Line No.: 13 Column: c**

Represents the reassignment of PUD No. 1 of Lewis County's transmission capacity rights.

**Schedule Page: 328.1 Line No.: 13 Column: d**

Contract with PUD No. 1 of Lewis County expires 01/01/2034.

**Schedule Page: 328.1 Line No.: 14 Column: d**

Contract with Puget Sound continues until terminated.

**Schedule Page: 328.1 Line No.: 20 Column: d**

Contract with Shell Energy North America (US) LP expires 01/01/2022.

**Schedule Page: 328.1 Line No.: 24 Column: d**

Represents non-billed redirected MWHs of Shell Energy North America (US) LP’s service.

**Schedule Page: 328.1 Line No.: 25 Column: d**

Contract with Shell Energy North America (US) LP expires 01/01/2022.

**Schedule Page: 328.1 Line No.: 27 Column: d**

Represents non-billed redirected MWHs of Shell Energy North America (US) LP’s service.

**Schedule Page: 328.1 Line No.: 28 Column: d**

Contract with Tacoma Power continues until terminated.

**Schedule Page: 328.1 Line No.: 29 Column: d**

Contract with The Energy Authority expires 01/01/2034

**Schedule Page: 328.1 Line No.: 30 Column: d**

Contract with The Energy Authority expires 01/01/2034

**Schedule Page: 328.1 Line No.: 33 Column: d**

Represents non-billed redirected MWHs of The Energy Authority's service.

**Schedule Page: 328.2 Line No.: 1 Column: d**

Represents non-billed redirected MWHs of The Energy Authority's service.

**Schedule Page: 328.2 Line No.: 2 Column: d**

Contract with The Energy Authority expires 01/01/2034

**Schedule Page: 328.2 Line No.: 7 Column: d**

Represents the difference between actual transmission revenue for the year as reflected on the individual line items within this schedule, and the accruals credited during the year to FERC Account 456.1, Revenues from Transmission of Electricity for Others.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## 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 Tarirff (d) | Total Revenue (e) |
|---|---|---|---|---|---|
| 1 | | | | | |
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| 38 | | | | | |
| 39 | | | | | |
| 40 | TOTAL | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## 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: Magawatt-hours Received (c) | TRANSFER OF ENERGY: Magawatt-hours Delivered (d) | EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e) | Energy Charges ($) (f) | Other Charges ($) (g) | Total Cost of Transmission ($) (h) |
|---|---|---|---|---|---|---|---|---|
| 1 | Avista Corp | NF | 330 | 330 | | 1,904 | | 1,904 |
| 2 | Bonneville Power Admin | LFP | | | 63,073,460 | | | 63,073,460 |
| 3 | Bonneville Power Admin | OS | | | | | 19,867,138 | 19,867,138 |
| 4 | Bonneville Power Admin | SFP | 61,259 | 61,259 | | 104,107 | | 104,107 |
| 5 | Bonneville Power Admin | NF | 9,922 | 9,922 | | 36,304 | | 36,304 |
| 6 | Bonneville Power Admin | AD | | | | | 62,179 | 62,179 |
| 7 | Columbia River PUD | NF | 6 | 6 | | 2,461 | | 2,461 |
| 8 | Columbia River PUD | SFP | 6 | 6 | | 2,954 | | 2,954 |
| 9 | Diversified Energy Tran | OS | | | | | -659,836 | -659,836 |
| 10 | EDF Renewables | OS | | | | | -148,900 | -148,900 |
| 11 | Eugene Water & Electric | NF | 12 | 12 | | 18,900 | | 18,900 |
| 12 | Eugene Water & Electric | LFP | 12 | 12 | | 18,900 | | 18,900 |
| 13 | Idaho Power Company | NF | 788 | 788 | | 7,018 | | 7,018 |
| 14 | Los Angeles Dept Water | NF | | | | | | |
| 15 | McMinnville Water & Lig | NF | 494 | 494 | | 4,485 | | 4,485 |
| 16 | McMinnville Water & Lig | LFP | 328 | 328 | | 3,051 | | 3,051 |
| | TOTAL | | 109,060 | 109,060 | 63,073,460 | 336,573 | 21,784,284 | 85,194,317 |

| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

## 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<br>Magawatt-hours Received (c) | Magawatt-hours Delivered (d) | EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS<br>Demand Charges ($) (e) | Energy Charges ($) (f) | Other Charges ($) (g) | Total Cost of Transmission ($) (h) |
|---|---|---|---|---|---|---|---|---|
| 1 | Montana, State of | OS | | | | | 2,546,855 | 2,546,855 |
| 2 | NorthWestern Energy | NF | 32,642 | 32,642 | | 145,184 | | 145,184 |
| 3 | PacifiCorp | OS | | | | | 116,848 | 116,848 |
| 4 | PacifiCorp | NF | | | | -12,172 | | -12,172 |
| 5 | Powerex | SFP | 11 | 11 | | 14 | | 14 |
| 6 | Seattle City Light | NF | 3,250 | 3,250 | | 3,463 | | 3,463 |
| 7 | | | | | | | | |
| 8 | | | | | | | | |
| 9 | | | | | | | | |
| 10 | | | | | | | | |
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| 13 | | | | | | | | |
| 14 | | | | | | | | |
| 15 | | | | | | | | |
| 16 | | | | | | | | |
| | TOTAL | | 109,060 | 109,060 | 63,073,460 | 336,573 | 21,784,284 | 85,194,317 |

***Schedule Page: 332 Line No.: 2 Column: b***

Represents the Bonneville Power Administration PTP contracts that have termination dates that range from 10/31/2019 thru 9/30/2027.

***Schedule Page: 332 Line No.: 3 Column: g***

Represents Bonneville Power Administration Ancillary Transmission Services.

***Schedule Page: 332 Line No.: 6 Column: g***

Represents Bonneville Power Administration prior period adjustments from 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.: 12 Column: b***

Represents Eugene Water & Electric Board contract which terminates on 12/1/2020.

***Schedule Page: 332 Line No.: 16 Column: b***

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

***Schedule Page: 332.1 Line No.: 1 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.: 3 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 | 2,994,299 |
| 2 | Nuclear Power Research Expenses | |
| 3 | Other Experimental and General Research Expenses | 1,815,665 |
| 4 | Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities | 1,792,176 |
| 5 | Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000 | |
| 6 | Involuntary Severance | 1,464,082 |
| 7 | Directors Pension | 56,943 |
| 8 | Directors Fees & Expenses | 81,038 |
| 9 | Directors and Officers Expenses | 2,274,445 |
| 10 | Misc Admin Expenses | 296,809 |
| 11 | Colstrip - PPL Montana | 695,456 |
| 12 | Internal & External Reporting | |
| 13 | Misc Admin R&D Expenses | 13,911 |
| 14 | | |
| 15 | | |
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| 17 | | |
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| 45 | | |
| 46 | TOTAL | 11,484,824 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition 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 | | | 46,134,140 | | 46,134,140 |
| 2 | Steam Production Plant | 32,521,049 | 6,315,173 | | | 38,836,222 |
| 3 | Nuclear Production Plant | | | | | |
| 4 | Hydraulic Production Plant-Conventional | 18,963,678 | 69 | | | 18,963,747 |
| 5 | Hydraulic Production Plant-Pumped Storage | | | | | |
| 6 | Other Production Plant | 82,173,182 | 566,830 | | | 82,740,012 |
| 7 | Transmission Plant | 12,608,561 | 1 | | | 12,608,562 |
| 8 | Distribution Plant | 106,158,861 | 9,337 | | | 106,168,198 |
| 9 | Regional Transmission and Market Operation | | | | | |
| 10 | General Plant | 38,248,449 | 99 | | | 38,248,548 |
| 11 | Common Plant-Electric | | | | | |
| 12 | TOTAL | 290,673,780 | 6,891,509 | 46,134,140 | | 343,699,429 |

### B. Basis for Amortization Charges

Five year and ten year amortization of computer software.

Five year and twenty-five year amortization of permits.

Thirty year, forty year, and fifty year amortization of hydro licensing costs.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## 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 | Note: Complete data | | | | | | |
| 13 | will be provided in | | | | | | |
| 14 | the 2018 Form 1 | | | | | | |
| 15 | (new depreciation | | | | | | |
| 16 | study with rates | | | | | | |
| 17 | effective 1/1/18). | | | | | | |
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| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original (2) [ ] A Resubmission | / / | End of 2017/Q4 |

## REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

| 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 | | 260,210 | 260,210 | |
| 2 | Docket No. RM06-16 | | | | |
| 3 | | | | | |
| 4 | FERC-NERC Reliability | | 196,268 | 196,268 | |
| 5 | Docket No. RM06-22 | | | | |
| 6 | | | | | |
| 7 | FERC-Complaint concerning PGE obligation to | | 21,546 | 21,546 | |
| 8 | integrate with & purchase from PaTu Wind Farm | | | | |
| 9 | Docket No.15-1237 | | | | |
| 10 | | | | | |
| 11 | FERC-Energy Imbalance Markets | | 20,255 | 20,255 | |
| 12 | Docket No. ER15-1919 | | | | |
| 13 | | | | | |
| 14 | NERC/FERC/WECC Compliance | | 81,962 | 81,962 | |
| 15 | Docket EL17-81 | | | | |
| 16 | | | | | |
| 17 | OPUC matters less than $25,000 | | 150,894 | 150,894 | |
| 18 | | | | | |
| 19 | FERC matters less than $25,000 | | 19,377 | 19,377 | |
| 20 | | | | | |
| 21 | Non Docs matters | | 240,419 | 240,419 | |
| 22 | | | | | |
| 23 | PGE request for General Rate Provisions 2018 | | 212,585 | 212,585 | |
| 24 | UE-319 | | | | |
| 25 | | | | | |
| 26 | NIPPC et al v PGE re QF complaint (PURPA) | | 138,752 | 138,752 | |
| 27 | UM-1805 | | | | |
| 28 | | | | | |
| 29 | PGE v Covanta Marion Inc | | 30,261 | 30,261 | |
| 30 | UM-1887 (see docket EL17-81-000) | | | | |
| 31 | | | | | |
| 32 | Integrated Resource Plan 2016 | | 71,830 | 71,830 | |
| 33 | LC-66 | | | | |
| 34 | | | | | |
| 35 | Gresham Privilege Tax | | 66,734 | 66,734 | |
| 36 | ADV-523 | | | | |
| 37 | | | | | |
| 38 | Appl. to lower the std price & std contract | | 79,849 | 79,849 | |
| 39 | elig cap for Solar Qualif Activ UM-1854 | | | | |
| 40 | | | | | |
| 41 | Waiver for Competitive Bidding Guidelines | | 100,877 | 100,877 | |
| 42 | UM-1892 | | | | |
| 43 | | | | | |
| 44 | Appl to Update Sch201 Qualifying Facility Info | | 28,497 | 28,497 | |
| 45 | UM-1728 | | | | |
| 46 | TOTAL | | 1,720,316 | 1,720,316 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

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 | | | | | | | |
| Department<br>(f) | Account No.<br>(g) | Amount<br>(h) | Deferred to Account 182.3<br>(i) | Contra Account<br>(j) | Amount<br>(k) | Deferred in Account 182.3 End of Year<br>(l) | Line No. |
| | 928 | 260,210 | | | | | 1 |
| | | | | | | | 2 |
| | | | | | | | 3 |
| | 928 | 196,268 | | | | | 4 |
| | | | | | | | 5 |
| | | | | | | | 6 |
| | 928 | 21,546 | | | | | 7 |
| | | | | | | | 8 |
| | | | | | | | 9 |
| | | | | | | | 10 |
| | 928 | 20,255 | | | | | 11 |
| | | | | | | | 12 |
| | | | | | | | 13 |
| | 928 | 81,962 | | | | | 14 |
| | | | | | | | 15 |
| | | | | | | | 16 |
| | 928 | 150,894 | | | | | 17 |
| | | | | | | | 18 |
| | 928 | 19,377 | | | | | 19 |
| | | | | | | | 20 |
| | 928 | 240,419 | | | | | 21 |
| | | | | | | | 22 |
| | 928 | 212,585 | | | | | 23 |
| | | | | | | | 24 |
| | | | | | | | 25 |
| | 928 | 138,752 | | | | | 26 |
| | | | | | | | 27 |
| | | | | | | | 28 |
| | 928 | 30,261 | | | | | 29 |
| | | | | | | | 30 |
| | | | | | | | 31 |
| | 928 | 71,830 | | | | | 32 |
| | | | | | | | 33 |
| | | | | | | | 34 |
| | 928 | 66,734 | | | | | 35 |
| | | | | | | | 36 |
| | | | | | | | 37 |
| | 928 | 79,849 | | | | | 38 |
| | | | | | | | 39 |
| | | | | | | | 40 |
| | 928 | 100,877 | | | | | 41 |
| | | | | | | | 42 |
| | | | | | | | 43 |
| | 928 | 28,497 | | | | | 44 |
| | | | | | | | 45 |
| | | 1,720,316 | | | | | 46 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & 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) | Electric R, D & D Performed Internally - Generation |
| 2 | A(1)(d) | Nuclear |
| 3 | A(1)(e) | Unconventional Generation |
| 4 | A(2) | Electric R, D & D Performed Internally - Transmission |
| 5 | A(3) | Electric R, D & D Performed Internally - Distribution |
| 6 | A(5) | Electric R, D & D Performed Internally - Environment |
| 7 | A(6) | Electric R, D & D Performed Internally - Other |
| 8 | B(1) | Electric R, D & D Performed Externally |
| 9 | | |
| 10 | | |
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| 20 | | |
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| 22 | | |
| 23 | | |
| 24 | Totals | |
| 25 | | |
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| 37 | | |
| 38 | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## 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 Account (e) | AMOUNTS CHARGED IN CURRENT YEAR Amount (f) | Unamortized Accumulation (g) | Line No. |
|---|---|---|---|---|---|
| | | | | | 1 |
| | | | | | 2 |
| 655,164 | | 930.2 | 655,164 | | 3 |
| 1,549 | | 930.2 | 1,549 | | 4 |
| 1,076,655 | | 930.2 | 1,076,655 | | 5 |
| | | | | | 6 |
| 3,261 | | 930.2 | 3,261 | | 7 |
| | 79,036 | 930.2 | 79,036 | | 8 |
| | | | | | 9 |
| | | | | | 10 |
| | | | | | 11 |
| | | | | | 12 |
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| | | | | | 22 |
| | | | | | 23 |
| 1,736,629 | 79,036 | | 1,815,665 | | 24 |
| | | | | | 25 |
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| | | | | | 38 |

| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

| Line No. | Classification (a) | Direct Payroll Distribution (b) | Allocation of Payroll charged for Clearing Accounts (c) | Total (d) |
|---|---|---|---|---|
| 1 | Electric | | | |
| 2 | Operation | | | |
| 3 | Production | 29,608,877 | | |
| 4 | Transmission | 4,271,243 | | |
| 5 | Regional Market | | | |
| 6 | Distribution | 16,072,572 | | |
| 7 | Customer Accounts | 25,271,013 | | |
| 8 | Customer Service and Informational | 7,262,528 | | |
| 9 | Sales | | | |
| 10 | Administrative and General | 38,401,649 | | |
| 11 | TOTAL Operation (Enter Total of lines 3 thru 10) | 120,887,882 | | |
| 12 | Maintenance | | | |
| 13 | Production | 14,058,863 | | |
| 14 | Transmission | 1,524,528 | | |
| 15 | Regional Market | | | |
| 16 | Distribution | 29,548,638 | | |
| 17 | Administrative and General | 819,179 | | |
| 18 | TOTAL Maintenance (Total of lines 13 thru 17) | 45,951,208 | | |
| 19 | Total Operation and Maintenance | | | |
| 20 | Production (Enter Total of lines 3 and 13) | 43,667,740 | | |
| 21 | Transmission (Enter Total of lines 4 and 14) | 5,795,771 | | |
| 22 | Regional Market (Enter Total of Lines 5 and 15) | | | |
| 23 | Distribution (Enter Total of lines 6 and 16) | 45,621,210 | | |
| 24 | Customer Accounts (Transcribe from line 7) | 25,271,013 | | |
| 25 | Customer Service and Informational (Transcribe from line 8) | 7,262,528 | | |
| 26 | Sales (Transcribe from line 9) | | | |
| 27 | Administrative and General (Enter Total of lines 10 and 17) | 39,220,828 | | |
| 28 | TOTAL Oper. and Maint. (Total of lines 20 thru 27) | 166,839,090 | 20,175,039 | 187,014,129 |
| 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 | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

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 Terminaling and Processing (Total of lines 31 thru | | | |
| 56 | Transmission (Lines 35 and 47) | | | |
| 57 | Distribution (Lines 36 and 48) | | | |
| 58 | Customer Accounts (Line 37) | | | |
| 59 | Customer Service and Informational (Line 38) | | | |
| 60 | Sales (Line 39) | | | |
| 61 | Administrative and General (Lines 40 and 49) | | | |
| 62 | TOTAL Operation and Maint. (Total of lines 52 thru 61) | | | |
| 63 | Other Utility Departments | | | |
| 64 | Operation and Maintenance | | | |
| 65 | TOTAL All Utility Dept. (Total of lines 28, 62, and 64) | 166,839,090 | 20,175,039 | 187,014,129 |
| 66 | Utility Plant | | | |
| 67 | Construction (By Utility Departments) | | | |
| 68 | Electric Plant | 92,426,066 | 4,102,190 | 96,528,256 |
| 69 | Gas Plant | | | |
| 70 | Other (provide details in footnote): | | | |
| 71 | TOTAL Construction (Total of lines 68 thru 70) | 92,426,066 | 4,102,190 | 96,528,256 |
| 72 | Plant Removal (By Utility Departments) | | | |
| 73 | Electric Plant | 633,388 | 44,250 | 677,638 |
| 74 | Gas Plant | | | |
| 75 | Other (provide details in footnote): | | | |
| 76 | TOTAL Plant Removal (Total of lines 73 thru 75) | 633,388 | 44,250 | 677,638 |
| 77 | Other Accounts (Specify, provide details in footnote): | | | |
| 78 | Other Income and Deductions | 1,673,968 | 145,175 | 1,819,143 |
| 79 | Co-Owner Shares of Generating Facilities | 5,091,622 | 155,590 | 5,247,212 |
| 80 | Other | 1,157,990 | 4,132,618 | 5,290,608 |
| 81 | Payroll Allocated | 28,754,862 | -28,754,862 | |
| 82 | | | | |
| 83 | | | | |
| 84 | | | | |
| 85 | | | | |
| 86 | | | | |
| 87 | | | | |
| 88 | | | | |
| 89 | | | | |
| 90 | | | | |
| 91 | | | | |
| 92 | | | | |
| 93 | | | | |
| 94 | | | | |
| 95 | TOTAL Other Accounts | 36,678,442 | -24,321,479 | 12,356,963 |
| 96 | TOTAL SALARIES AND WAGES | 296,576,986 | | 296,576,986 |

| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>*(Mo, Da, Yr)*<br>/ / | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

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.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

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

| Line No. | Description of Item(s)<br>(a) | Balance at End of Quarter 1<br>(b) | Balance at End of Quarter 2<br>(c) | Balance at End of Quarter 3<br>(d) | Balance at End of Year<br>(e) |
|---|---|---|---|---|---|
| 1 | Energy | | | | |
| 2 | Net Purchases (Account 555) | 155,893 | 629,407 | 760,085 | 7,374,012 |
| 3 | Net Sales (Account 447) | 6,877,137 | 8,660,196 | 18,962,313 | 50,167,121 |
| 4 | Transmission Rights | | | | |
| 5 | Ancillary Services | | | | |
| 6 | Other Items (list separately) | | | | |
| 7 | | | | | |
| 8 | | | | | |
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| 41 | | | | | |
| 42 | | | | | |
| 43 | | | | | |
| 44 | | | | | |
| 45 | | | | | |
| 46 | TOTAL | 7,033,030 | 9,289,603 | 19,722,398 | 57,541,133 |

***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.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (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.

| | | Amount Purchased for the Year | | | Amount Sold for the Year | | |
|---|---|---|---|---|---|---|---|
| | | Usage - Related Billing Determinant | | | Usage - Related Billing Determinant | | |
| Line No. | Type of Ancillary Service (a) | Number of Units (b) | Unit of Measure (c) | Dollars (d) | Number of Units (e) | Unit of Measure (f) | Dollars (g) |
| 1 | Scheduling, System Control and Dispatch | 79,818 | MW | 19,896,421 | 5,835,503 | Various | 141,501 |
| 2 | Reactive Supply and Voltage | | | | 3,777,422 | Various | 124,570 |
| 3 | Regulation and Frequency Response | | | | 3,777,422 | Various | 280,508 |
| 4 | Energy Imbalance | 105,644 | MWh | 1,537,737 | 23,621 | MWh | 770,550 |
| 5 | Operating Reserve - Spinning | | | | 3,777,422 | MWh | 322,967 |
| 6 | Operating Reserve - Supplement | | | | 3,777,422 | MWh | 322,967 |
| 7 | Other | | | | | | |
| 8 | Total (Lines 1 thru 7) | 185,462 | | 21,434,158 | 20,968,812 | | 1,963,063 |

***Schedule Page: 398 Line No.: 1 Column: g***

| Scheduling, System Control and Dispatch | | No. of Units | Amount |
|---|---|---|---|
| MW Day | DAILY | 8,975 | $ 308 |
| MW Hour | HOURLY | 85,905 | $ 1,733 |
| MW Month | MONTHLY | 185 | $ 2,311 |
| MW Year | YEARLY | 1,963,201 | $ 99,377 |
| Sum of Peak Demand (KW) | | 3,777,237 | $ 37,772 |
| | | 5,835,503 | 141,501 |

***Schedule Page: 398 Line No.: 2 Column: g***

| Reactive Supply and Voltage | | No. of Units | Amount |
|---|---|---|---|
| MW Month | MONTHLY | 185 | $ 7,104 |
| MW Year | YEARLY | 0 | $ 4,149 |
| Sum of Peak Demand (KW) | | 3,777,237 | $ 113,317 |
| | | 3,777,422 | 124,570 |

***Schedule Page: 398 Line No.: 3 Column: g***

| Regulation and Frequency Response | | No. of Units | Amount |
|---|---|---|---|
| MW Month | MONTHLY | 185 | $ 16,101 |
| Sum of Peak Demand (KW) | | 3,777,237 | $ 264,407 |
| | | 3,777,422 | 280,508 |

***Schedule Page: 398 Line No.: 4 Column: d***

The Energy Imbalance Cost (EIC) is equal to the market price of energy for each hour based on the published Dow Jones Electricity Price Index Mid-Columbia daily non-firm on-peak or off-peak price.

***Schedule Page: 398 Line No.: 4 Column: g***

The Energy Imbalance Cost (EIC) is equal to the market price of energy for each hour based on the published Dow Jones Electricity Price Index Mid-Columbia daily non-firm on-peak or off-peak price.

***Schedule Page: 398 Line No.: 5 Column: g***

| Operating Reserve - Spinning | | No. of Units | Amount |
|---|---|---|---|
| MW Month | MONTHLY | 3,777,422 | $ 322,967 |
| | | 3,777,422 | 322,967 |

***Schedule Page: 398 Line No.: 6 Column: g***

| Operating Reserve - Supplement | | No. of Units | Amount |
|---|---|---|---|
| MW Month | MONTHLY | 3,777,422 | $ 322,967 |
| | | 3,777,422 | 322,967 |

***Schedule Page: 398 Line No.: 8 Column: b***

Total is not meaningful due to the summation of amounts of dissimilar units of measure.

***Schedule Page: 398 Line No.: 8 Column: e***

Total is not meaningful due to the summation of amounts of dissimilar units of measure.

# 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<br>(a) | Monthly Peak MW - Total<br>(b) | Day of Monthly Peak<br>(c) | Hour of Monthly Peak<br>(d) | Firm Network Service for Self<br>(e) | Firm Network Service for Others<br>(f) | Long-Term Firm Point-to-point Reservations<br>(g) | Other Long-Term Firm Service<br>(h) | Short-Term Firm Point-to-point Reservation<br>(i) | Other Service<br>(j) |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | January | 5,121 | 6 | 800 | 3,502 | 236 | 1,577 | | 3,812 | 75 |
| 2 | February | 4,723 | 1 | 1900 | 3,152 | 274 | 1,577 | | 3,812 | |
| 3 | March | 4,570 | 6 | 1900 | 2,855 | 269 | 1,577 | | 3,812 | |
| 4 | Total for Quarter 1 | | | | 9,509 | 779 | 4,731 | | 11,436 | 75 |
| 5 | April | 3,803 | 25 | 1900 | 2,315 | 257 | 1,577 | | 3,812 | |
| 6 | May | 4,090 | 22 | 2000 | 2,877 | 298 | 1,577 | | 3,812 | |
| 7 | June | 4,637 | 24 | 1900 | 3,038 | 286 | 1,577 | | 3,812 | |
| 8 | Total for Quarter 2 | | | | 8,230 | 841 | 4,731 | | 11,436 | |
| 9 | July | 4,692 | 31 | 1900 | 3,175 | 308 | 1,587 | | 3,812 | 113 |
| 10 | August | 5,103 | 2 | 1800 | 3,654 | 330 | 1,587 | | 3,831 | 358 |
| 11 | September | 4,906 | 6 | 1900 | 3,033 | 282 | 1,587 | | 3,831 | 368 |
| 12 | Total for Quarter 3 | | | | 9,862 | 920 | 4,761 | | 11,474 | 839 |
| 13 | October | 3,855 | 12 | 2000 | 2,293 | 262 | 1,587 | | 3,830 | |
| 14 | November | 4,345 | 30 | 1900 | 2,788 | 247 | 1,587 | | 3,842 | 53 |
| 15 | December | 4,783 | 22 | 1900 | 2,945 | 227 | 1,587 | | 3,857 | 14 |
| 16 | Total for Quarter 4 | | | | 8,026 | 736 | 4,761 | | 11,529 | 67 |
| 17 | Total Year to Date/Year | | | | 35,627 | 3,276 | 18,984 | | 45,875 | 981 |

| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

## MONTHLY TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM: Colstrip

| Line No. | Month<br>(a) | Monthly Peak MW - Total<br>(b) | Day of Monthly Peak<br>(c) | Hour of Monthly Peak<br>(d) | Firm Network Service for Self<br>(e) | Firm Network Service for Others<br>(f) | Long-Term Firm Point-to-point Reservations<br>(g) | Other Long-Term Firm Service<br>(h) | Short-Term Firm Point-to-point Reservation<br>(i) | Other Service<br>(j) |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | January | 287 | 30 | 800 | | | 307 | | | |
| 2 | February | 286 | 5 | 700 | | | 307 | | | |
| 3 | March | 288 | 26 | 2300 | | | 307 | | | |
| 4 | Total for Quarter 1 | | | | | | 921 | | | |
| 5 | April | 291 | 17 | 2100 | | | 307 | | | |
| 6 | May | 272 | 2 | 2000 | | | 307 | | | |
| 7 | June | 285 | 29 | 2400 | | | 307 | | | |
| 8 | Total for Quarter 2 | | | | | | 921 | | | |
| 9 | July | 287 | 8 | 600 | | | 307 | | | |
| 10 | August | 290 | 26 | 600 | | | 307 | | | |
| 11 | September | 289 | 24 | 400 | | | 307 | | | |
| 12 | Total for Quarter 3 | | | | | | 921 | | | |
| 13 | October | 295 | 16 | 400 | | | 307 | | | |
| 14 | November | 291 | 24 | 500 | | | 307 | | | |
| 15 | December | 291 | 5 | 2300 | | | 307 | | | |
| 16 | Total for Quarter 4 | | | | | | 921 | | | |
| 17 | Total Year to Date/Year | | | | | | 3,684 | | | |
| | | | | | | | | | | |

| Name of Respondent<br>Portland General Electric Company | This Report is:<br>(1) X An Original<br>(2) __ A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>2017/Q4 |
|---|---|---|---|

FOOTNOTE DATA

**Schedule Page: 400 Line No.: 4 Column: g**

Long Term Firm Point-to-Point Reservations: Q1

| Reservation # | Customer | MW Granted Jan 2017 | MW Granted Feb 2017 | MW Granted Mar 2017 | Earliest Termination Date |
|---|---|---|---|---|---|
| 432190 | Portland General Electric Company | 100 | 100 | 100 | 1/1/2022 |
| 71472976 | Shell Energy North America (US) LP | 200 | 200 | 200 | 1/1/2022 |
| 74382640 | Portland General Electric Company | 100 | 100 | 100 | 7/1/2017 |
| 74566698 | Portland General Electric Company | 100 | 100 | 100 | 1/1/2022 |
| 76073144 | Portland General Electric Company | (14) | (14) | (14) | 7/1/2017 |
| 77316434 | Avista Corp | 100 | 100 | 100 | 1/1/2023 |
| 77594664 | Powerex Inc. | 165 | 165 | 165 | 6/1/2018 |
| 77594666 | Powerex Inc. | 97 | 97 | 97 | 1/1/2022 |
| 79072075 | Powerex Inc. | 10 | 10 | 10 | 1/1/2034 |
| 79082732 | Portland General Electric Company | 10 | 10 | 10 | 1/1/2034 |
| 79084421 | Exelon Generation Company, LLC | 10 | 10 | 10 | 1/1/2034 |
| 79091530 | Morgan Stanley Capital Group Inc. | 10 | 10 | 10 | 1/1/2034 |
| 79091653 | Public Utility District No. 1 of Klickitat County | 11 | 11 | 11 | 1/1/2034 |
| 79091680 | The Energy Authority, Inc. | 10 | 10 | 10 | 1/1/2034 |
| 79092316 | Public Utility District No. 1 of Lewis County | 11 | 11 | 11 | 1/1/2034 |
| 79092388 | Public Utility District No. 1 of Franklin County | 10 | 10 | 10 | 1/1/2034 |
| 79092678 | Public Utility District No. 1 of Cowlitz County | 10 | 10 | 10 | 1/1/2034 |
| 79875117 | Portland General Electric Company | 250 | 250 | 250 | 1/1/2020 |
| 80266877 | Powerex Inc. | 10 | 10 | 10 | 1/1/2034 |
| 81712548 | Portland General Electric Company | 177 | 177 | 177 | 1/1/2021 |
| 82107491 | Portland General Electric Company | 200 | 200 | 200 | 1/1/2022 |
| | | **1,577** | **1,577** | **1,577** | |

**Schedule Page: 400 Line No.: 4 Column: i**

Short-Term Firm Point-to-Point Transmission Service Requests at date and time of monthly Transmission Service Peak for Q1:

| Reservation # | Customer | MW Granted Jan 2017 | MW Granted Feb 2017 | MW Granted Mar 2017 |
|---|---|---|---|---|
| 83954322 | Portland General Electric Company | 3,300 | | |
| 83954474 | Portland General Electric Company | 10 | | |
| 83971032 | Portland General Electric Company | 500 | | |
| 83971037 | Portland General Electric Company | 2 | | |
| 84139756 | Portland General Electric Company | | 3,300 | |
| 84139809 | Portland General Electric Company | | 10 | |
| 84140306 | Portland General Electric Company | | 500 | 500 |
| 84140319 | Portland General Electric Company | | 2 | 2 |
| 84299847 | Portland General Electric Company | | | 3,300 |
| 84299861 | Portland General Electric Company | | | 10 |
| | **Total** | **3,812** | **3,812** | **3,812** |

**Schedule Page: 400 Line No.: 4 Column: j**

Other Service:

The entries represent the total amount scheduled under non-firm reservations (daily and/or hourly) at the date and time of transmission system peak for each month. (NONFIRM SCHEDULES)

***Schedule Page: 400 Line No.: 8 Column: g***

Long Term Firm Point-to-Point Reservations: Q2

| Reservation # | Customer | MW Granted Apr 2017 | MW Granted May 2017 | MW Granted Jun 2017 | Earliest Termination Date |
|---|---|---|---|---|---|
| 432190 | Portland General Electric Company | 100 | 100 | 100 | 01/01/2022 |
| 71472976 | Shell Energy North America (US) LP | 200 | 200 | 200 | 01/01/2022 |
| 74382640 | Portland General Electric Company | 100 | 100 | 100 | 07/01/2017 |
| 74566698 | Portland General Electric Company | 100 | 100 | 100 | 01/01/2022 |
| 76073144 | Portland General Electric Company | (14) | (14) | (14) | 07/01/2017 |
| 77316434 | Avista Corp | 100 | 100 | 100 | 01/01/2023 |
| 77594664 | Powerex Inc. | 165 | 165 | 165 | 06/01/2018 |
| 77594666 | Powerex Inc. | 97 | 97 | 97 | 01/01/2022 |
| 79072075 | Powerex Inc. | 10 | 10 | 10 | 01/01/2034 |
| 79082732 | Portland General Electric Company | 10 | 10 | 10 | 01/01/2034 |
| 79084421 | Exelon Generation Company, LLC | 10 | 10 | 10 | 01/01/2034 |
| 79091530 | Morgan Stanley Capital Group Inc. | 10 | 10 | 10 | 01/01/2034 |
| 79091653 | Public Utility District No 1 of Klickitat County | 11 | 11 | 11 | 01/01/2034 |
| 79091680 | The Energy Authority, Inc. | 10 | 10 | 10 | 01/01/2034 |
| 79092316 | Public Utility District No. 1 of Lewis County | 11 | 11 | 11 | 01/01/2034 |
| 79092388 | Public Utility District No 1 of Franklin County | 10 | 10 | 10 | 01/01/2034 |
| 79092678 | Public Utility District No 1 of Cowlitz County | 10 | 10 | 10 | 01/01/2034 |
| 79875117 | Portland General Electric Company | 250 | 250 | 250 | 01/01/2020 |
| 80266877 | Powerex Inc. | 10 | 10 | 10 | 01/01/2034 |
| 81712548 | Portland General Electric Company | 177 | 177 | 177 | 01/01/2021 |
| 82107491 | Portland General Electric Company | 200 | 200 | 200 | 01/01/2022 |
| | | **1,577** | **1,577** | **1,577** | |

***Schedule Page: 400 Line No.: 8 Column: i***

Short-Term Firm Point-to-Point Transmission Service Requests at date and time of monthly Transmission Service Peak for Q2:

| Reservation # | Customer | MW Granted Apr 2017 | MW Granted May 2017 | MW Granted Jun 2017 |
|---|---|---|---|---|
| 84140306 | Portland General Electric Company | 500 | 500 | 500 |
| 84140319 | Portland General Electric Company | 2 | 2 | 2 |
| 84484754 | Portland General Electric Company | 3,300 | | |
| 84484772 | Portland General Electric Company | 10 | | |
| 84688818 | Portland General Electric Company | | 3,300 | |
| 84688836 | Portland General Electric Company | | 10 | |
| 84859950 | Portland General Electric Company | | | 3,300 |
| 84860008 | Portland General Electric Company | | | 10 |
| | **Total** | **3,812** | **3,812** | **3,812** |

***Schedule Page: 400 Line No.: 12 Column: g***

Long Term Firm Point-to-Point Reservations: Q3

| Reservation # | Customer | MW Granted Jul 2017 | MW Granted Aug 2017 | MW Granted Sep 2017 | Earliest Termination Date |
|---|---|---|---|---|---|
| 432190 | Portland General Electric Company | 100 | 100 | 100 | 01/01/2022 |
| 71472976 | Shell Energy North America (US) LP | 200 | 200 | 200 | 01/01/2022 |

| | | | | | |
|---|---|---|---|---|---|
| 74566698 | Portland General Electric Company | 100 | 100 | 100 | 01/01/2022 |
| 77316434 | Avista Corp | 100 | 100 | 100 | 01/01/2023 |
| 77594664 | Powerex Inc. | 165 | 165 | 165 | 06/01/2018 |
| 77594666 | Powerex Inc. | 97 | 97 | 97 | 01/01/2022 |
| 79072075 | Powerex Inc. | 10 | 10 | 10 | 01/01/2034 |
| 79082732 | Portland General Electric Company | 10 | 10 | 10 | 01/01/2034 |
| 79084421 | Exelon Generation Company, LLC | 10 | 10 | 10 | 01/01/2034 |
| 79091330 | Rainbow Energy Marketing Corp. | 10 | 10 | 10 | 01/01/2034 |
| 79091530 | Morgan Stanley Capital Group Inc. | 10 | 10 | 10 | 01/01/2034 |
| 79091653 | Public Utility District No. 1 of Klickitat County | 11 | 11 | 11 | 01/01/2034 |
| 79091680 | The Energy Authority, Inc. | 10 | 10 | 10 | 01/01/2034 |
| 79092316 | Public Utility District No. 1 of Lewis County | 11 | 11 | 11 | 01/01/2034 |
| 79092388 | Public Utility District No. 1 of Franklin County | 10 | 10 | 10 | 01/01/2034 |
| 79092678 | Public Utility District No. 1 of Cowlitz County | 10 | 10 | 10 | 01/01/2034 |
| 79875117 | Portland General Electric Company | 250 | 250 | 250 | 01/01/2020 |
| 80266877 | Powerex Inc. | 10 | 10 | 10 | 01/01/2034 |
| 81712548 | Portland General Electric Company | 177 | 177 | 177 | 01/01/2021 |
| 82090827 | Portland General Electric Company | 86 | 86 | 86 | 07/01/2022 |
| 82107491 | Portland General Electric Company | 200 | 200 | 200 | 01/01/2022 |
| | | **1,587** | **1,587** | **1,587** | |

***Schedule Page: 400 Line No.: 12 Column: i***

Short-Term Firm Point-to-Point Transmission Service Requests at date and time of monthly Transmission Service Peak for Q3:

| Reservation # | Customer | MW Granted Jul 2017 | MW Granted Aug 2017 | MW Granted Sep 2017 |
|---|---|---|---|---|
| 84140306 | Portland General Electric Company | 500 | 500 | 500 |
| 84140319 | Portland General Electric Company | 2 | 2 | 2 |
| 85030361 | Portland General Electric Company | 3,300 | | |
| 85030368 | Portland General Electric Company | 10 | | |
| 85134988 | Portland General Electric Company | | 3,289 | 3,289 |
| 85139776 | Portland General Electric Company | | 40 | 40 |
| | **Total** | **3,812** | **3,831** | **3,831** |

***Schedule Page: 400 Line No.: 12 Column: j***

Other Service:

The entries represent the total amount scheduled under non-firm reservations (daily and/or hourly) at the date and time of transmission system peak for each month. (NONFIRM SCHEDULES)

***Schedule Page: 400 Line No.: 16 Column: g***

Long Term Firm Point-to-Point Reservations: Q4

| Reservation # | Customer | MW Granted Oct 2017 | MW Granted Nov 2017 | MW Granted Dec 2017 | Earliest Termination Date |
|---|---|---|---|---|---|
| 432190 | Portland General Electric Company | 100 | 100 | 100 | 01/01/2022 |
| 71472976 | Shell Energy North America (US) LP | 200 | 200 | 200 | 01/01/2022 |
| 77594666 | Powerex Inc. | 97 | 97 | 97 | 01/01/2022 |
| 74566698 | Portland General Electric Company | 100 | 100 | 100 | 01/01/2022 |
| 77316434 | Avista Corp | 100 | 100 | 100 | 01/01/2023 |
| 77594664 | Powerex Inc. | 165 | 165 | 165 | 06/01/2018 |

| | | | | | |
|---|---|---|---|---|---|
| 79072075 | Powerex Inc. | 10 | 10 | 10 | 01/01/2034 |
| 79082732 | Portland General Electric Company | 10 | 10 | 10 | 01/01/2034 |
| 79084421 | Exelon Generation Company, LLC | 10 | 10 | 10 | 01/01/2034 |
| 79091330 | Rainbow Energy Marketing Corp. | 10 | 10 | 10 | 01/01/2034 |
| 79091530 | Morgan Stanley Capital Group | 10 | 10 | 10 | 01/01/2034 |
| 79091653 | Public Utility District No. 1 of Klickitat County | 11 | 11 | 11 | 01/01/2034 |
| 79091680 | The Energy Authority | 10 | 10 | 10 | 01/01/2034 |
| 79092316 | Public Utility District No. 1 of Lewis County | 11 | 11 | 11 | 01/01/2034 |
| 79092388 | Public Utility District No. 1 of Franklin County | 10 | 10 | 10 | 01/01/2034 |
| 79092678 | Public Utility District No. 1 of Cowlitz County | 10 | 10 | 10 | 01/01/2034 |
| 79875117 | Portland General Electric Company | 250 | 250 | 250 | 01/01/2034 |
| 80266877 | Powerex Inc. | 10 | 10 | 10 | 01/01/2034 |
| 81712548 | Portland General Electric Company | 177 | 177 | 177 | 01/01/2021 |
| 82090827 | Portland General Electric Company | 86 | 86 | 86 | 07/01/2022 |
| 82107491 | Portland General Electric Company | 200 | 200 | 200 | 01/01/2022 |
| | | **1,587** | **1,587** | **1,587** | |

***Schedule Page: 400 Line No.: 16 Column: i***

Short-Term Firm Point-to-Point Transmission Service Requests at date and time of monthly Transmission Service Peak for Q4:

| Reservation # | Customer | MW Granted Oct 2017 | MW Granted Nov 2017 | MW Granted Dec 2017 |
|---|---|---|---|---|
| 84140306 | Portland General Electric Company | 500 | 500 | 500 |
| 84140319 | Portland General Electric Company | 2 | 2 | 2 |
| 85579909 | Portland General Electric Company | 3,300 | | |
| 85579921 | Portland General Electric Company | 28 | | |
| 85725066 | Portland General Electric Company | | 3300 | |
| 85725092 | Portland General Electric Company | | 40 | |
| 85902033 | Portland General Electric Company | | | 15 |
| 85938926 | Portland General Electric Company | | | 3300 |
| 85938933 | Portland General Electric Company | | | 40 |
| | **Total** | **3,830** | **3,842** | **3,857** |

***Schedule Page: 400.1 Line No.: 4 Column: g***

Long Term Firm Point-to-Point Reservations: Q1

| Reservation # | Customer | MW Granted Jan 2017 | MW Granted Feb 2017 | MW Granted Mar 2017 | Earliest Termination Date |
|---|---|---|---|---|---|
| 76059414 | Portland General Electric Company | 307 | 307 | 307 | 7/1/2022 |

***Schedule Page: 400.1 Line No.: 8 Column: g***

Long Term Firm Point-to-Point Reservations: Q2

| Reservation # | Customer | MW Granted Apr 2017 | MW Granted May 2017 | MW Granted Jun 2017 | Earliest Termination Date |
|---|---|---|---|---|---|
| 76059414 | Portland General Electric Company | 307 | 307 | 307 | 7/1/2022 |

***Schedule Page: 400.1 Line No.: 12 Column: g***

Long Term Firm Point-to-Point Reservations: Q3

| Reservation # | Customer | MW Granted Jul 2017 | MW Granted Aug 2017 | MW Granted Sep 2017 | Earliest Termination Date |
|---|---|---|---|---|---|
| 76059414 | Portland General Electric Company | 307 | 307 | 307 | 7/1/2022 |

***Schedule Page: 400.1 Line No.: 16 Column: g***

Long Term Firm Point-to-Point Reservations: Q4

| Reservation # | Customer | MW Granted Oct 2017 | MW Granted Nov 2017 | MW Granted Dec 2017 | Earliest Termination Date |
|---|---|---|---|---|---|
| 76059414 | Portland General Electric Company | 307 | 307 | 307 | 7/1/2022 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/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: PGE

| Line No. | Month (a) | Monthly Peak MW - Total (b) | Day of Monthly Peak (c) | Hour of Monthly Peak (d) | Imports into ISO/RTO (e) | Exports from ISO/RTO (f) | Through and Out Service (g) | Network Service Usage (h) | Point-to-Point Service Usage (i) | Total Usage (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 | | | | | | | | | |
| | | | | | | | | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

| Line No. | Item (a) | MegaWatt Hours (b) | Line No. | Item (a) | MegaWatt Hours (b) |
|---|---|---|---|---|---|
| 1 | SOURCES OF ENERGY | | 21 | DISPOSITION OF ENERGY | |
| 2 | Generation (Excluding Station Use): | | 22 | Sales to Ultimate Consumers (Including Interdepartmental Sales) | 17,754,280 |
| 3 | Steam | 3,343,848 | | | |
| 4 | Nuclear | | 23 | Requirements Sales for Resale (See instruction 4, page 311.) | |
| 5 | Hydro-Conventional | 1,773,522 | | | |
| 6 | Hydro-Pumped Storage | | 24 | Non-Requirements Sales for Resale (See instruction 4, page 311.) | 3,574,665 |
| 7 | Other | 7,869,712 | | | |
| 8 | Less Energy for Pumping | | 25 | Energy Furnished Without Charge | |
| 9 | Net Generation (Enter Total of lines 3 through 8) | 12,987,082 | 26 | Energy Used by the Company (Electric Dept Only, Excluding Station Use) | 26,450 |
| 10 | Purchases | 9,487,631 | 27 | Total Energy Losses | 1,189,113 |
| 11 | Power Exchanges: | | 28 | TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20) | 22,544,508 |
| 12 | Received | -1,350 | | | |
| 13 | Delivered | | | | |
| 14 | Net Exchanges (Line 12 minus line 13) | -1,350 | | | |
| 15 | Transmission For Other (Wheeling) | | | | |
| 16 | Received | 6,384,452 | | | |
| 17 | Delivered | 6,313,307 | | | |
| 18 | Net Transmission for Other (Line 16 minus line 17) | 71,145 | | | |
| 19 | Transmission By Others Losses | | | | |
| 20 | TOTAL (Enter Total of lines 9, 10, 14, 18 and 19) | 22,544,508 | | | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

| Line No. | Month | Total Monthly Energy | Monthly Non-Requirments Sales for Resale & Associated Losses | MONTHLY PEAK | | |
|---|---|---|---|---|---|---|
| | | | | Megawatts (See Instr. 4) | Day of Month | Hour |
| | (a) | (b) | (c) | (d) | (e) | (f) |
| 29 | January | 2,128,457 | 171,389 | 3,727 | 6 | 9 |
| 30 | February | 1,781,909 | 195,602 | 3,417 | 2 | 19 |
| 31 | March | 1,791,576 | 203,478 | 3,087 | 6 | 19 |
| 32 | April | 1,638,298 | 222,808 | 2,785 | 3 | 8 |
| 33 | May | 1,650,065 | 227,905 | 3,192 | 22 | 19 |
| 34 | June | 1,656,982 | 254,631 | 3,535 | 25 | 18 |
| 35 | July | 1,994,721 | 462,627 | 3,474 | 31 | 18 |
| 36 | August | 2,193,306 | 510,296 | 3,976 | 3 | 18 |
| 37 | September | 1,998,841 | 533,845 | 3,595 | 5 | 18 |
| 38 | October | 1,710,689 | 297,879 | 2,735 | 31 | 8 |
| 39 | November | 1,803,351 | 267,197 | 3,027 | 28 | 19 |
| 40 | December | 2,125,168 | 289,081 | 3,369 | 26 | 18 |
| 41 | TOTAL | 22,473,363 | 3,636,738 | | | |

**Schedule Page: 401 Line No.: 7 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, Other Generation includes 1,608,815 megawatt hours of net wind energy scheduled and delivered by Bonneville Power Administration (BPA) from PGE's Biglow Canyon Wind Farm and Tucannon River Wind Farm. Actual gross wind generation from the two wind farms was 1,643,732 megawatt hours.

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

| | |
|---|---|
| In-service production cost at 12/31/2017: | $928,176,702 |
| Total installed capacity: | 450 megawatts |
| Operations and maintenance expenses for 2017: | $15,678,481 |

The Tucannon River Wind Farm was placed in service on December 15, 2014. Key statistics include the following:

| | |
|---|---|
| In-service production cost at 12/31/2017: | $484,097,437 |
| Total installed capacity: | 267 megawatts |
| Operations and maintenance expenses for 2017: | $11,319,865 |

**Schedule Page: 401 Line No.: 27 Column: b**

PGE has ownership in a 5Mw storage battery (Salem Smart Power Center) with a FERC 101 Plant-in-service balance of $384,933 as of year end 2017, 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 2017 to FERC 584.1 - Operation of Energy Storage Equipment $552 and FERC 592.2 - Maintenance of Energy Storage Equipment $31,642. Line loss includes 0.6 MWh of Energy stored in this battery at year end.

**Schedule Page: 401 Line No.: 40 Column: c**

Line losses associated with Sales for Resale have been estimated. This note applies to column (c), lines 29 - 40.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## 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 (b) | Plant Name: Boardman (PGE Share) (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 | 577.90 |
| 6 | Net Peak Demand on Plant - MW (60 minutes) | 602 | 0 |
| 7 | Plant Hours Connected to Load | 3936 | 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 | 91 | 0 |
| 12 | Net Generation, Exclusive of Plant Use - KWh | 1576625000 | 1414549000 |
| 13 | Cost of Plant: Land and Land Rights | 939463 | 832853 |
| 14 | Structures and Improvements | 153762123 | 141154637 |
| 15 | Equipment Costs | 577527360 | 513716588 |
| 16 | Asset Retirement Costs | 49976652 | 44930644 |
| 17 | Total Cost | 782205598 | 700634722 |
| 18 | Cost per KW of Installed Capacity (line 17/5) Including | 1218.0093 | 1212.3806 |
| 19 | Production Expenses: Oper, Supv, & Engr | 2509752 | 2128679 |
| 20 | Fuel | 46444454 | 42287954 |
| 21 | Coolants and Water (Nuclear Plants Only) | 0 | 0 |
| 22 | Steam Expenses | 5418553 | 4740607 |
| 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 | 7416213 | 6609281 |
| 27 | Rents | 0 | 0 |
| 28 | Allowances | 0 | 0 |
| 29 | Maintenance Supervision and Engineering | 394160 | 358465 |
| 30 | Maintenance of Structures | 287662 | 247282 |
| 31 | Maintenance of Boiler (or reactor) Plant | 1511301 | 1322744 |
| 32 | Maintenance of Electric Plant | 13238820 | 11719765 |
| 33 | Maintenance of Misc Steam (or Nuclear) Plant | 508149 | 451366 |
| 34 | Total Production Expenses | 77729064 | 69866143 |
| 35 | Expenses per Net KWh | 0.0493 | 0.0494 |

| Line No. | Item (a) | (b) | | | (c) | | |
|---|---|---|---|---|---|---|---|
| 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 | 1031022 | 18609 | 0 | 0 | 0 | 0 |
| 39 | Avg Heat Cont - Fuel Burned (btu/indicate if nuclear) | 8656 | 138800 | 0 | 0 | 0 | 0 |
| 40 | Avg Cost of Fuel/unit, as Delvd f.o.b. during year | 42.438 | 80.036 | 0.000 | 0.000 | 0.000 | 0.000 |
| 41 | Average Cost of Fuel per Unit Burned | 45.047 | 76.299 | 0.000 | 0.000 | 0.000 | 0.000 |
| 42 | Average Cost of Fuel Burned per Million BTU | 2.602 | 13.088 | 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 | 10392.200 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## 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 | 1929299000 |
| 13 | Cost of Plant: Land and Land Rights | 0 | 3328862 |
| 14 | Structures and Improvements | 0 | 116843871 |
| 15 | Equipment Costs | 0 | 356111360 |
| 16 | Asset Retirement Costs | 0 | 22935683 |
| 17 | Total Cost | 0 | 499219776 |
| 18 | Cost per KW of Installed Capacity (line 17/5) Including | 0 | 1604.1767 |
| 19 | Production Expenses: Oper, Supv, & Engr | 0 | 399352 |
| 20 | Fuel | 0 | 31643179 |
| 21 | Coolants and Water (Nuclear Plants Only) | 0 | 0 |
| 22 | Steam Expenses | 0 | 2062902 |
| 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 | 2475846 |
| 27 | Rents | 0 | 56711 |
| 28 | Allowances | 0 | 0 |
| 29 | Maintenance Supervision and Engineering | 0 | 439595 |
| 30 | Maintenance of Structures | 0 | 767845 |
| 31 | Maintenance of Boiler (or reactor) Plant | 0 | 5851334 |
| 32 | Maintenance of Electric Plant | 0 | 1872567 |
| 33 | Maintenance of Misc Steam (or Nuclear) Plant | 0 | 844841 |
| 34 | Total Production Expenses | 0 | 46414172 |
| 35 | Expenses per Net KWh | 0.0000 | 0.0241 |

| Line No. | Item (a) | (b) | (b) | (b) | (c) | (c) | (c) |
|---|---|---|---|---|---|---|---|
| 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 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## 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: *Beaver* (d) | | | Plant Name: *Port Westward 1* (e) | | | Plant Name: *Coyote Springs* (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 |
| 610.90 | | | 483.30 | | | 271.20 | | | 5 |
| 574 | | | 434 | | | 270 | | | 6 |
| 2465 | | | 5759 | | | 5372 | | | 7 |
| 0 | | | 0 | | | 0 | | | 8 |
| 533 | | | 421 | | | 270 | | | 9 |
| 0 | | | 0 | | | 0 | | | 10 |
| 47 | | | 26 | | | 29 | | | 11 |
| 367952000 | | | 2127593000 | | | 1211241000 | | | 12 |
| 24473 | | | 24473 | | | 0 | | | 13 |
| 36265807 | | | 42041345 | | | 11505445 | | | 14 |
| 216022206 | | | 233098853 | | | 182359776 | | | 15 |
| 2941318 | | | 231072 | | | 113193 | | | 16 |
| 255253804 | | | 275395743 | | | 193978414 | | | 17 |
| 417.8324 | | | 569.8236 | | | 715.2596 | | | 18 |
| 292981 | | | 717478 | | | 272426 | | | 19 |
| 12333382 | | | 50290301 | | | 22349808 | | | 20 |
| 0 | | | 0 | | | 0 | | | 21 |
| 0 | | | 0 | | | 0 | | | 22 |
| 0 | | | 0 | | | 0 | | | 23 |
| 0 | | | 0 | | | 0 | | | 24 |
| 2534508 | | | 2773606 | | | 808168 | | | 25 |
| 2949138 | | | 1395810 | | | 628643 | | | 26 |
| 185039 | | | 24372 | | | 75131 | | | 27 |
| 0 | | | 0 | | | 0 | | | 28 |
| 738789 | | | 10278 | | | 2560 | | | 29 |
| 169819 | | | 34918 | | | 25757 | | | 30 |
| 0 | | | 0 | | | 0 | | | 31 |
| 6589165 | | | 7199491 | | | 4950370 | | | 32 |
| 391534 | | | 99121 | | | 27751 | | | 33 |
| 26184355 | | | 62545375 | | | 29140614 | | | 34 |
| 0.0712 | | | 0.0294 | | | 0.0241 | | | 35 |
| Gas | Oil | | Gas | Oil | | Gas | Oil | | 36 |
| Mcf's | Barrels | | Mcf's | Barrels | | Mcf's | Barrels | | 37 |
| 3792406 | 442 | 0 | 14772128 | 0 | 0 | 9166151 | 0 | 0 | 38 |
| 1019000 | 138690 | 0 | 1019000 | 138690 | 0 | 1019000 | 138690 | 0 | 39 |
| 2.221 | 0.000 | 0.000 | 2.620 | 0.000 | 0.000 | 1.802 | 0.000 | 0.000 | 40 |
| 3.614 | 208.999 | 0.000 | 3.488 | 0.000 | 0.000 | 3.827 | 0.000 | 0.000 | 41 |
| 3.545 | 35.948 | 0.000 | 3.422 | 0.000 | 0.000 | 3.754 | 0.000 | 0.000 | 42 |
| 0.037 | 0.000 | 0.000 | 0.024 | 0.000 | 0.000 | 0.029 | 0.000 | 0.000 | 43 |
| 10506.400 | 0.000 | 0.000 | 7077.600 | 0.000 | 0.000 | 7714.100 | 0.000 | 0.000 | 44 |

| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

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: *Port Westward 2* (d) | | | Plant Name: *Carty* (e) | | | Plant Name: (f) | | | Line No. |
|---|---|---|---|---|---|---|---|---|---|
| Reciprocating Engine | | | Gas & Steam Turbine | | | | | | 1 |
| Outdoor | | | Outdoor | | | | | | 2 |
| 2014 | | | 2016 | | | | | | 3 |
| 2014 | | | 2016 | | | | | | 4 |
| 225.00 | | | 503.00 | | | 0.00 | | | 5 |
| 224 | | | 482 | | | 0 | | | 6 |
| 2645 | | | 6191 | | | 0 | | | 7 |
| 0 | | | 0 | | | 0 | | | 8 |
| 225 | | | 0 | | | 0 | | | 9 |
| 0 | | | 0 | | | 0 | | | 10 |
| 0 | | | 22 | | | 0 | | | 11 |
| 144030000 | | | 2377392000 | | | 0 | | | 12 |
| 0 | | | 0 | | | 0 | | | 13 |
| 42352305 | | | 91013966 | | | 0 | | | 14 |
| 245647463 | | | 562276007 | | | 0 | | | 15 |
| 647461 | | | 4556945 | | | 0 | | | 16 |
| 288647229 | | | 657846918 | | | 0 | | | 17 |
| 1282.8766 | | | 1307.8468 | | | 0 | | | 18 |
| 6492 | | | 442819 | | | 0 | | | 19 |
| 6253975 | | | 50940551 | | | 0 | | | 20 |
| 0 | | | 0 | | | 0 | | | 21 |
| 0 | | | 0 | | | 0 | | | 22 |
| 0 | | | 0 | | | 0 | | | 23 |
| 0 | | | 0 | | | 0 | | | 24 |
| 279172 | | | 3603047 | | | 0 | | | 25 |
| 951445 | | | 1605719 | | | 0 | | | 26 |
| 28431 | | | 0 | | | 0 | | | 27 |
| 0 | | | 0 | | | 0 | | | 28 |
| 698 | | | 130800 | | | 0 | | | 29 |
| 11666 | | | 34578 | | | 0 | | | 30 |
| 0 | | | 0 | | | 0 | | | 31 |
| 1187957 | | | 9274548 | | | 0 | | | 32 |
| 34672 | | | 419566 | | | 0 | | | 33 |
| 8754508 | | | 66451628 | | | 0 | | | 34 |
| 0.0608 | | | 0.0280 | | | 0.0000 | | | 35 |
| Gas | Oil | | Gas | Oil | | | | | 36 |
| Mcf's | Barrels | | Mcf's | Barrels | | | | | 37 |
| 1538841 | 0 | 0 | 16481973 | 0 | 0 | 0 | 0 | 0 | 38 |
| 1019000 | 138690 | 0 | 1019000 | 138690 | 0 | 0 | 0 | 0 | 39 |
| 1.983 | 0.000 | 0.000 | 1.799 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 40 |
| 6.507 | 0.000 | 0.000 | 2.128 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 41 |
| 6.383 | 0.000 | 0.000 | 2.088 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 42 |
| 0.070 | 0.000 | 0.000 | 0.015 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 43 |
| 10891.100 | 0.000 | 0.000 | 7067.100 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 44 |

***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.

***Schedule Page: 402 Line No.: -1 Column: c***

Respondent is the principal owner and operator of the Boardman Plant. Installed capacity on line 5c represents 90% share. Reported here are the respondent's share of expenses incurred during the year and investment as of December 31, 2017, as appropriate. Details are reported in Page 402 col (b).

***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: 403.1 Line No.: -1 Column: e***

On July 29th, 2016 the PGE Carty Generating Plant was declared in-service and available to generate electricity.

***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 used 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 1 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.

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## 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<br>(a) | FERC Licensed Project No. 0<br>Plant Name:<br>(b) | FERC Licensed Project No. 2195<br>Plant Name: Faraday<br>(c) |
|---|---|---|---|
| | | | |
| | | | |
| 1 | Kind of Plant (Run-of-River or Storage) | | Run-of-River;Storage |
| 2 | Plant Construction type (Conventional or Outdoor) | | Conventional;Outdoor |
| 3 | Year Originally Constructed | | 1907 |
| 4 | Year Last Unit was Installed | | 1958 |
| 5 | Total installed cap (Gen name plate Rating in MW) | 0.00 | 36.81 |
| 6 | Net Peak Demand on Plant-Megawatts (60 minutes) | 0 | 47 |
| 7 | Plant Hours Connect to Load | 0 | 8,760 |
| 8 | Net Plant Capability (in megawatts) | | |
| 9 | (a) Under Most Favorable Oper Conditions | 0 | 46 |
| 10 | (b) Under the Most Adverse Oper Conditions | 0 | 5 |
| 11 | Average Number of Employees | 0 | 51 |
| 12 | Net Generation, Exclusive of Plant Use - Kwh | 0 | 174,137,000 |
| 13 | Cost of Plant | | |
| 14 | Land and Land Rights | 0 | 33,434 |
| 15 | Structures and Improvements | 0 | 7,062,823 |
| 16 | Reservoirs, Dams, and Waterways | 0 | 27,511,074 |
| 17 | Equipment Costs | 0 | 9,558,393 |
| 18 | Roads, Railroads, and Bridges | 0 | 2,342,099 |
| 19 | Asset Retirement Costs | 0 | 90 |
| 20 | TOTAL cost (Total of 14 thru 19) | 0 | 46,507,913 |
| 21 | Cost per KW of Installed Capacity (line 20 / 5) | 0.0000 | 1,263.4587 |
| 22 | Production Expenses | | |
| 23 | Operation Supervision and Engineering | 0 | 308,781 |
| 24 | Water for Power | 0 | 65,206 |
| 25 | Hydraulic Expenses | 0 | 1,166,793 |
| 26 | Electric Expenses | 0 | 311,892 |
| 27 | Misc Hydraulic Power Generation Expenses | 0 | 1,050,465 |
| 28 | Rents | 0 | 120,157 |
| 29 | Maintenance Supervision and Engineering | 0 | 503,993 |
| 30 | Maintenance of Structures | 0 | 0 |
| 31 | Maintenance of Reservoirs, Dams, and Waterways | 0 | 21,048 |
| 32 | Maintenance of Electric Plant | 0 | 180,462 |
| 33 | Maintenance of Misc Hydraulic Plant | 0 | 686,708 |
| 34 | Total Production Expenses (total 23 thru 33) | 0 | 4,415,505 |
| 35 | Expenses per net KWh | 0.0000 | 0.0254 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## 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 (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 | 73.20 |
| 6 | Net Peak Demand on Plant-Megawatts (60 minutes) | 114 | 0 |
| 7 | Plant Hours Connect to Load | 8,282 | 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 | 444,848,000 | 296,579,000 |
| 13 | Cost of Plant | | |
| 14 | Land and Land Rights | 3,681,439 | 2,454,415 |
| 15 | Structures and Improvements | 9,138,027 | 6,097,327 |
| 16 | Reservoirs, Dams, and Waterways | 15,688,182 | 10,684,259 |
| 17 | Equipment Costs | 10,352,209 | 6,913,997 |
| 18 | Roads, Railroads, and Bridges | 3,242,001 | 2,167,121 |
| 19 | Asset Retirement Costs | 52 | 52 |
| 20 | TOTAL cost (Total of 14 thru 19) | 42,101,910 | 28,317,171 |
| 21 | Cost per KW of Installed Capacity (line 20 / 5) | 382.0500 | 386.8466 |
| 22 | Production Expenses | | |
| 23 | Operation Supervision and Engineering | 251,691 | 167,352 |
| 24 | Water for Power | 808,788 | 92,379 |
| 25 | Hydraulic Expenses | 2,678,099 | 1,909,877 |
| 26 | Electric Expenses | 221,448 | 138,620 |
| 27 | Misc Hydraulic Power Generation Expenses | 456,043 | 261,789 |
| 28 | Rents | 9,882 | 4,283 |
| 29 | Maintenance Supervision and Engineering | 123,911 | 34,353 |
| 30 | Maintenance of Structures | 0 | 0 |
| 31 | Maintenance of Reservoirs, Dams, and Waterways | 32,218 | 32,218 |
| 32 | Maintenance of Electric Plant | 207,841 | 98,266 |
| 33 | Maintenance of Misc Hydraulic Plant | 146,371 | 58,616 |
| 34 | Total Production Expenses (total 23 thru 33) | 4,936,292 | 2,797,753 |
| 35 | Expenses per net KWh | 0.0111 | 0.0094 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

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<br>Plant Name: North Fork<br>(d) | FERC Licensed Project No. 2195<br>Plant Name: River Mill<br>(e) | FERC Licensed Project No. 2195<br>Plant Name: Oak Grove<br>(f) | Line No. |
|---|---|---|---|
| | | | |
| | | | |
| Run-of-River | Run-of-River | Run-of-River;Stor | 1 |
| Outdoor | Conventional | Conventional | 2 |
| 1958 | 1911 | 1924 | 3 |
| 1958 | 1952 | 1931 | 4 |
| 50.25 | 20.60 | 51.00 | 5 |
| 57 | 38 | 41 | 6 |
| 8,760 | 8,757 | 8,758 | 7 |
| | | | 8 |
| 58 | 25 | 44 | 9 |
| 7 | 4 | 19 | 10 |
| 0 | 0 | 7 | 11 |
| 227,071,000 | 110,190,000 | 209,248,000 | 12 |
| | | | 13 |
| 377,100 | 86,408 | 9,457 | 14 |
| 9,070,502 | 6,683,329 | 15,098,214 | 15 |
| 86,490,232 | 55,505,213 | 26,004,315 | 16 |
| 13,793,585 | 8,560,800 | 12,904,171 | 17 |
| 2,767,780 | 421,796 | 3,856,282 | 18 |
| 6 | 64 | 2,122 | 19 |
| 112,499,205 | 71,257,610 | 57,874,561 | 20 |
| 2,238.7901 | 3,459.1073 | 1,134.7953 | 21 |
| | | | 22 |
| 22,457 | 12,821 | 31,304 | 23 |
| 51,246 | 42,408 | 69,069 | 24 |
| 581,690 | 235,055 | 1,239,752 | 25 |
| 181,325 | 51,811 | 88,504 | 26 |
| 561,132 | 190,831 | 277,515 | 27 |
| 35,221 | 0 | 520,756 | 28 |
| 83,765 | 78,816 | 213,243 | 29 |
| 0 | 0 | 8,691 | 30 |
| 48,666 | 15,844 | 200,664 | 31 |
| 33,227 | 178,272 | 229,153 | 32 |
| 234,833 | 73,296 | 160,141 | 33 |
| 1,833,562 | 879,154 | 3,038,792 | 34 |
| 0.0081 | 0.0080 | 0.0145 | 35 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## 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<br>Plant Name: Round Butte<br>(d) | FERC Licensed Project No. 2030<br>Plant Name: Round Butte<br>(e) | FERC Licensed Project No. 2233<br>Plant Name: Sullivan<br>(f) | Line No. |
|---|---|---|---|
| | | | |
| | | | |
| Storage | Storage | Run-of-River | 1 |
| Conventional | Conventional | Conventional | 2 |
| 1964 | 1964 | 1895 | 3 |
| 1964 | 1964 | 1953 | 4 |
| 372.50 | 248.33 | 15.40 | 5 |
| 342 | 0 | 18 | 6 |
| 8,494 | 0 | 4,988 | 7 |
| | | | 8 |
| 345 | 0 | 18 | 9 |
| 192 | 0 | 7 | 10 |
| 44 | 0 | 1 | 11 |
| 1,036,028,000 | 690,721,000 | 65,576,000 | 12 |
| | | | 13 |
| 3,726,481 | 2,521,011 | 572,077 | 14 |
| 18,066,313 | 12,037,076 | 18,209,506 | 15 |
| 169,458,860 | 110,658,527 | 32,250,537 | 16 |
| 36,350,309 | 24,388,832 | 13,936,088 | 17 |
| 2,489,334 | 1,684,933 | 0 | 18 |
| 164 | 164 | 2,630 | 19 |
| 230,091,461 | 151,290,543 | 64,970,838 | 20 |
| 617.6952 | 609.2318 | 4,218.8856 | 21 |
| | | | 22 |
| 310,113 | 207,031 | 5,966 | 23 |
| 1,101,696 | 226,086 | 35,113 | 24 |
| 2,443,895 | 1,504,957 | 57,058 | 25 |
| 330,855 | 229,622 | 69,815 | 26 |
| 839,114 | 601,692 | 230,065 | 27 |
| 27,447 | 20,604 | 0 | 28 |
| 256,550 | 147,091 | 18,709 | 29 |
| 0 | 0 | -10,258 | 30 |
| 184,432 | 184,432 | 58,392 | 31 |
| 522,847 | 388,921 | 168,617 | 32 |
| 438,681 | 331,426 | 19,674 | 33 |
| 6,455,630 | 3,841,862 | 653,151 | 34 |
| 0.0062 | 0.0056 | 0.0100 | 35 |

***Schedule Page: 406.1 Line No.: -2 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.: -2 Column: c***

Jointly owned. Installed capacity on line 5 represents 66.67% share. Details reported on Page 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.: -2 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.: -2 Column: e***

Jointly owned. Installed capacity on line 5 represents 66.67% share. Details reported on Page 407.1, 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 geographically close in 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***

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

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## 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 Demaind 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) | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

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.<br>Plant Name:<br>(c) | FERC Licensed Project No.<br>Plant Name:<br>(d) | FERC Licensed Project No.<br>Plant Name:<br>(e) | Line No. |
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| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

| Line No. | Name of Plant<br>(a) | Year Orig. Const.<br>(b) | Installed Capacity Name Plate Rating (In MW)<br>(c) | Net Peak Demand MW (60 min.)<br>(d) | Net Generation Excluding Plant Use<br>(e) | Cost of Plant<br>(f) |
|---|---|---|---|---|---|---|
| 1 | Maclaren | 1999 | 0.50 | 0.4 | 7 | 133,799 |
| 2 | Oregon Military Dept/A.F.R.C | 2001 | 1.60 | 1.6 | 143 | 186,058 |
| 3 | US Bank Corp Columbia Center | 2001 | 6.40 | 6.2 | 882 | 488,057 |
| 4 | Portland State University | 2004 | 2.80 | 2.8 | 53 | 261,732 |
| 5 | Oregon Military Joint Forces HQ | 2005 | 1.60 | 1.6 | 52 | 191,439 |
| 6 | Stimson Lumber | 2005 | 0.57 | 0.5 | 19 | 159,546 |
| 7 | FORTIX (ViaWest) | 2005 | 9.00 | 8.0 | 1,393 | 629,142 |
| 8 | Skyline | 2005 | 2.00 | 1.8 | 85 | 201,526 |
| 9 | Tri-Quint | 2005 | 0.60 | 0.5 | 13 | 109,968 |
| 10 | NCCWC- Filter Plant | 2005 | 2.00 | 1.8 | 57 | 122,958 |
| 11 | PCC Structurals | 2005 | 1.00 | 0.9 | 27 | 113,874 |
| 12 | Providence Portland Medical Center | 2005 | 6.00 | 5.4 | 561 | 265,383 |
| 13 | Salem Hospital | 2006 | 8.00 | 7.2 | 683 | 269,108 |
| 14 | Sunrise Water Authority Pump Station | 2006 | 1.25 | 1.1 | 22 | 88,272 |
| 15 | Providence Newberg Hospital | 2006 | 1.50 | 1.4 | 83 | 156,833 |
| 16 | Sungard DSG | 2006 | 2.00 | 1.8 | 35 | 331,845 |
| 17 | Kaiser Sunnyside Hospital | 2007 | 4.50 | 4.0 | 599 | 352,752 |
| 18 | Newberg Waste Water Treatment Plant | 2008 | 2.00 | 1.8 | 61 | 154,458 |
| 19 | Xerox Corp | 2007 | 4.00 | 3.6 | 199 | 380,259 |
| 20 | Newberg Water Treatment Plant | 2007 | 1.00 | 0.9 | 22 | 78,159 |
| 21 | MEMC (Solaicx) | 2008 | 1.00 | 0.9 | 3 | 62,963 |
| 22 | Solar World | 2008 | 3.00 | 2.7 | 70 | 219,984 |
| 23 | Oregon Dept of Admin Serv - Data Center | 2010 | 2.00 | 2.3 | 86 | 277,254 |
| 24 | Sanyo | 2010 | 1.00 | 0.9 | 16 | 43,144 |
| 25 | Sysco Foods | 2010 | 2.00 | 1.8 | 36 | 184,779 |
| 26 | Clackamas Intertie 2 | 2012 | 0.60 | 0.5 | 4 | 155,832 |
| 27 | Dawson Creek | 2012 | 0.80 | 0.7 | 14 | 95,706 |
| 28 | Kaiser Westside Hospital | 2012 | 4.00 | 3.6 | 369 | 408,830 |
| 29 | North Plains Pump Station | 2012 | 0.80 | 0.7 | 16 | 53,132 |
| 30 | Oak Lodge Sanitary District | 2012 | 2.00 | 1.8 | 43 | 229,144 |
| 31 | Oregon Dept of Admin Serv - Revenue Bldg | 2012 | 1.50 | 1.4 | 26 | 284,255 |
| 32 | Oregon State Hospital | 2012 | 4.00 | 3.6 | 251 | 172,879 |
| 33 | Portland Service Center | 2012 | 0.50 | 0.5 | 10 | 322,856 |
| 34 | Sandy Highschool | 2012 | 1.25 | 1.1 | 20 | 179,894 |
| 35 | TATA Communications - Hillsboro | 2012 | 4.50 | 3.2 | 156 | 328,979 |
| 36 | Tri-City Wastewater Treatment Plant | 2012 | 2.50 | 2.3 | 42 | 161,695 |
| 37 | TATA Communications - Portland | 2013 | 6.60 | 5.4 | 401 | 612,983 |
| 38 | City of Hillsboro Crandall Reservoir | 2013 | 0.80 | 0.7 | 15 | 105,854 |
| 39 | East County Courts | 2013 | 1.50 | 1.4 | 25 | 316,848 |
| 40 | City of Portland-Columbia Blvd WWTP | 2013 | 1.00 | 0.9 | 16 | 162,234 |
| 41 | Food Services of America | 2013 | 2.00 | 1.8 | 27 | 229,875 |
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| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

| 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 | Avery DSG | 2014 | 0.80 | 0.7 | 13 | 263,782 |
| 2 | Carver (Readiness Center) DSG | 2014 | 2.00 | 1.8 | 86 | 818,635 |
| 3 | Juvenile Justice Center | 2014 | 0.70 | 0.7 | 7 | 171,380 |
| 4 | Clackamas River Water DSG | 2014 | 2.00 | 1.8 | 46 | 383,436 |
| 5 | Joint Water Commission | 2015 | 5.00 | 4.5 | 207 | 190,302 |
| 6 | Wapato Jail | 2015 | 1.50 | 1.4 | 6 | 416,991 |
| 7 | McLane Foodservice | 2016 | 1.50 | 1.4 | 25 | 181,242 |
| 8 | ViaWest Brookwood | 2016 | 5.00 | 4.4 | 449 | 170,639 |
| 9 | World Trade Center | 2017 | 3.20 | 2.9 | 291 | 724,643 |
| 10 | Washington County Jail | 2017 | 1.50 | 1.4 | 44 | 325,268 |
| 11 | OHSU - VGTI | 2017 | 1.50 | 1.4 | | 278,374 |
| 12 | Solar | 2014 | 6.52 | 6.5 | 4 | 3,702,036 |
| 13 | Total | | | | | 16,911,016 |
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| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

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 Fuel (i) | Production Expenses Maintenance (j) | Kind of Fuel (k) | Fuel Costs (in cents (per Million Btu) (l) | Line No. |
|---|---|---|---|---|---|---|
| 267,597 | | 3,179 | 12,573 | diesel-low s | 1,629 | 1 |
| 116,286 | | 3,621 | 20,581 | diesel-low s | 1,414 | 2 |
| 70,836 | | | 102,565 | diesel-low s | 1,450 | 3 |
| 93,476 | | 14,804 | 39,529 | diesel-low s | 1,421 | 4 |
| 119,650 | | | 70,689 | diesel-low s | 1,450 | 5 |
| 282,382 | | 2,814 | 8,256 | diesel-low s | 1,386 | 6 |
| 69,905 | | 30,754 | 98,340 | diesel-low s | 1,529 | 7 |
| 100,763 | | 5,579 | 21,890 | diesel-low s | 1,236 | 8 |
| 183,279 | | 576 | 6,366 | diesel-low s | 2,029 | 9 |
| 61,479 | | 4,885 | 8,342 | diesel-low s | 1,393 | 10 |
| 113,874 | | 1,750 | 3,946 | diesel-low s | 1,686 | 11 |
| 44,231 | | 36,406 | 38,992 | diesel-low s | 1,300 | 12 |
| 33,638 | | 19,091 | 32,228 | diesel-low s | 1,350 | 13 |
| 70,617 | | 4,279 | 28,768 | diesel-low s | 1,414 | 14 |
| 104,555 | | 9,802 | 19,173 | diesel-low s | 1,621 | 15 |
| 165,922 | | 5,390 | 9,659 | diesel-low s | 1,407 | 16 |
| 78,389 | | 45,783 | 17,866 | diesel-low s | 1,600 | 17 |
| 77,229 | | 9,876 | 28,455 | diesel-low s | 1,671 | 18 |
| 95,065 | | 11,910 | 16,386 | diesel-low s | 1,393 | 19 |
| 78,159 | | 2,572 | 15,177 | diesel-low s | 1,700 | 20 |
| 62,963 | | | 13,877 | diesel-low s | 1,450 | 21 |
| 73,328 | | 2,966 | 21,636 | diesel-low s | 1,614 | 22 |
| 106,636 | | 10,541 | 28,582 | diesel-low s | 1,736 | 23 |
| 43,144 | | 1,319 | 4,873 | diesel-low s | 1,579 | 24 |
| 92,390 | | 5,351 | 8,520 | diesel-low s | 1,479 | 25 |
| 259,720 | | | 4,971 | diesel-low s | 1,450 | 26 |
| 119,632 | | 4,113 | 9,828 | diesel-low s | 1,286 | 27 |
| 102,207 | | 21,237 | 52,946 | diesel-low s | 1,200 | 28 |
| 66,415 | | 2,585 | 7,902 | diesel-low s | 1,307 | 29 |
| 114,572 | | 4,716 | 12,311 | diesel-low s | 1,743 | 30 |
| 189,503 | | 3,297 | 12,158 | diesel-low s | 1,279 | 31 |
| 43,220 | | | 73,639 | diesel-low s | 1,450 | 32 |
| 645,711 | | | 26,618 | diesel-low s | 1,450 | 33 |
| 143,915 | | 2,982 | 5,694 | diesel-low s | 1,643 | 34 |
| 92,410 | | | 16,459 | diesel-low s | 1,450 | 35 |
| 64,678 | | 2,737 | 6,619 | diesel-low s | 2,029 | 36 |
| 92,876 | | 26,968 | 110,964 | diesel-low s | 1,293 | 37 |
| 132,317 | | | 14,633 | diesel-low s | 1,450 | 38 |
| 211,232 | | 2,409 | 24,760 | diesel-low s | 1,379 | 39 |
| 162,234 | | 3,038 | 22,519 | diesel-low s | 1,514 | 40 |
| 114,938 | | | 7,910 | diesel-low s | 1,450 | 41 |
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| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## 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 Fuel (i) | Production Expenses Maintenance (j) | Kind of Fuel (k) | Fuel Costs (in cents (per Million Btu) (l) | Line No. |
|---|---|---|---|---|---|---|
| 329,728 | | | 14,608 | diesel-low s | 1,450 | 1 |
| 409,317 | | | 43,812 | diesel-low s | 1,450 | 2 |
| 228,507 | | | 15,703 | diesel-low s | 1,450 | 3 |
| 191,718 | | 4,919 | 7,569 | diesel-low s | 1,450 | 4 |
| 38,060 | | | 22,770 | diesel-low s | 1,450 | 5 |
| 277,994 | | | 5,859 | diesel-low s | 1,450 | 6 |
| 120,828 | | 3,125 | 16,189 | diesel-low s | 1,329 | 7 |
| 34,128 | | 28,245 | 47,462 | diesel-low s | 1,371 | 8 |
| 226,451 | | 2,187 | 39,845 | diesel-low s | 1,286 | 9 |
| 216,845 | | 8,790 | 14,215 | diesel-low s | 1,379 | 10 |
| 185,583 | | | | diesel-low s | | 11 |
| 567,971 | | | 29,626 | solar | | 12 |
| | | 354,596 | 1,342,398 | | | 13 |
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| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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 From (a) | DESIGNATION To (b) | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c) | VOLTAGE (KV) Designed (d) | Type of Supporting Structure (e) | LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f) | LENGTH (Pole miles) On Structures of Another Line (g) | Number Of Circuits (h) |
|---|---|---|---|---|---|---|---|---|
| 1 | 500KV LINES | | | | | | | |
| 2 | GRIZZLY | ROUND BUTTE | 500.00 | 500.00 | ST. TOWER | 15.60 | | 1 |
| 3 | GRIZZLY | MALIN | 500.00 | 500.00 | ST. TOWER | 178.50 | | 1 |
| 4 | JOHN DAY | GRIZZLY '1' | 500.00 | 500.00 | | | | 1 |
| 5 | JOHN DAY | GRIZZLY '2' | 500.00 | 500.00 | | | | 1 |
| 6 | MISCELLANEOUS | MISCELLANEOUS | 500.00 | | | | | |
| 7 | CARTY | GRASSLAND | 500.00 | 500.00 | ST. TOWER | 0.75 | | |
| 8 | GRASSLAND | BPA SLATT | 500.00 | 500.00 | ST.TOWER | 16.82 | | |
| 9 | BOARDMAN | GRASSLAND | 500.00 | 500.00 | ST. TOWER | 0.94 | | 1 |
| 10 | COYOTE SPRINGS | BPA SLATT | 500.00 | 500.00 | | | | 2 |
| 11 | COLSTRIP PROJECT: | | | | | | | |
| 12 | COLSTRIP SWYD. | BROADVIEW 'A' | 500.00 | 500.00 | ST. TOWER | | 112.30 | 1 |
| 13 | COLSTRIP SWYD. | BROADVIEW 'B' | 500.00 | 500.00 | ST. TOWER | | 115.80 | 1 |
| 14 | BROADVIEW SWYD. | TOWNSEND 'A' | 500.00 | 500.00 | ST. TOWER | | 133.40 | 1 |
| 15 | BROADVIEW SWYD. | TOWNSEND 'B' | 500.00 | 500.00 | ST. TOWER | | 133.40 | 1 |
| 16 | Colstrip Project Costs | Project Lines | | | | | | |
| 17 | Tot 500KV Line Expenses | | | | | | | |
| 18 | | | | | | | | |
| 19 | BIGLOW CANYON WF | JOHN DAY | 230.00 | 230.00 | | | | 1 |
| 20 | TUCANNON WF | CENTRAL FERRY BPA | 230.00 | 230.00 | H-WOOD | 20.70 | | 1 |
| 21 | | | | | | | | |
| 22 | PELTON 230KV PROJECT | | | | | | | |
| 23 | PELTON | ROUND BUTTE | 230.00 | 230.00 | H-WOOD | 7.87 | | 1 |
| 24 | | | | | | | | |
| 25 | NON PROJECT 230KV: | | | | | | | |
| 26 | BETHEL | ROUND BUTTE | 230.00 | 230.00 | H-WOOD | 53.85 | | 1 |
| 27 | | | 230.00 | 230.00 | ST. TOWER | 44.85 | | 1 |
| 28 | ROUND BUTTE | BPA REDMOND | 230.00 | 230.00 | H-WOOD | 23.58 | | 1 |
| 29 | BETHEL | BPA TIE (SANTIAM) | 230.00 | 230.00 | H-WOOD | 3.64 | | 1 |
| 30 | BETHEL | McLOUGHLIN | 230.00 | 230.00 | H-WOOD | 35.57 | | 1 |
| 31 | CARVER | GRESHAM | 230.00 | 230.00 | H-WOOD | 7.17 | | 1 |
| 32 | McLOUGHLIN | CARVER #1 | 230.00 | 230.00 | H-WOOD | 4.95 | | 1 |
| 33 | McLOUGHLIN | CARVER #2 | 230.00 | 230.00 | ST. MONOP | 4.88 | | 1 |
| 34 | BPA KEELER | ST. MARY'S W. | 230.00 | 230.00 | H-WOOD | 2.89 | | 1 |
| 35 | | | 230.00 | 230.00 | ST. TOWER | 3.78 | | 2 |
| 36 | | | | | TOTAL | 611.10 | 536.65 | 58 |

| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

## TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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 From (a) | DESIGNATION To (b) | VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c) | VOLTAGE (KV) Designed (d) | Type of Supporting Structure (e) | LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f) | LENGTH (Pole miles) On Structures of Another Line (g) | Number Of Circuits (h) |
|---|---|---|---|---|---|---|---|---|
| 1 | BLUE LAKE | TROUTDALE BPA | 230.00 | 230.00 | H-WOOD | 0.80 | | 1 |
| 2 | | | 230.00 | 230.00 | ST. MONOP | 0.58 | | 1 |
| 3 | PEARL BPA | SHERWOOD | 230.00 | 230.00 | ST. TOWER | | 4.72 | 2 |
| 4 | | | 230.00 | 230.00 | ST. TOWER | 0.16 | | 1 |
| 5 | GRESHAM | LINNEMAN | 230.00 | 230.00 | ST. TOWER | 0.31 | | 1 |
| 6 | McLOUGHLIN | SHERWOOD | 230.00 | 230.00 | ST. TOWER | 11.51 | | 1 |
| 7 | | | 230.00 | 230.00 | H-TOWER | 0.60 | | 1 |
| 8 | NON PROJECT 230KV | | | | | | | |
| 9 | McLOUGHLIN | SHERWOOD | 230.00 | 230.00 | ST. TOWER | | 4.40 | 2 |
| 10 | ST. MARY'S W. | MURRAYHILL | 230.00 | 230.00 | ST. TOWER | 5.92 | | 1 |
| 11 | HORIZON | KEELER BPA | 230.00 | 230.00 | ST. MONOP | 1.47 | | 1 |
| 12 | MURRAYHILL | SHERWOOD | 230.00 | 230.00 | ST. TOWER | 5.68 | | 2 |
| 13 | PORT WESTWARD | TROJAN #1 | 230.00 | 230.00 | ST. MONOP | 18.78 | | 1 |
| 14 | PORT WESTWARD | TROJAN #2 | 230.00 | 230.00 | ST. MONOP | 9.39 | | 1 |
| 15 | TROJAN | ST. MARY'S W. | 230.00 | 230.00 | H-WOOD | 0.10 | | 1 |
| 16 | | | 230.00 | 230.00 | ST. TOWER | 8.07 | | 1 |
| 17 | | | | | ST.TOWER | | 32.20 | 1 |
| 18 | TROJAN | RIVERGATE | 230.00 | 230.00 | ST. TOWER | 32.20 | | 2 |
| 19 | | | 230.00 | 230.00 | ST. TOWER | 2.88 | | 2 |
| 20 | | | | | | | | |
| 21 | Tot Nonproj 230kv Costs | | | | | | | |
| 22 | | | | | | | | |
| 23 | GRESHAM | TROUTDALE BPA | 230.00 | 230.00 | ST. TOWER | | 0.43 | 1 |
| 24 | BOARDMAN | PPL DALREED | 230.00 | 230.00 | H-WOOD | 16.76 | | 1 |
| 25 | | | | | | | | |
| 26 | Tot 230KV LINE EXPENSES | | | | | | | |
| 27 | | | | | | | | |
| 28 | PROJECT 115 KV LINES | | | | | | | |
| 29 | FARADAY | MCLOUGHLIN | 115.00 | 115.00 | H-WOOD | 14.70 | | 1 |
| 30 | NORTH FORK | FARADAY | 115.00 | 115.00 | H-WOOD | 2.79 | | 1 |
| 31 | OAK GROVE | FARADAY | 115.00 | 115.00 | DC LATTICE | 18.68 | | 2 |
| 32 | OAK GROVE | MCLOUGHLIN | 115.00 | 115.00 | H-WOOD | 14.70 | | 2 |
| 33 | | | 115.00 | 115.00 | DC LATTICE | 18.68 | | 2 |
| 34 | Tot 115KV LINE EXPENSES | | | | | | | |
| 35 | | | | | | | | |
| 36 | | | | | TOTAL | 611.10 | 536.65 | 58 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## 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) Land (j) | Construction and Other Costs (k) | Total Cost (l) | EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m) | Maintenance Expenses (n) | Rents (o) | Total Expenses (p) | Line No. |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | | 1 |
| 1780MCMACSR | 50,953 | 1,645,820 | 1,696,773 | | | | | 2 |
| 1780MCMACSR | 275,427 | 17,485,375 | 17,760,802 | | | | | 3 |
| | | 148,889 | 148,889 | | | | | 4 |
| | | 148,889 | 148,889 | | | | | 5 |
| | 5,904 | | 5,904 | | | | | 6 |
| 1780MCMACSR | | 10,355,181 | 10,355,181 | | | | | 7 |
| 1780MCMACSR | | | | | | | | 8 |
| 1780MCMACSR | | 6,353,549 | 6,353,549 | | | | | 9 |
| | | 3,624,934 | 3,624,934 | | | | | 10 |
| | | | | | | | | 11 |
| | | | | | | | | 12 |
| | | | | | | | | 13 |
| | | | | | | | | 14 |
| | | | | | | | | 15 |
| | 1,194,326 | 43,101,062 | 44,295,388 | | | | | 16 |
| | | | | 1,614,390 | 513,098 | 947,879 | 3,075,367 | 17 |
| | | | | | | | | 18 |
| | | 3,040,852 | 3,040,852 | | | | | 19 |
| 795KCMAAC | | 1,956,263 | 1,956,263 | | | | | 20 |
| | | | | | | | | 21 |
| | | | | | | | | 22 |
| 795MCMACSR | 7,579 | 356,927 | 364,506 | | | | | 23 |
| | | | | | | | | 24 |
| | | | | | | | | 25 |
| 1272MCMACSR | | | | | | | | 26 |
| 1272MCMACSR | | | | | | | | 27 |
| 795MCMACSR | | | | | | | | 28 |
| 795MCMACSR | | | | | | | | 29 |
| 1272MCMACSR | | | | | | | | 30 |
| 1272MCMAAC | | | | | | | | 31 |
| 1272MCMAAC | | | | | | | | 32 |
| 1272MCMACSS | | | | | | | | 33 |
| 1590MCMACSRTW | | | | | | | | 34 |
| 1590MCMACSRTW | | | | | | | | 35 |
| | 10,552,540 | 160,220,718 | 170,773,258 | 2,622,882 | 852,597 | 872,737 | 4,348,216 | 36 |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

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 | COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) | | | EXPENSES, EXCEPT DEPRECIATION AND TAXES | | | | Line No. |
|---|---|---|---|---|---|---|---|---|
| (i) | Land (j) | Construction and Other Costs (k) | Total Cost (l) | Operation Expenses (m) | Maintenance Expenses (n) | Rents (o) | Total Expenses (p) | |
| 1780MCMACSR | | | | | | | | 1 |
| 1780MCMACSR | | | | | | | | 2 |
| 2388MCMAACTW | | | | | | | | 3 |
| 2388MCMAACTW | | | | | | | | 4 |
| 1272MCMAAC | | | | | | | | 5 |
| 1272MCMAAC | | | | | | | | 6 |
| 1780MCMACSR | | | | | | | | 7 |
| | | | | | | | | 8 |
| 1272MCMAAC | | | | | | | | 9 |
| 1272MCMAAC | | | | | | | | 10 |
| 1272MCMACSS | | | | | | | | 11 |
| 1272MCMAAC | | | | | | | | 12 |
| 2156MCMACSS | | | | | | | | 13 |
| 2156MCMACSS | | | | | | | | 14 |
| 1272MCMAAC | | | | | | | | 15 |
| 1590MCMAAC | | | | | | | | 16 |
| 1590MCMAAC | | | | | | | | 17 |
| 1590MCMAAC | | | | | | | | 18 |
| 1272MCMACSR | | | | | | | | 19 |
| | | | | | | | | 20 |
| | 8,863,277 | 68,156,961 | 77,020,238 | | | | | 21 |
| | | | | | | | | 22 |
| 954KCMACSR | | | | | | | | 23 |
| 795KCMAAC | | 976,430 | 976,430 | | | | | 24 |
| | | | | | | | | 25 |
| | | | | 1,007,864 | 339,287 | -143,520 | 1,203,631 | 26 |
| | | | | | | | | 27 |
| | | | | | | | | 28 |
| 795KCMACSR | | 867,996 | 867,996 | | | | | 29 |
| 556KCMACSR | 120,302 | 621,351 | 741,653 | | | | | 30 |
| 250CU | 12,477 | 503,937 | 516,414 | | | | | 31 |
| 795KCMACSR | | | | | | | | 32 |
| 250CU | 22,295 | 876,302 | 898,597 | | | | | 33 |
| | | | | 628 | 212 | 68,378 | 69,218 | 34 |
| | | | | | | | | 35 |
| | 10,552,540 | 160,220,718 | 170,773,258 | 2,622,882 | 852,597 | 872,737 | 4,348,216 | 36 |

**Schedule Page: 422 Line No.: 4 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.: 5 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.: 9 Column: a**

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

**Schedule Page: 422 Line No.: 10 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.: 11 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.: 17 Column: a**

Represents perpetual leases for transmission lines PGE has with the Bonneville Power Administration and for payments made to the FERC per Part 11 - Annual Charges under Part 1 of the Federal Power Act for use of government land as it pertains to transmission lines.

**Schedule Page: 422 Line No.: 19 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.: 23 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.: 3 Column: a**

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

**Schedule Page: 422.1 Line No.: 23 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**

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

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

| Line No. | LINE DESIGNATION | | Line Length in Miles | SUPPORTING STRUCTURE | | CIRCUITS PER STRUCTURE | |
|---|---|---|---|---|---|---|---|
| | From (a) | To (b) | (c) | Type (d) | Average Number per Miles (e) | Present (f) | Ultimate (g) |
| 1 | No Additions in 2017 | | | | | | |
| 2 | | | | | | | |
| 3 | | | | | | | |
| 4 | | | | | | | |
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| 41 | | | | | | | |
| 42 | | | | | | | |
| 43 | | | | | | | |
| 44 | TOTAL | | | | | | |

## 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) | LINE COST | | | | | Line No. |
|---|---|---|---|---|---|---|---|---|---|
| Size (h) | Specification (i) | Configuration and Spacing (j) | (k) | Land and Land Rights (l) | Poles, Towers and Fixtures (m) | Conductors and Devices (n) | Asset Retire. Costs (o) | Total (p) | |
| | | | | | | | | | 1 |
| | | | | | | | | | 2 |
| | | | | | | | | | 3 |
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| | | | | | | | | | 44 |

| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

| 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 | Alder, Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 4 | Amity, near Amity, OR | Distrib./unattended | 57.00 | 13.00 | |
| 5 | Arleta, Portland, OR | Distrib./unattended | 57.00 | 13.00 | |
| 6 | Banks, Banks, Or | Distrib./unattended | 57.00 | 13.00 | |
| 7 | Barnes, Salem, OR | Distrib./unattended | 115.00 | 13.00 | |
| 8 | Beaverton, Beaverton, OR | Distrib./unattended | 115.00 | 13.00 | |
| 9 | Bell, near Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 10 | Bethany, Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 11 | Boones Ferry, Lake Oswego, OR | Distrib./unattended | 115.00 | 13.00 | |
| 12 | Boring, near Boring, OR | Distrib./unattended | 57.00 | 13.00 | |
| 13 | Brookwood, near Hillsboro, OR | Distrib./unattended | 57.00 | 13.00 | |
| 14 | Canby, near Barlow, OR | Distrib./unattended | 57.00 | 13.00 | |
| 15 | Canemah, Oregon City, OR | Distrib./unattended | 115.00 | 57.00 | 13.00 |
| 16 | Canyon, Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 17 | Cedar Hills, near Beaverton, OR | Distrib./unattended | 115.00 | 13.00 | |
| 18 | Centennial, near Gresham, OR | Distrib./unattended | 115.00 | 13.00 | |
| 19 | Chemawa BPA, near Salem, OR | Distrib./unattended | 115.00 | | |
| 20 | Chemawa BPA, near Salem, OR | Distrib./unattended | 57.00 | | |
| 21 | Clackamas, Clackamas, OR | Distrib./unattended | 115.00 | 13.00 | |
| 22 | Claxtar, Salem, OR | Distrib./unattended | 57.00 | 13.00 | |
| 23 | Coffee Creek, Sherwood, OR | Distrib./unattended | 115.00 | 13.00 | |
| 24 | Cornelius, Cornelius, OR | Distrib./unattended | 115.00 | 57.00 | 13.00 |
| 25 | Cornelius, Cornelius, OR | Distrib./unattended | 57.00 | 13.00 | |
| 26 | Culver, Salem, OR | Distrib./unattended | 115.00 | 13.00 | |
| 27 | Cornell, Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 28 | Curtis, Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 29 | Dayton, near Dayton, OR | Distrib./unattended | 115.00 | 57.00 | 13.00 |
| 30 | Dayton, near Dayton, OR | Distrib./unattended | 57.00 | 13.00 | |
| 31 | Delaware, Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 32 | Denny, Beaverton, OR | Distrib./unattended | 115.00 | 13.00 | |
| 33 | Dilley, near Forest Grove, OR | Distrib./unattended | 57.00 | 13.00 | |
| 34 | Dunn's Corner, near Sandy, OR | Distrib./unattended | 57.00 | 13.00 | |
| 35 | Durham, Tigard, OR | Distrib./unattended | 115.00 | 13.00 | |
| 36 | E., East Yard, Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 37 | E., East Yard, Portland, OR | Distrib./unattended | 115.00 | 11.00 | |
| 38 | E., West Yard, Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 39 | E., West Yard, Portland, OR | Distrib./unattended | 115.00 | 11.00 | |
| 40 | Eagle Creek, Eagle Creek, OR | Distrib./unattended | 57.00 | 13.00 | |

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

| Line No. | Name and Location of Substation<br>(a) | Character of Substation<br>(b) | VOLTAGE (In MVa)<br>Primary<br>(c) | Secondary<br>(d) | Tertiary<br>(e) |
|---|---|---|---|---|---|
| 1 | Eastport, Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 2 | Elma, near Salem, OR | Distrib./unattended | 57.00 | 13.00 | |
| 3 | Estacada, Estacada, OR | Distrib./unattended | 57.00 | 13.00 | |
| 4 | Fairmount, Salem, OR | Distrib./unattended | 115.00 | 13.00 | |
| 5 | Fairview, Fairview, OR | Distrib./unattended | 115.00 | 13.00 | |
| 6 | Forest Grove BPA, Forest Grove, OR | Distrib./unattended | 115.00 | | |
| 7 | Garden Home, near Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 8 | Glencoe, Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 9 | Glencullen, Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 10 | Glendoveer, near Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 11 | Glisan, Gresham, OR | Distrib./Unattended | 115.00 | 13.00 | |
| 12 | Grand Ronde, Grand Ronde, OR | Distrib./unattended | 115.00 | 57.00 | 13.00 |
| 13 | Grand Ronde, Grand Ronde, OR | Distrib./unattended | 115.00 | 13.00 | |
| 14 | Harborton, near Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 15 | Harmony, near Milwaukie, OR | Distrib./unattended | 115.00 | 13.00 | |
| 16 | Harrison Sub, Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 17 | Hayden Island, near Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 18 | Hemlock, Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 19 | Hillcrest, Salem, OR | Distrib./unattended | 115.00 | 13.00 | |
| 20 | Hillsboro, Hillsboro, OR | Distrib./unattended | 57.00 | 13.00 | |
| 21 | Hogan North, Gresham, OR | Distrib./unattended | 115.00 | 13.00 | |
| 22 | Hogan South, Gresham, OR | Distrib./unattended | 115.00 | 57.00 | 13.00 |
| 23 | Hogan South, Gresham, OR | Distrib./unattended | 115.00 | 13.00 | |
| 24 | Holgate, Portland, OR | Distrib./unattended | 57.00 | 13.00 | |
| 25 | Huber, near Beaverton, OR | Distrib./unattended | 115.00 | 13.00 | |
| 26 | Indian, near Salem, OR | Distrib./unattended | 115.00 | 13.00 | |
| 27 | Island, near Milwaukie, OR | Distrib./unattended | 115.00 | 13.00 | |
| 28 | Jennings Lodge, Jennings Lodge, OR | Distrib./unattended | 115.00 | 13.00 | |
| 29 | Kelley Point, Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 30 | Kelly Butte, Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 31 | King City, near King City, OR | Distrib./unattended | 115.00 | 13.00 | |
| 32 | Leland, Oregon City, OR | Distrib./unattended | 57.00 | 13.00 | |
| 33 | Lents, near Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 34 | Lents, near Portland, OR | Distrib./unattended | 57.00 | 11.00 | |
| 35 | Liberty, Salem, OR | Distrib./unattended | 115.00 | 13.00 | |
| 36 | Main, Hillsboro, OR | Distrib./unattended | 57.00 | 13.00 | |
| 37 | Market Street, Salem, OR | Distrib./unattended | 115.00 | 12.50 | |
| 38 | McClain, Salem, OR | Distrib./unattended | 57.00 | 13.00 | |
| 39 | Meridian, near Tualatin, OR | Distrib./unattended | 115.00 | 13.00 | |
| 40 | Middle Grove, near Middle Grove, OR | Distrib./unattended | 115.00 | 13.00 | |

| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

## SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

| Line No. | Name and Location of Substation (a) | Character of Substation (b) | VOLTAGE (In MVa) Primary (c) | Secondary (d) | Tertiary (e) |
|---|---|---|---|---|---|
| 1 | Midway, near Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 2 | Mill Creek, near Salem, OR | Distrib./unattended | 115.00 | 13.00 | |
| 3 | Mobile sub No. 1, OR | Distrib./unattended | 115.00 | 57.00 | 13.00 |
| 4 | Mobile sub No. 2, OR | Distrib./unattended | 115.00 | 57.00 | 13.00 |
| 5 | Mobile Sub No. 3, OR | Distrib./unattended | 115.00 | 57.00 | 12.50 |
| 6 | Mobile Sub No. 4, OR | Distrib./unattended | 115.00 | 57.00 | 13.00 |
| 7 | Molalla, Molalla, OR | Distrib./unattended | 57.00 | 13.00 | |
| 8 | Mt. Angel, Mt. Angel, OR | Distrib./unattended | 57.00 | 13.00 | |
| 9 | Mt. Pleasant, Oregon City, OR | Distrib./unattended | 115.00 | 13.00 | |
| 10 | Multnomah, Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 11 | Newberg, Newberg, 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 | Orenco, near Hillsboro, OR | Distrib./unattended | 115.00 | 57.00 | 13.00 |
| 18 | Orenco, near Hillsboro, OR | Distrib./unattended | 115.00 | 13.00 | |
| 19 | Orient, near Gresham, OR | Distrib./unattended | 57.00 | 13.00 | |
| 20 | Oswego, Lake Oswego, OR | Distrib./unattended | 115.00 | 13.00 | |
| 21 | Oxford, Salem, OR | Distrib./unattended | 115.00 | 13.00 | |
| 22 | Peninsula Park, Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 23 | Pleasant Valley, near Portland, OR | Distrib./unattended | 115.00 | 12.50 | |
| 24 | Portsmouth, Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 25 | Progress, near Tigard, OR | Distrib./unattended | 115.00 | 13.00 | |
| 26 | Raleigh Hills, near Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 27 | Ramapo, near Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 28 | Redland, near Oregon City, OR | Distrib./unattended | 115.00 | 13.00 | |
| 29 | Reedville, near Beaverton, OR | Distrib./unattended | 115.00 | 13.00 | |
| 30 | Rhododendron Switching, OR | Distrib./unattended | 57.00 | | |
| 31 | Rivergate South Yard, near Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 32 | Rivergate South Yard, near Portland, OR | Distrib./unattended | 115.00 | 11.00 | |
| 33 | Riverview, Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 34 | Rockwood, near Gresham, OR | Distrib./unattended | 115.00 | 13.00 | |
| 35 | Rosemont, near Lake Oswego, OR | Distrib./unattended | 115.00 | 13.00 | |
| 36 | Roseway, Hillsboro, OR | Distrib./unattended | 115.00 | 13.00 | |
| 37 | Ruby,Gresham, OR | Distrib./unattended | 115.00 | 13.00 | |
| 38 | Salem-PGE, near Salem, OR | Distrib./unattended | 57.00 | 13.00 | |
| 39 | Sandy, Sandy, OR | Distrib./unattended | 57.00 | 13.00 | |
| 40 | Scappoose, Scappoose, OR | Distrib./unattended | 115.00 | | |

| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

| Line No. | Name and Location of Substation (a) | Character of Substation (b) | VOLTAGE (In MVa) Primary (c) | Secondary (d) | Tertiary (e) |
|---|---|---|---|---|---|
| 1 | Scholls Ferry, Beaverton, OR | Distrib./unattended | 115.00 | 13.00 | |
| 2 | Scoggin, near Gaston, OR | Distrib./unattended | 57.00 | 13.00 | |
| 3 | Sellwood, Portland, OR | Distrib./unattended | 115.00 | 57.00 | 13.00 |
| 4 | Sellwood, Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 5 | Sheridan, Sheridan, OR | Distrib./unattended | 57.00 | 13.00 | |
| 6 | Shute, Hillsboro, OR | Distrib./unattended | 115.00 | 34.50 | |
| 7 | Silverton, Silverton, OR | Distrib./unattended | 57.00 | 13.00 | |
| 8 | Six Corners, Six Corners, OR | Distrib./unattended | 115.00 | 13.00 | |
| 9 | Springbrook, Newberg, OR | Distrib./unattended | 115.00 | 13.00 | |
| 10 | Springdale, near Springdale, OR | Distrib./unattended | | 12.50 | |
| 11 | St. Helens, near St. Helens, OR | Distrib./unattended | 115.00 | | |
| 12 | St. Johns-BPA, near Portland, OR | Distrib./unattended | | 11.00 | |
| 13 | St. Louis, St. Louis, OR | Distrib./unattended | 57.00 | 13.00 | |
| 14 | St. Marys, East Yard, near Beaverton, OR | Distrib./unattended | 115.00 | 13.00 | |
| 15 | Stephens, Portland, OR | Distrib./unattended | 57.00 | 11.00 | |
| 16 | Sullivan, West Linn, OR | Distrib./unattended | 115.00 | 13.00 | |
| 17 | Summit, Government Camp, OR | Distrib./unattended | 57.00 | 13.00 | |
| 18 | Summit, Government Camp, OR | Distrib./unattended | 24.00 | 13.00 | |
| 19 | Sunset, near Hillsboro, OR | Distrib./unattended | 115.00 | 13.00 | |
| 20 | Sunset, near Hillsboro, OR | Distrib./unattended | 115.00 | 34.50 | |
| 21 | Swan Island, Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 22 | Sylvan, near Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 23 | Tabor, Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 24 | Tabor, Portland, OR | Distrib./unattended | 57.00 | | |
| 25 | Tektronix, Beaverton, OR | Distrib./unattended | 115.00 | 13.00 | |
| 26 | Tigard, Tigard, OR | Distrib./unattended | 115.00 | 12.50 | |
| 27 | Town Center, Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 28 | Tualitin, Tualitin, OR | Distrib./unattended | 115.00 | 13.00 | |
| 29 | Twilight, Canby, OR | Distrib./unattended | 57.00 | 13.00 | |
| 30 | University, Salem, OR | Distrib./unattended | 115.00 | 13.00 | |
| 31 | Urban, Portland, OR | Distrib./unattended | 115.00 | 13.00 | |
| 32 | Waconda, near Hopmere, OR | Distrib./unattended | 57.00 | 12.50 | |
| 33 | Wallace, Salem, OR | Distrib./unattended | 115.00 | 13.00 | |
| 34 | Welches, near Welches, OR | Distrib./unattended | 57.00 | 24.00 | |
| 35 | Welches, near Welches, OR | Distrib./unattended | 57.00 | 13.00 | |
| 36 | West Portland, Lower Yard, near Tigard, OR | Distrib./unattended | 115.00 | | |
| 37 | West Portland, Upper Yard, near Tigard, OR | Distrib./unattended | 115.00 | 13.00 | |
| 38 | West Union, near Hillsboro, OR | Distrib./unattended | 115.00 | 13.00 | |
| 39 | Willamina, near Willamina, OR | Distrib./unattended | 57.00 | 13.00 | |
| 40 | Willbridge, Portland, OR | Distrib./unattended | 115.00 | 11.00 | |

| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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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 | Wilsonville, near Wilsonville, OR | Distrib./unattended | 115.00 | 13.00 | |
| 2 | Woodburn, Woodburn, OR | Distrib./unattended | 57.00 | 13.00 | |
| 3 | Yamhill, near Yamhill, OR | Distrib./unattended | 57.00 | 13.00 | |
| 4 | | | | | |
| 5 | | | | | |
| 6 | | | | | |
| 7 | Bakeoven, BPA, near Bakeoven, OR | Transm./unattended | 500.00 | | |
| 8 | Beaver Plant, near Clatskanie, OR | Transm./unattended | 230.00 | 13.00 | |
| 9 | Beaver Plant, near Clatskanie, OR | Transm./unattended | 230.00 | 24.00 | |
| 10 | Bethel, Salem, OR | Transm./unattended | 230.00 | 115.00 | 13.00 |
| 11 | Bethel, Salem, OR | Transm./unattended | 115.00 | 57.00 | 13.00 |
| 12 | Bethel, Salem, OR | Transm./unattended | 115.00 | 13.00 | |
| 13 | Biglow Canyon Wind Farm, Wasco, OR | Transm./unattended | 230.00 | 34.50 | 13.80 |
| 14 | Blue Lake, Troutdale, OR | Transm./unattended | 230.00 | 115.00 | 13.00 |
| 15 | Blue Lake, Troutdale, OR | Transm./unattended | 115.00 | 13.00 | |
| 16 | Boardman, near Boardman, OR | Transm./unattended | 500.00 | 24.00 | |
| 17 | Boardman, OR | Transm./unattended | 230.00 | 7.20 | |
| 18 | Boardman, OR | Transm./unattended | 24.00 | 7.20 | |
| 19 | Broadview Subst. near Broadview, MT | Transm./unattended | 500.00 | 230.00 | |
| 20 | Buckley, BPA near Buckley, WA | Transm./unattended | 500.00 | | |
| 21 | Captain Jack, BPA, near Malin, OR | Transm./unattended | 500.00 | | |
| 22 | Carver, Carver, OR | Transm./unattended | 230.00 | 115.00 | 13.00 |
| 23 | Carver, Carver, OR | Transm./unattended | 115.00 | 13.00 | |
| 24 | Colstrip Plant, near Colstrip, MT | Transm./unattended | 500.00 | 26.00 | |
| 25 | Colstrip Subst. near Colstrip, MT | Transm./unattended | 500.00 | 230.00 | |
| 26 | Coyote Springs, Boardman, OR | Transm./unattended | 500.00 | | |
| 27 | Faraday, Switchyard, near Estacada, OR | Transm./unattended | 115.00 | 57.00 | 12.50 |
| 28 | Faraday, Switchyard, near Estacada, OR | Transm./unattended | 57.00 | 11.00 | |
| 29 | Faraday Plant, near Estacada, OR | Transm./unattended | 115.00 | 12.50 | |
| 30 | Fort Rock, approx 12 mi NE of Silver Lake, OR | Transm./unattended | 500.00 | | |
| 31 | Grassland, near Boardman, OR | Transm./unattended | 500.00 | | |
| 32 | Gresham, near Gresham, OR | Transm./unattended | 230.00 | 115.00 | 13.00 |
| 33 | Grizzly, BPA, near Madras, OR | Transm./unattended | 500.00 | | |
| 34 | Horizon, Hillsboro, OR | Transm./unattended | 230.00 | 115.00 | 13.00 |
| 35 | Keeler, BPA, Hillsboro, OR | | | | |
| 36 | Linneman, near Gresham, OR | Transm./unattended | 230.00 | 115.00 | 13.00 |
| 37 | Malin, BPA, near Malin, OR | Transm./unattended | 500.00 | | |
| 38 | McLoughlin, near Oregon City, OR | Transm./unattended | 230.00 | 115.00 | 13.00 |
| 39 | Monitor, near Monitor, OR | Transm./unattended | 230.00 | 57.00 | 13.00 |
| 40 | Murrayhill, Beaverton, OR | Transm./unattended | 230.00 | 115.00 | 13.00 |

| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

## 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 | Murrayhill, Beaverton, OR | Transm./unattended | 115.00 | 13.00 | |
| 2 | North Fork, near Estacada, OR | Transm./unattended | 115.00 | 13.00 | |
| 3 | Oak Grove, Three Lynx, OR | Transm./unattended | 115.00 | 13.00 | |
| 4 | Oak Grove, Three Lynx, OR | Transm./unattended | 115.00 | 11.00 | |
| 5 | Oak Grove, Three Lynx, OR | Transm./unattended | 13.00 | 11.00 | |
| 6 | Oak Grove, Three Lynx, OR | Transm./unattended | 13.00 | 0.48 | |
| 7 | Pearl, BPA, near Wilsonville, OR | Transm./unattended | 230.00 | | |
| 8 | Pelton, near Madras, OR | Transm./unattended | 230.00 | 13.00 | |
| 9 | Pelton, near Madras, OR | Transm./unattended | 13.00 | 13.00 | |
| 10 | Port Westward, near Clatskanie, OR | Transm./unattended | 230.00 | 18.00 | 16.50 |
| 11 | River Mill, near Estacada, OR | Transm./unattended | 57.00 | 11.00 | |
| 12 | Rivergate North Yard, near Portland, OR | Transm./unattended | 230.00 | 115.00 | 13.00 |
| 13 | Round Butte, near Madras, OR | Transm./unattended | 500.00 | 230.00 | 12.50 |
| 14 | Round Butte, near Madras, OR | Transm./unattended | 230.00 | 12.50 | |
| 15 | Sand Springs, 22 mi E/22 mi S of Bend, OR | Transm./unattended | 500.00 | | |
| 16 | Sherwood, near Six Corners, OR | Transm./unattended | 230.00 | 115.00 | 13.00 |
| 17 | Slatt, BPA, Arlington, OR | Transm./unattended | 500.00 | | |
| 18 | St. Marys, West Yard, near Beaverton, OR | Transm./unattended | 230.00 | 115.00 | 13.00 |
| 19 | Sullivan, West Linn, OR | Transm./Unattended | 57.00 | 4.15 | |
| 20 | Sycan, 27 mi S of Silver Lake, OR | Transm./unattended | 500.00 | | |
| 21 | Trojan, near Rainier, OR | Transm./unattended | 230.00 | 12.50 | |
| 22 | Troutdale, BPA near Troutdale OR | Transm./unattended | 230.00 | | |
| 23 | Tucannon Mullan Switchyard, Dayton, WA | Transm./unattended | 230.00 | 34.50 | 13.00 |
| 24 | TOTAL MVa | | 30373.00 | 5013.03 | 379.80 |
| 25 | | | | | |
| 26 | | | | | |
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| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa) (f) | Number of Transformers In Service (g) | Number of Spare Transformers (h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|
| 69 | 9 | | Capacitor Banks | 3 | 15,600 | 1 |
| 45 | 2 | | Capacitor Banks | 2 | 12,000 | 2 |
| 56 | 2 | | Capacitor Banks | 4 | 12,000 | 3 |
| 15 | 2 | | | | | 4 |
| 42 | 2 | | Capacitor Banks | 2 | 7,200 | 5 |
| 20 | 1 | | Capacitor Banks | 2 | 3,000 | 6 |
| 42 | 2 | | Capacitor Banks | 2 | 3,600 | 7 |
| 34 | 2 | | Capacitor Banks | 4 | 12,000 | 8 |
| 66 | 3 | | Capacitor Banks | 4 | 12,000 | 9 |
| 56 | 2 | | Capacitor Banks | 5 | 15,000 | 10 |
| 50 | 2 | | Capacitor Banks | 2 | 7,200 | 11 |
| 24 | 2 | | Capacitor Banks | 1 | 12,150 | 12 |
| 28 | 1 | | Capacitor Banks | 2 | 6,000 | 13 |
| 39 | 4 | | Capacitor Banks | 2 | 3,600 | 14 |
| 250 | 6 | | | | | 15 |
| 200 | 4 | | Capacitor Banks | 8 | 28,800 | 16 |
| 56 | 2 | | Capacitor Banks | 4 | 13,200 | 17 |
| 39 | 2 | | Capacitor Banks | 2 | 7,200 | 18 |
| | | | | | | 19 |
| | | | | | | 20 |
| 41 | 2 | | Capacitor Banks | 4 | 13,200 | 21 |
| 28 | 1 | | Capacitor Banks | 2 | 6,000 | 22 |
| 28 | 1 | | Capacitor Banks | 2 | 6,000 | 23 |
| 140 | 1 | | | | | 24 |
| 28 | 1 | | Capacitor Banks | 2 | 6,000 | 25 |
| 28 | 1 | | Capacitor Banks | 2 | 6,000 | 26 |
| 28 | 1 | | Capacitor Banks | 2 | 6,000 | 27 |
| 17 | 1 | | Capacitor Banks | 2 | 6,000 | 28 |
| 125 | 1 | | | | | 29 |
| 22 | 2 | | Capacitor Banks | 4 | 6,000 | 30 |
| 22 | 1 | | | | | 31 |
| 56 | 2 | | Capacitor Banks | 2 | 6,000 | 32 |
| 13 | 1 | | Capacitor Banks | 3 | 9,000 | 33 |
| 14 | 1 | | Capacitor Banks | 2 | 3,000 | 34 |
| 56 | 2 | | Capacitor Banks | 4 | 12,600 | 35 |
| 140 | 2 | | Capacitor Banks | 3 | 21,600 | 36 |
| 63 | 3 | | Capacitor Banks | 1 | 8,400 | 37 |
| 63 | 3 | | Capacitor Banks | 1 | 24,000 | 38 |
| 70 | 1 | | Capacitor Banks | 2 | 31,200 | 39 |
| 14 | 1 | | | | | 40 |

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa) | Number of Transformers In Service | Number of Spare Transformers | CONVERSION APPARATUS AND SPECIAL EQUIPMENT | | | Line No. |
|---|---|---|---|---|---|---|
| | | | Type of Equipment | Number of Units | Total Capacity (In MVa) | |
| (f) | (g) | (h) | (i) | (j) | (k) | |
| 20 | 1 | | | | | 1 |
| 32 | 2 | | Capacitor Banks | 4 | 14,400 | 2 |
| 30 | 2 | | Capacitor Banks | 2 | 3,600 | 3 |
| 25 | 1 | | Capacitor Banks | 1 | 3,600 | 4 |
| 50 | 2 | | Capacitor Banks | 2 | 6,600 | 5 |
| | | | | | | 6 |
| 21 | 1 | | Capacitor Banks | 2 | 6,000 | 7 |
| 22 | 1 | | Capacitor Banks | 2 | 6,000 | 8 |
| 24 | 1 | | Capacitor Banks | 2 | 6,000 | 9 |
| 50 | 2 | | Capacitor Banks | 3 | 9,720 | 10 |
| 45 | 2 | | Capacitor Banks | 4 | 12,000 | 11 |
| 33 | 1 | | | | | 12 |
| 13 | 1 | | Capacitor Banks | 2 | 3,000 | 13 |
| 25 | 1 | | Capacitor Banks | 6 | 19,200 | 14 |
| 50 | 2 | | Capacitor Banks | 4 | 12,000 | 15 |
| 28 | 1 | | Capacitor Banks | 2 | 6,000 | 16 |
| 34 | 2 | | Capacitor Banks | 4 | 12,000 | 17 |
| 28 | 1 | | Capacitor Banks | 2 | 6,000 | 18 |
| 28 | 1 | | Capacitor Banks | 2 | 6,000 | 19 |
| 43 | 2 | | Capacitor Banks | 4 | 14,400 | 20 |
| 56 | 2 | | Capacitor Banks | 4 | 12,600 | 21 |
| 125 | 3 | | | | | 22 |
| 56 | 2 | | Capacitor Banks | 4 | 12,000 | 23 |
| 39 | 2 | | Capacitor Banks | 2 | 7,200 | 24 |
| 56 | 2 | | Capacitor Banks | 2 | 6,000 | 25 |
| 56 | 2 | | Capacitor Banks | 3 | 10,800 | 26 |
| 45 | 2 | | Capacitor Banks | 4 | 12,000 | 27 |
| 53 | 2 | | | | | 28 |
| 56 | 2 | | Capacitor Banks | 4 | 12,000 | 29 |
| 45 | 2 | | Capacitor Banks | 2 | 6,000 | 30 |
| 50 | 2 | | Capacitor Banks | 4 | 14,400 | 31 |
| 28 | 1 | | Capacitor Banks | 2 | 6,000 | 32 |
| 22 | 1 | | | | | 33 |
| 10 | 1 | | | | | 34 |
| 50 | 2 | | Capacitor Banks | 3 | 10,200 | 35 |
| 84 | 3 | | Capacitor Banks | 6 | 20,400 | 36 |
| 28 | 1 | | Capacitor Banks | 2 | 6,000 | 37 |
| 23 | 3 | | | | | 38 |
| 84 | 3 | | Capacitor Banks | 6 | 18,600 | 39 |
| 53 | 2 | | Capacitor Banks | 4 | 12,000 | 40 |

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa) (f) | Number of Transformers In Service (g) | Number of Spare Transformers (h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|
| 34 | 2 | | Capacitor Banks | 1 | 3,600 | 1 |
| 17 | 1 | | Capacitor Banks | 2 | 6,000 | 2 |
| 15 | 1 | | | | | 3 |
| 34 | 1 | | | | | 4 |
| 29 | 1 | | | | | 5 |
| 34 | 1 | | | | | 6 |
| 42 | 2 | | Capacitor Banks | 4 | 9,000 | 7 |
| 20 | 1 | | Capacitor Banks | 3 | 15,000 | 8 |
| 45 | 2 | | Capacitor Banks | | | 9 |
| 39 | 2 | | Capacitor Banks | 3 | 9,600 | 10 |
| 45 | 2 | | Capacitor Banks | 4 | 12,000 | 11 |
| 31 | 3 | | Capacitor Banks | 3 | 15,000 | 12 |
| 20 | 1 | | Capacitor Banks | 4 | 18,000 | 13 |
| 28 | 2 | | | | | 14 |
| 56 | 2 | | Capacitor Banks | 4 | 14,400 | 15 |
| | | | | | | 16 |
| 280 | 2 | | | | | 17 |
| 81 | 3 | | Capacitor Banks | 6 | 18,600 | 18 |
| 15 | 2 | | | | | 19 |
| 34 | 2 | | Capacitor Banks | 2 | 7,200 | 20 |
| 50 | 2 | | Capacitor Banks | 4 | 12,300 | 21 |
| 28 | 1 | | Capacitor Banks | 2 | 6,000 | 22 |
| 56 | 2 | | Capacitor Banks | 4 | 12,000 | 23 |
| 28 | 1 | | | | | 24 |
| 50 | 2 | | Capacitor Banks | 4 | 13,800 | 25 |
| 28 | 1 | | Capacitor Banks | 2 | 6,600 | 26 |
| 28 | 1 | | Capacitor Banks | 2 | 6,000 | 27 |
| 22 | 1 | | | | | 28 |
| 84 | 3 | | Capacitor Banks | 6 | 18,000 | 29 |
| | | | | | | 30 |
| 22 | 1 | | Capacitor Banks | 2 | 7,200 | 31 |
| 22 | 1 | | Capacitor Banks | 2 | 6,716 | 32 |
| 28 | 1 | | Capacitor Banks | 2 | 6,000 | 33 |
| 78 | 3 | | Capacitor Banks | 5 | 15,000 | 34 |
| 28 | 1 | | Capacitor Banks | 2 | 6,000 | 35 |
| 28 | 1 | | Capacitor Banks | 2 | 6,000 | 36 |
| 28 | 1 | | Capacitor Banks | 2 | 6,000 | 37 |
| 45 | 2 | | Capacitor Banks | 4 | 12,000 | 38 |
| 28 | 1 | | Capacitor Banks | 2 | 6,000 | 39 |
| | | | | | | 40 |

| Name of Respondent<br>Portland General Electric Company | This Report Is:<br>(1) [X] An Original<br>(2) [ ] A Resubmission | Date of Report<br>(Mo, Da, Yr)<br>/ / | Year/Period of Report<br>End of 2017/Q4 |
|---|---|---|---|

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa) (f) | Number of Transformers In Service (g) | Number of Spare Transformers (h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|
| 28 | 1 | | Capacitor Banks | 2 | 6,000 | 1 |
| 13 | 2 | | Capacitor Banks | 1 | 10,800 | 2 |
| 140 | 1 | | Capacitor Banks | 1 | 24,000 | 3 |
| 28 | 1 | | Capacitor Banks | 2 | 6,000 | 4 |
| 17 | 1 | | Capacitor Banks | 3 | 19,200 | 5 |
| 100 | 2 | | capacitor Banks | 2 | 9,000 | 6 |
| 33 | 3 | | Capacitor Banks | 2 | 3,600 | 7 |
| 49 | 2 | | Capacitor Banks | 2 | 6,000 | 8 |
| 56 | 2 | | Capacitor Banks | 5 | 36,000 | 9 |
| | | | | | | 10 |
| | | | Capacitor Banks | 1 | 24,000 | 11 |
| | | | | | | 12 |
| 24 | 2 | | Capacitor Banks | 2 | 7,200 | 13 |
| 56 | 2 | | Capacitor Banks | 4 | 12,000 | 14 |
| 100 | 2 | | Capacitor Banks | 2 | 16,800 | 15 |
| 45 | 2 | | Capacitor Banks | 5 | 36,000 | 16 |
| 8 | 1 | 1 | | | | 17 |
| 14 | 1 | | | | | 18 |
| 400 | 8 | | Capacitor Banks | 25 | 150,000 | 19 |
| 250 | 2 | | | | | 20 |
| 53 | 2 | | Capacitor Banks | 4 | 12,000 | 21 |
| 22 | 1 | | Capacitor Banks | 2 | 6,000 | 22 |
| 22 | 1 | | Capacitor Banks | 2 | 6,000 | 23 |
| | | | | | | 24 |
| 84 | 3 | | Capacitor Banks | 6 | 18,000 | 25 |
| 45 | 2 | | Capacitor Banks | 4 | 12,000 | 26 |
| 56 | 2 | | Capacitor Banks | 2 | 6,000 | 27 |
| 56 | 2 | | Capacitor Banks | 4 | 13,200 | 28 |
| 28 | 1 | | Capacitor Banks | 3 | 19,200 | 29 |
| 22 | 1 | | Capacitor Banks | 2 | 7,200 | 30 |
| 112 | 4 | | Capacitor Banks | 6 | 39,600 | 31 |
| 41 | 2 | | Capacitor Banks | 2 | 6,000 | 32 |
| 28 | 1 | | Capacitor Banks | 2 | 6,000 | 33 |
| 10 | 1 | | Capacitor Banks | 1 | 12,000 | 34 |
| 18 | 2 | | Capacitor Banks | 2 | 6,000 | 35 |
| | | | Capacitor Banks | 1 | 24,000 | 36 |
| 56 | 2 | | Capacitor Banks | 4 | 13,200 | 37 |
| 56 | 2 | | Capacitor Banks | 4 | 12,000 | 38 |
| 24 | 2 | | Capacitor Banks | 3 | 7,800 | 39 |
| 20 | 1 | | | | | 40 |

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa) | Number of Transformers In Service | Number of Spare Transformers | CONVERSION APPARATUS AND SPECIAL EQUIPMENT | | | Line No. |
|---|---|---|---|---|---|---|
| | | | Type of Equipment | Number of Units | Total Capacity (In MVa) | |
| (f) | (g) | (h) | (i) | (j) | (k) | |
| 84 | 3 | | Capacitor Banks | 6 | 18,000 | 1 |
| 42 | 2 | | Capacitor Banks | 4 | 13,200 | 2 |
| 15 | 2 | | Capacitor Banks | 1 | 1,800 | 3 |
| | | | | | | 4 |
| | | | | | | 5 |
| | | | | | | 6 |
| | | | | | | 7 |
| 464 | 4 | | | | | 8 |
| 170 | 1 | | | | | 9 |
| 502 | 2 | | | | | 10 |
| 140 | 1 | | | | | 11 |
| 28 | 1 | | Capacitor Banks | 2 | 6,000 | 12 |
| 480 | 3 | | | | | 13 |
| 320 | 1 | | | | | 14 |
| 28 | 1 | | Capacitor Banks | 2 | 6,000 | 15 |
| 685 | 3 | | | | | 16 |
| 55 | 1 | | | | | 17 |
| 55 | 1 | | | | | 18 |
| 80 | 3 | | | | | 19 |
| | | | | | | 20 |
| | | | | | | 21 |
| 640 | 2 | | | | | 22 |
| 56 | 2 | | Capacitor Banks | 4 | 12,000 | 23 |
| 164 | 3 | | | | | 24 |
| 100 | 2 | | | | | 25 |
| 300 | 3 | | | | | 26 |
| 140 | 1 | | | | | 27 |
| 32 | 2 | | | | | 28 |
| 27 | 1 | | | | | 29 |
| | | | Series Capacitor | 1 | 363,000 | 30 |
| | | | | | | 31 |
| 572 | 2 | | | | | 32 |
| | | | | | | 33 |
| 640 | 2 | | | | | 34 |
| | | | | | | 35 |
| 168 | 1 | | | | | 36 |
| | | | Reactors | 3 | 180,000 | 37 |
| 640 | 2 | | | | | 38 |
| 125 | 1 | | | | | 39 |
| 320 | 1 | | | | | 40 |

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

| Capacity of Substation (In Service) (In MVa) (f) | Number of Transformers In Service (g) | Number of Spare Transformers (h) | CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i) | Number of Units (j) | Total Capacity (In MVa) (k) | Line No. |
|---|---|---|---|---|---|---|
| 56 | 2 | | Capacitor Banks | 3 | 10,800 | 1 |
| 53 | 3 | 1 | | | | 2 |
| 8 | 1 | | | | | 3 |
| 64 | 2 | | | | | 4 |
| | | | | | | 5 |
| | | | | | | 6 |
| | | | | | | 7 |
| 164 | 4 | | | | | 8 |
| 3 | 1 | | | | | 9 |
| 450 | 3 | | | | | 10 |
| 32 | 2 | | | | | 11 |
| 520 | 4 | | Capacitor Banks | 1 | 22,000 | 12 |
| 561 | 3 | | Reactors | 12 | 180,000 | 13 |
| 394 | 4 | 2 | | | | 14 |
| | | | Series Capacitor | 1 | 546,000 | 15 |
| 640 | 2 | | | | | 16 |
| | | | | | | 17 |
| 960 | 3 | | Capacitor Banks | 3 | 108,000 | 18 |
| 33 | 1 | | | | | 19 |
| | | | Series Capacitor | 1 | 546,000 | 20 |
| 56 | 2 | | | | | 21 |
| | | | | | | 22 |
| 320 | 2 | | Capacitors/Reactors | 6 | 90,000 | 23 |
| 18827 | 365 | 4 | | 433 | 3,623,886 | 24 |
| | | | | | | 25 |
| | | | | | | 26 |
| | | | | | | 27 |
| | | | | | | 28 |
| | | | | | | 29 |
| | | | | | | 30 |
| | | | | | | 31 |
| | | | | | | 32 |
| | | | | | | 33 |
| | | | | | | 34 |
| | | | | | | 35 |
| | | | | | | 36 |
| | | | | | | 37 |
| | | | | | | 38 |
| | | | | | | 39 |
| | | | | | | 40 |

***Schedule Page: 426 Line No.: 19 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.: 20 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.: 6 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: 426.2 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: 426.2 Line No.: 30 Column: a***

Switching only.

***Schedule Page: 426.2 Line No.: 40 Column: a***

Switching only. Distribution owned by Columbia River PUD.

***Schedule Page: 426.3 Line No.: 10 Column: a***

Regulating only.

***Schedule Page: 426.3 Line No.: 11 Column: a***

Switching only. Distribution owned by Columbia River PUD.

***Schedule Page: 426.3 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: 426.3 Line No.: 24 Column: a***

Switching only.

***Schedule Page: 426.3 Line No.: 36 Column: a***

Switching only.

***Schedule Page: 426.4 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: 426.4 Line No.: 16 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: 426.4 Line No.: 17 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: 426.4 Line No.: 18 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: 426.4 Line No.: 19 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: 426.4 Line No.: 20 Column: a***

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

***Schedule Page: 426.4 Line No.: 21 Column: a***

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

***Schedule Page: 426.4 Line No.: 24 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 is reported.

***Schedule Page: 426.4 Line No.: 25 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: 426.4 Line No.: 26 Column: a**

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

**Schedule Page: 426.4 Line No.: 30 Column: a**

Line compensation only.

**Schedule Page: 426.4 Line No.: 33 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.: 35 Column: a**

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

**Schedule Page: 426.4 Line No.: 37 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.: 7 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.: 8 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.: 9 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.: 14 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.: 15 Column: a**

Line compensation only.

**Schedule Page: 426.5 Line No.: 17 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.: 20 Column: a**

Line compensation only.

**Schedule Page: 426.5 Line No.: 22 Column: a**

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

| Name of Respondent | This Report Is: | Date of Report (Mo, Da, Yr) | Year/Period of Report |
|---|---|---|---|
| Portland General Electric Company | (1) [X] An Original<br>(2) [ ] A Resubmission | / / | End of 2017/Q4 |

## TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

| Line No. | Description of the 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 | 4,973,098 |
| 4 | OPUC Order No. 75-953 | | | |
| 5 | | | | |
| 6 | Catering Services | Salmon Springs Hospitality Group | 921 | 735,465 |
| 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 | 1,399,336 |
| 23 | | | | |
| 24 | | | | |
| 25 | | | | |
| 26 | | | | |
| 27 | | | | |
| 28 | | | | |
| 29 | | | | |
| 30 | | | | |
| 31 | | | | |
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| 34 | | | | |
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| 37 | | | | |
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Schedule | Page No.