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** 2016/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 1,144 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 150 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 Portland General Electric Company	02 Year/Period of Report End of 2016/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 121 SW Salmon Street, Portland, Oregon, 97204	
05 Name of Contact Person Jardon Jaramillo	06 Title of Contact Person Controller & Asst. Treasurer
07 Address of Contact Person *(Street, City, State, Zip Code)* 121 SW Salmon Street, Portland, Oregon, 97204	

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

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name James F. Lobdell	03 Signature James F. Lobdell	04 Date Signed *(Mo, Da, Yr)* 03/28/0017
02 Title SVP of Finance, CFO and Treasurer		

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

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 2016/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".

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	

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 2016/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)
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
	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 (2) [ ] A Resubmission	/ /	End of 2016/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, wholesale purchase, transmission, distribution, and retail sale of electricity in the State of Oregon. The respondent also participates in the wholesale market through the purchase and sale of electricity 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 Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report *(Mo, Da, Yr)* / /	Year/Period of Report End of 2016/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 (2) [ ] A Resubmission	/ /	End of 2016/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.		
13				
14	SunWay 3, LLC	Solar power generation	Dissolved	
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				

Schedule Page: 103 Line No.: 14 Column: c

In January 2016, PGE acquired the assets and liabilities of SunWay 3, LLC, a variable interest entity, at net book value. The entity was subsequently dissolved.

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 2016/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	796,599
2	Senior Vice President of Finance, Chief Financial	James F. Lobdell	417,449
3	Officer and Treasurer		
4	Senior Vice President, Power Supply, Operations,	Maria M. Pope	449,313
5	and Resource Strategy		
6	Senior Vice President, Customer Service	William O. Nicholson	318,917
7	Transmission and Distribution		
8	Vice President, General Counsel and Corporate	J. Jeffery Dudley	369,882
9	Compliance Officer		
10	Vice President, Public Policy and	W. David Robertson	294,140
11	Corporate Resiliency		
12	Vice President, Customer Strategies and Business	Carol A. Dillin	289,722
13	Development		
14	Vice President, Transmission and Distribution	Larry N. Bekkedahl	287,543
15	Vice President, Information Technology and Chief	Campbell A. Henderson	261,749
16	Information Officer		
17	Vice President, Power Supply Generation	Bradley Y. Jenkins	258,654
18	Vice President, Customer Service Operations	Kristin A. Stathis	238,821
19	Vice President, Human Resources, Diversity	Anne Mersereau	230,591
20	and Inclusion		
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33			
34			
35			
36			
37			
38			
39			
40			
41			
42			
43			
44			

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

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

Schedule Page: 104 Line No.: 19 Column: a

Appointed to position effective January 1, 2016

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 2016/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	Sewickley, 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	Avon, Connecticut
26	Retired Chairman of Northeast Utilities	
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46		
47		
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 (2) [ ] A Resubmission	/ /	End of 2016/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
1		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		

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 2016/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
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
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 (2) [ ] A Resubmission	/ /	End of 2016/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
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on 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. Portland General Electric Company (PGE or the Company) has entered into agreements to purchase natural gas transportation capacity to serve the Carty Generating Station (Carty), a 440 MW natural gas-fired baseload resource located adjacent to the Boardman coal-fired generating plant, in eastern Oregon. As authorized in FERC Docket No. CP12-494-000, Gas Transmission Northwest LLC completed a new natural gas pipeline, Carty Lateral, a 24 mile, 20-inch diameter steel pipe, which extends from Ione, Oregon, and terminates at a connection within the Carty facility.

PGE 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. In accordance with Public Utility Commission of Oregon Order No. 15-356, in Docket No. UE-294, the Company will, for ratemaking purposes, include costs under the agreement in its annual power cost update. For accounting purposes, this transportation capacity agreement is treated as a capital lease.

As of December 31, 2016, a capital lease asset of $57 million was reflected within Utility Plant, and accumulated amortization of such asset of $3 million reflected within Accumulated Provision for Depreciation Amortization and Depletion. The present value of the future minimum lease payments due under the agreement included $3 million within Obligations Under Capital Leases-Current and $51 million in Obligations Under Capital Leases-Noncurrent on the Comparative Balance Sheet, respectively. 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 expense of $3 million was capitalized to Construction Work in Progress (Acct 107). Beginning August 1, 2016, amortization of the leased asset of $1 million and interest expense of $2 million has been recorded to Operation Expenses in the Statement of Income through December 31, 2016.

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 $128 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 $21 million to Construction Work in Progress (Acct 107) and a corresponding liability for the same amount to Other Deferred Credits (Acct 253) 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.

5. None

6. Pursuant to PGE's application, the FERC, on February 5, 2016, issued an order in Docket No. ES15-73-000 that authorizes the Company to issue up to $900 million of short-term debt through February 6, 2018. 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, 2016, PGE has a $500 million revolving credit facility scheduled to expire in November 2019. 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 revolving credit facility. PGE classifies any borrowings under the revolving credit facility and outstanding commercial paper as Notes Payable on the Comparative Balance Sheet.

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.

Under the revolving credit facility, as of December 31, 2016, PGE had no borrowings, commercial paper outstanding, or letters of credit issued. As of December 31, 2016, the aggregate available credit capacity under the revolving credit facility was $500 million.

In addition, PGE has four letter of credit facilities that provide a total of $160 million capacity 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 four facilities, $56 million of letters of credit were outstanding, as of December 31, 2016.

During the year ended December 31, 2016, as authorized under the Public Utility Commission of Oregon (OPUC) Order 14-399, the Company issued $140 million of 2.51% Series FMBs due in 2021. In addition, the Company repaid long term-debt as follows, with both the issuance and the repayments occurring in early January:

- Repaid $75 million of 5.80% Series FMBs, due in 2018; and
- Repaid $58 million of 3.81% Series FMBs, due in 2017.

In May 2016, PGE entered into an unsecured credit agreement with certain financial institutions, under which the Company could obtain three separate term loans in an aggregate principal amount of up to $200 million by October 31, 2016. PGE obtained the following three term loans:

- $50 million on May 4, 2016;
- $75 million on June 15, 2016; and
- $25 million on October 31, 2016.

The term loan interest rates are 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, approximately 1.37% as of December 31, 2016, with no other fees.

The credit agreement expires November 30, 2017, at which time any amounts outstanding under the term loans become due and payable. Upon the occurrence of certain events of default, the Company's obligations under the credit agreement may be accelerated. Such events of default include payment defaults to lenders under the credit agreement, covenant defaults, and other customary defaults for financings of this type.

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, 2016, 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:

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.

In January 2003, two class action suits were filed in Marion County Circuit Court (Circuit Court) against PGE. The Dreyer case seeks to represent current PGE customers that were customers during the period from April 1, 1995 to October 1, 2000 (Current Class) and the Morgan case seeks to represent PGE customers that were customers during the period from April 1, 1995 to October 1, 2000, but who are no longer customers (Former Class, together with the Current Class, the Class Action Plaintiffs). The suits seek damages of $190 million plus interest for the Current Class and $70 million plus interest for the Former Class, from the inclusion of a return on investment of the Company's former Trojan nuclear power plant (Trojan) in the rates PGE charged its customers.

In April 2004, the Class Action Plaintiffs filed a Motion for Partial Summary Judgment and in July 2004, PGE also moved for Summary Judgment in its favor on all of the Class Action Plaintiffs' claims. In December 2004, the Judge granted the Class Action Plaintiffs' motion for Class Certification and Partial Summary Judgment and denied PGE's motion for Summary Judgment. In March 2005, PGE filed two Petitions with the Oregon Supreme Court asking the Supreme Court to take jurisdiction and command the trial Judge to dismiss the complaints, or to show cause why they should not be dismissed, and seeking to overturn the Class Certification.

In August 2006, the Oregon Supreme Court issued a ruling on PGE's Petitions abating these class action proceedings until the OPUC responded with respect to the certain issues that had been remanded to the OPUC by the Circuit Court. In October 2006, the Circuit Court issued an Order of Abatement in response to the ruling of the Oregon Supreme Court, abating the class actions.

Following the October 2014 decision of the Oregon Supreme Court upholding the OPUC refund order in the related Trojan regulatory proceeding, the Circuit Court granted PGE's motion to lift the abatement in June 2015. PGE filed a motion for summary judgment dismissing the lawsuits. Following oral argument on PGE's motion for summary judgment, Plaintiffs moved to amend the complaints. PGE opposed the request to amend.

On February 22, 2016, the Marion County Circuit Court denied the plaintiff's motion to amend the Complaint and, on March 16, 2016, 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 general judgment of the Circuit Court in the Court of Appeals for the State of Oregon.

Puget Sound Energy, Inc. v. All Jurisdictional Sellers of Energy and/or Capacity at Wholesale Into Electric Energy and/or Capacity Markets in the Pacific Northwest, Including Parties to the Western System Power Pool Agreement, Federal Energy Regulatory Commission and Ninth Circuit Court of Appeals (collectively, Pacific Northwest Refund proceeding).

In 2001, the FERC called for a hearing to explore whether there may have been unjust and unreasonable charges for spot market sales of electricity in the Pacific Northwest from December 25, 2000 through June 20, 2001 (Pacific Northwest Refund proceeding). During that period, PGE both sold and purchased electricity in the Pacific Northwest. Although FERC's original decision terminated the proceeding and denied the claims for refunds, upon appeal of this decision to the U.S. Ninth Circuit Court of Appeals (Ninth Circuit), the Ninth Circuit remanded the case to the FERC to, among other things, address market manipulation evidence and account for the evidence in any future orders regarding the award or denial of refunds in the proceedings.

In response to the Ninth Circuit remand, the FERC issued several procedural orders that established an evidentiary hearing, defined the scope of the hearing, and described the burden of proof that must be met to justify abrogation of the contracts at issue and the imposition of refunds. The orders held that the *Mobile-Sierra* public interest standard governs challenges to the bilateral contracts at issue in this proceeding, and the strong presumption under *Mobile-Sierra* that the rates charged under each contract are just and reasonable would have to be specifically overcome either by: i) a showing that a respondent had violated a contract or tariff and that the violation had a direct connection to the rate charged under the applicable contract; or ii) a showing that the contract rate at issue imposed an excessive burden or seriously harmed the public interest. The FERC also expanded the scope of the hearing to allow parties to pursue refunds for transactions between January 1, 2000 and December 24, 2000 under Section 309 of the Federal Power Act by showing violations of a filed tariff or rate schedule or of a statutory requirement. The FERC directed the presiding judge, if necessary, to determine a refund methodology and to calculate refunds, but held that a market-wide remedy was not appropriate, given the bilateral contract nature of the Pacific Northwest spot markets. Refund claimants appealed these procedural orders at the Ninth Circuit. On December 17, 2015, the Ninth Circuit held that the FERC reasonably applied the *Mobile-Sierra* presumption to the class of contracts at issue in the proceedings and dismissed evidentiary challenges related to the scope of the proceeding.

Plaintiffs on behalf of the California Energy Resources Scheduling division of the California Department of Water Resources filed a request for rehearing on February 1, 2016. By order issued April 18, 2016, the Ninth Circuit denied plaintiffs' request for panel rehearing of its decision regarding application of the *Mobile-Sierra* presumption.

In response to the evidence and arguments presented during the remand hearing, in May 2015, the FERC issued an order finding that the refund proponents had failed to meet the *Mobile-Sierra* burden with respect to all but one respondent. In December 2015, the FERC denied all requests for rehearing of its order. With respect to the remaining respondent, FERC ordered additional proceedings, and in an order issued October 18, 2016, rejected the California Parties' request for refunds from the respondent, finding that the California Parties had not met their *Mobile-Sierra* burden of proof.

The Company has settled all of the direct claims asserted against it in the proceedings for an immaterial amount. The settlements and associated FERC orders have not fully eliminated the potential for so-called "ripple claims," which have been described by the FERC as "sequential claims against a succession of sellers in a chain of purchases that are triggered if the last wholesale purchaser in the chain is entitled to a refund." Because the remaining respondent previously had stated on the record that it would not pursue ripple claims if it were required to pay refunds pursuant to the additional proceedings described above, the Acting Chief Administrative Law Judge issued an order in February 2016, holding that the issue of ripple claims is terminated for purposes of Phase II of these proceedings. Therefore, unless the current FERC orders are overturned or modified on appeal, the Company does not believe that it will incur any material loss in connection with this matter.

Sierra Club and Montana Environmental Information Center v. PPL Montana LLC, Avista Corporation, Puget Sound Energy, Portland General Electric Company, Northwestern Corporation, and PacifiCorp, U.S. District Court for the District of Montana.

In July 2012, PGE received a Notice of Intent to Sue (Notice) for violations of the CAA at Colstrip Steam Electric Station (CSES) from counsel on behalf of the Sierra Club and the Montana Environmental Information Center (MEIC). The Notice was also addressed to the other CSES co-owners, including Talen Montana, LLC - the operator of CSES. PGE has a 20% ownership interest in Units 3 and 4 of CSES. The Notice alleges certain violations of the CAA, and stated that the Sierra Club and MEIC would: i) request a United States District Court to impose injunctive relief and civil penalties; ii) require a beneficial environmental project in the areas affected by the alleged air pollution; and iii) seek reimbursement of Sierra Club's and MEIC's costs of litigation and attorney's fees.

The Sierra Club and MEIC asserted that the CSES owners violated the Title V air quality operating permit during portions of 2008 and 2009 and that the owners have violated the CAA by failing to timely submit a complete air quality operating permit application to the Montana Department of Environmental Quality. The Sierra Club and MEIC also asserted violations of opacity provisions of the CAA.

In 2013, the Sierra Club and MEIC sued the CSES co-owners, including PGE, for these and additional alleged violations of various environmental related regulations. The plaintiffs sought civil penalties along with relief that included an injunction preventing the co-owners from operating CSES except in accordance with the CAA, the Montana State Implementation Plan, and the plant's federally enforceable air quality permits.

On July 12, 2016, the parties reached a settlement of this case in a consent decree filed in U.S. District Court in Montana. On September 6, 2016, the judge entered the consent decree, representing final approval from the Court. Pursuant to the terms of the settlement, all claims alleging violations against the CSES owners, including PGE, have been dropped, and the owners of Colstrip Power Plant Units 1 and 2 have agreed that on or before July 1, 2022, Units 1 and 2, in which PGE has no ownership interest, shall permanently cease operations and shall not, thereafter, burn any fuel in or otherwise operate its boilers. Colstrip Units 3 and 4 are to remain operational. The Company does not anticipate that the settlement will have a material impact on its ownership interest in Units 3 and 4.

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

In 2013, the Company entered into an agreement (Construction Agreement) with its engineering, procurement and construction contractor - Abeinsa EPC LLC, Abener Construction Services, LLC, Teyma Construction USA, LLC, and Abeinsa Abener Teyma General Partnership, an affiliate of Abengoa S.A. (collectively, the "Contractor") - for the construction of Carty. Liberty Mutual Insurance Company and Zurich American Insurance Company (hereinafter referred to collectively as the "Sureties") provided a performance bond of $145.6 million (Performance Bond) under the Construction Agreement.

On December 18, 2015, the Company declared the Contractor in default under the Construction Agreement and terminated the Construction Agreement. On January 28, 2016, the Company received notice from the International Chamber of Commerce International Court of Arbitration that Abengoa S.A. had submitted a Request for Arbitration in which it alleged that the Company's termination of the Construction Agreement was wrongful and in breach of the agreement terms and does not give rise to any liability of Abengoa S.A. under the terms of a guaranty in favor of PGE pursuant to which Abengoa S.A. agreed to guaranty certain obligations of the Contractor under the Construction Agreement. PGE disagrees with the assertions in the Request for Arbitration and on February 29, 2016 filed a Complaint and Motion for Preliminary Injunction in the U.S. District Court for the District of Oregon seeking to have the arbitration claim dismissed on the grounds that the Company has not made a demand under the Abengoa S.A. guaranty, and therefore the matter is not ripe for arbitration.

On March 28, 2016, Abengoa S.A. and several of its foreign affiliates filed petitions for recognition under Chapter 15 of the U.S. Bankruptcy Code requesting interim relief, including an injunction precluding the prosecution of any proceedings against the Chapter 15 debtors. On March 29, 2016, a number of Abengoa S.A.'s U.S. subsidiaries, including the four entities that collectively comprise the Contractor, filed voluntary petitions for relief under Chapter 11 of the U.S. Bankruptcy Code. As a result, on April 5, 2016, the U.S. District Court issued an order stating that the Company's District Court action against Abengoa S.A. was stayed. In June 2016, the Company filed with the bankruptcy court in the Chapter 11 proceeding a motion for relief from stay with respect to the four entities that collectively comprise the Contractor, which allows the Company to bring claims against such entities in the U.S. District Court. On October 21, 2016, PGE filed a complaint in the U.S. District Court for the District of Oregon against Abeinsa for failure to satisfy its obligations under the Construction Agreement. For further information regarding this complaint, see "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," below.

On March 9, 2016, the Sureties delivered a letter to the Company denying liability in whole under the Performance Bond. In the letter, the Sureties make the following assertions in support of their determination:

1. that, because the Contractor and its parent company, Abengoa S.A., have alleged that PGE wrongfully terminated the Construction Agreement and have requested arbitration of the claim, PGE must disprove such claim as a condition precedent to recovery under the Performance Bond; and

2. that, irrespective of the outcome of the foregoing wrongful termination claim, the Sureties have various contractual and equitable defenses to payment and are not liable to PGE for any amount under the Performance Bond.

The Company disagrees with the foregoing assertions and on March 23, 2016 filed a breach of contract action against the Sureties in the U.S. District Court for the District of Oregon. 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.

On April 15, 2016, the Sureties filed a motion to stay the proceeding, alleging that PGE's claims should be addressed in the arbitration proceeding initiated by Abengoa S.A. in January, 2016, and referenced above, because PGE's claims are intertwined with the issues involved in such arbitration and all parties necessary to resolve PGE's claims are parties to the arbitration. PGE opposed the motion and filed a motion to enjoin the Sureties from pursuing, in the ICC arbitration proceeding, claims relating to the Performance Bond.

On July 27, 2016, the judge denied the Sureties' motion to stay the case in favor of a pending ICC Arbitration and granted PGE's motion for an injunction prohibiting the Sureties from pursuing any Performance Bond claims in the ICC Arbitration. The Sureties appealed the rulings to the Ninth Circuit Court of Appeals. On December 13, 2016, the Ninth Circuit issued an Order staying the district court proceeding pending a decision on the Sureties' appeal. Oral argument on the Sureties' appeal is scheduled for May 2017.

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.

On October 21, 2016, PGE filed a complaint in the U.S. District Court of the District of Oregon against Abeinsa for failure to satisfy its obligations under the Construction Agreement. PGE is seeking damages from Abeinsa 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.

10. None

11. (Reserved)

12. None

13. Changes in Officers:

    On January 1, 2016, Anne F. Mersereau, duly appointed, assumed the position of Vice President, Human Resources, Diversity and Inclusion.

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 (2) [ ] A Resubmission	/ /	End of 2016/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	9,701,607,393	8,722,574,599
3	Construction Work in Progress (107)	200-201	212,574,352	545,045,342
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		9,914,181,745	9,267,619,941
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	4,367,096,860	4,094,637,726
6	Net Utility Plant (Enter Total of line 4 less 5)		5,547,084,885	5,172,982,215
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)		5,547,084,885	5,172,982,215
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		45,528,825	40,534,473
19	(Less) Accum. Prov. for Depr. and Amort. (122)		15,872,239	14,460,460
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	225,325	2,579,954
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)		4,155	0
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		79,029,625	77,053,592
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		4,932,477	62,569
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		113,848,168	105,770,128
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		4,705,005	3,504,212
36	Special Deposits (132-134)		7,742,604	33,201,844
37	Working Fund (135)		22,200	22,200
38	Temporary Cash Investments (136)		1,000,000	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		130,689,416	129,569,243
41	Other Accounts Receivable (143)		30,676,525	34,045,749
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		6,391,021	6,141,525
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		11,631	10,741
45	Fuel Stock (151)	227	29,885,835	37,743,684
46	Fuel Stock Expenses Undistributed (152)	227	2,656,990	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	43,215,761	39,858,519
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	1,967,963	1,162,155

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	4,320,139	4,074,812
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)		52,868,533	45,186,373
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)		107,297,016	94,792,424
62	Miscellaneous Current and Accrued Assets (174)		-2,481	88,407
63	Derivative Instrument Assets (175)		23,330,838	10,380,301
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		4,932,477	62,569
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)		429,064,477	427,436,570
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		11,078,032	11,429,778
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	520,947	65,583
72	Other Regulatory Assets (182.3)	232	513,975,906	639,518,308
73	Prelim. Survey and Investigation Charges (Electric) (183)		2,586,289	444,923
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)		-47,341	156,964
77	Temporary Facilities (185)		0	13,785
78	Miscellaneous Deferred Debits (186)	233	14,037,620	12,588,452
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)		22,306,993	16,341,107
82	Accumulated Deferred Income Taxes (190)	234	357,636,563	369,627,897
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		922,095,009	1,050,186,797
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		7,012,092,539	6,756,375,710

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 2016/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	1,205,506,206	1,199,786,255
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	18,838,745
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	23,073,915
11	Retained Earnings (215, 215.1, 216)	118-119	1,150,098,955	1,070,047,158
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	214,325	153,969
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)	-7,664,109	-7,923,203
16	Total Proprietary Capital (lines 2 through 15)		2,343,880,682	2,257,829,009
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	2,211,400,000	2,204,400,000
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	150,077,857	83,849
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		598,395	655,815
24	Total Long-Term Debt (lines 18 through 23)		2,360,879,462	2,203,828,034
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		51,220,862	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		8,883,992	10,370,510
29	Accumulated Provision for Pensions and Benefits (228.3)		393,771,443	371,521,184
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		670,584	10,309,396
32	Long-Term Portion of Derivative Instrument Liabilities		125,236,136	160,800,699
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		161,101,224	150,704,725
35	Total Other Noncurrent Liabilities (lines 26 through 34)		740,884,241	703,706,514
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	5,999,500
38	Accounts Payable (232)		227,364,147	202,835,442
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		337,639	368,204
41	Customer Deposits (235)		16,176,504	15,183,863
42	Taxes Accrued (236)	262-263	12,632,394	12,645,325
43	Interest Accrued (237)		24,925,797	24,643,802
44	Dividends Declared (238)		29,600,824	27,679,814
45	Matured Long-Term Debt (239)		0	0

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		12,222,118	12,455,197
48	Miscellaneous Current and Accrued Liabilities (242)		32,580,354	39,159,727
49	Obligations Under Capital Leases-Current (243)		2,661,556	0
50	Derivative Instrument Liabilities (244)		169,624,416	290,388,592
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		125,236,136	160,800,699
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)		402,889,613	470,558,767
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	38,706,904	11,447,372
60	Other Regulatory Liabilities (254)	278	98,334,688	106,949,335
61	Unamortized Gain on Reaquired Debt (257)		50,325	58,377
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		790,256,094	722,917,080
64	Accum. Deferred Income Taxes-Other (283)		236,210,530	279,081,222
65	Total Deferred Credits (lines 56 through 64)		1,163,558,541	1,120,453,386
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		7,012,092,539	6,756,375,710

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 2016/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	1,939,166,814	1,914,921,070		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,020,207,505	1,043,679,349		
5	Maintenance Expenses (402)	320-323	144,242,966	138,565,097		
6	Depreciation Expense (403)	336-337	266,415,570	252,397,595		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	7,087,268	5,026,773		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	44,097,840	38,364,891		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		-12,840,314	-13,299,647		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		13,760,743	33,462,767		
13	(Less) Regulatory Credits (407.4)		2,761,244	15,271,409		
14	Taxes Other Than Income Taxes (408.1)	262-263	117,893,057	114,643,947		
15	Income Taxes - Federal (409.1)	262-263	11,475,291	4,811,998		
16	- Other (409.1)	262-263	3,247,837	809,455		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	240,078,412	257,577,936		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	202,432,150	216,856,401		
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	35,337		
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		3,259,304	2,952,034		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,653,696,747	1,646,899,722		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		285,470,067	268,021,348		

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
1,939,166,814	1,914,921,070					2
						3
1,020,207,505	1,043,679,349					4
144,242,966	138,565,097					5
266,415,570	252,397,595					6
7,087,268	5,026,773					7
44,097,840	38,364,891					8
						9
-12,840,314	-13,299,647					10
						11
13,760,743	33,462,767					12
2,761,244	15,271,409					13
117,893,057	114,643,947					14
11,475,291	4,811,998					15
3,247,837	809,455					16
240,078,412	257,577,936					17
202,432,150	216,856,401					18
						19
						20
-35,338	35,337					21
						22
						23
3,259,304	2,952,034					24
1,653,696,747	1,646,899,722					25
285,470,067	268,021,348					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 (2) [ ] A Resubmission	/ /	End of 2016/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)		285,470,067	268,021,348		
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)		2,827,339	3,464,148		
34	(Less) Expenses of Nonutility Operations (417.1)		2,690,302	3,640,827		
35	Nonoperating Rental Income (418)		2,576,880	2,591,798		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	59,882	239,353		
37	Interest and Dividend Income (419)		214,373	571,809		
38	Allowance for Other Funds Used During Construction (419.1)		20,604,316	21,253,692		
39	Miscellaneous Nonoperating Income (421)		-327,195	-749,842		
40	Gain on Disposition of Property (421.1)					
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		23,265,293	23,730,131		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		1,886,981	1,688,692		
46	Life Insurance (426.2)		-566,291	77,598		
47	Penalties (426.3)		295	360,566		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,036,435	866,200		
49	Other Deductions (426.5)		2,763,277	3,286,482		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		5,120,697	6,279,538		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	1,395,973	1,315,094		
53	Income Taxes-Federal (409.2)	262-263	-683,007	-1,035,472		
54	Income Taxes-Other (409.2)	262-263	-160,732	-248,431		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	268,228	179,279		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	1,483,114	748,148		
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)		-662,652	-537,678		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		18,807,248	17,988,271		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		114,599,147	118,606,342		
63	Amort. of Debt Disc. and Expense (428)		1,028,897	1,022,130		
64	Amortization of Loss on Reaquired Debt (428.1)		2,570,544	1,518,585		
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)		4,168,461	5,242,336		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		10,819,605	12,519,680		
70	Net Interest Charges (Total of lines 62 thru 69)		111,539,392	113,861,661		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		192,737,923	172,147,958		
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)		192,737,923	172,147,958		

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 2016/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		1,066,194,363	996,253,663
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)		192,678,041	171,908,605
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			-112,625,770	(102,237,265)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-112,625,770	(102,237,265)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		-474	269,360
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,146,246,160	1,066,194,363
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		3,852,795	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)		1,150,098,955	1,070,047,158
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		153,969	183,976
50	Equity in Earnings for Year (Credit) (Account 418.1)		59,882	239,353
51	(Less) Dividends Received (Debit)			270,000
52	Transfer In Due to Dissolution of Subsidiary		474	640
53	Balance-End of Year (Total lines 49 thru 52)		214,325	153,969

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	192,737,923	172,147,958
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	317,600,678	295,789,259
5	Amortization of Debt Discount	3,591,389	2,548,767
6	Amortization of Unrecovered Plant	-12,840,314	-13,299,647
7	Price Risk Management	-133,714,713	59,311,710
8	Deferred Income Taxes (Net)	36,431,376	40,152,666
9	Investment Tax Credit Adjustment (Net)		
10	Net (Increase) Decrease in Receivables	-10,006,935	-10,222,879
11	Net (Increase) Decrease in Inventory	792,482	-526,612
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	14,356,015	5,986,805
14	Net (Increase) Decrease in Other Regulatory Assets	147,641,220	-1,848,803
15	Net Increase (Decrease) in Other Regulatory Liabilities	-24,453,292	-11,003,687
16	(Less) Allowance for Other Funds Used During Construction	20,604,316	21,253,692
17	(Less) Undistributed Earnings from Subsidiary Companies	59,882	239,353
18	Margin Deposit	26,451,881	-21,629,460
19	Other	10,867,591	19,122,858
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	548,791,103	515,035,890
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-603,153,901	-591,283,708
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-4,994,352	-7,833,099
30	(Less) Allowance for Other Funds Used During Construction	-20,604,316	-21,253,692
31	Other Capital Activities	1,411,779	-17,495,919
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-586,132,158	-595,359,034
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	1,306,021
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	23,321,299
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 (2) [ ] A Resubmission	/ /	End of 2016/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) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48	Other Investments	-2,574,742	-2,574,918
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	-24,723,652	-19,141,609
54	Sales of Trojan Decommissioning Secruities	26,681,261	21,726,468
55	Distribution from Nuclear Decommissioning Trust		50,000,000
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-584,243,892	-520,721,773
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	290,000,000	145,000,000
62	Preferred Stock		
63	Common Stock	-2,546,583	271,470,729
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		5,999,500
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	287,453,417	422,470,229
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-133,005,992	-442,005,989
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Debt Issue Costs	-601,849	-629,975
78	Net Decrease in Short-Term Debt (c)	-5,999,500	
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-110,192,494	-97,074,376
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	37,653,582	-117,240,111
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	2,200,793	-122,925,994
87			
88	Cash and Cash Equivalents at Beginning of Period	3,526,412	126,452,406
89			
90	Cash and Cash Equivalents at End of period	5,727,205	3,526,412

FOOTNOTE DATA

Schedule Page: 120 Line No.: 6 Column: b

Includes $16.7 million of amortization of Trojan spent fuel settlement as amounts are refunded to customers.

Schedule Page: 120 Line No.: 6 Column: c

Includes $16.7 million of amortization of Trojan spent fuel settlement as amounts are refunded to customers.

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)	$ 3,504,212	$ 4,705,005
Working Funds (135)	22,200	22,200
Temporary Cash Investments (136)	—	1,000,000
	$ 3,526,412	$ 5,727,205

	2015	2016
Cash paid during the year:		
Interest	$ 120,372,682	$ 114,362,752
Allowance for borrowed funds used during construction	(12,519,680)	(10,819,605)
	$ 107,853,002	$ 103,543,147
Income Taxes	$ 2,655,700	$ 15,502,009
Non-cash investing and financing activities:		
Accrued capital additions	$ 31,912,785	$ 49,990,942
Accrued dividends payable	27,679,814	29,600,824
Assets obtained under leasing arrangements	—	77,991,864
Preliminary engineering transferred to Construction work in progress	89,854	348,144

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, 2016, PGE served approximately 863,000 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, 2016, PGE had 2,752 employees, with 783 employees covered under one of two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 730 and 53 employees and expire March 2020 and August 2017, 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, 2016 up to February 17, 2017, the date that the Company's U.S. GAAP financial statements were issued, and has updated such evaluation for disclosure purposes through March 28, 2017. 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, of which PGE had $1 million as of December 31, 2016 and none as of December 31, 2015.

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 2016 or 2015.

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, oil, 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, PGE recognizes a realized gain or loss on the derivative instrument.

Electricity and natural gas sale and purchase transactions that are physically settled 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 $8 million and $33 million as of December 31, 2016 and 2015, respectively. Letters of credit provided as collateral are not recorded on the Company's Comparative Balance Sheet and were $17 million and $63 million as of December 31, 2016 and 2015, 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 for use in its generating plants. Fuel inventories include natural gas, coal, and oil. Periodically, the Company assesses the realizability of inventory for purposes of determining that inventory is recorded at the lower of average cost or market.

Utility Plant

Capitalization Policy

Utility Plant is capitalized at its 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 the Company'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 a FERC license 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, the Company 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 2016 and 2015. AFDC from borrowed funds was $11 million in 2016 and $13 million in 2015 and is reflected as a reduction to Interest expense. AFDC from equity funds, included in Other Income, was $21 million in 2016 and 2015.

On July 29, 2016, PGE placed Carty into service, a baseload natural gas-fired generating plant in Eastern Oregon, located adjacent to the Boardman coal-fired generating plant (Boardman). As of December 31, 2016, PGE had $634 million included in Utility Plant for Carty. On November 3, 2015, the OPUC issued an order approving settlements reached in PGE's 2016 GRC filing, including capital costs of up to $514 million, including AFDC, for Carty and that Carty would be included in customer prices when the plant was placed in service, provided that occurred by July 31, 2016. As Carty was placed in service on July 29, 2016, the Company was authorized to include in customer prices, effective August 1, 2016, the revenue requirement necessary to allow for recovery of capital costs of up to $514 million, as well as Carty's operating costs. See Note 16, Contingencies, for further information regarding Carty.

Depreciation and Amortization

Depreciation is computed using the straight-line method, based upon original cost, and includes an estimate for cost of removal and expected salvage. Depreciation Expense as a percent of the related average depreciable plant in service was 3.5% in 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 2013, with an order received from the OPUC in September 2014 authorizing new depreciation rates effective January 1, 2015. In December 2016, a depreciation study was completed, which was incorporated into the Company's 2018 general rate case filed with the OPUC at the end of February 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 the Company'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 $257 million and $227 million as of December 31, 2016 and 2015, respectively, with amortization expense of $44 million in 2016 and $38 million in 2015. Future estimated amortization expense as of December 31, 2016 is as follows: $45 million in 2017; $44 million in 2018; $38 million in 2019; $34 million in 2020; and $22 million in 2021.

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 the Company'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. PGE 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 the Company'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 each year's forecasted net variable power costs (NVPC) included in customer prices (baseline NVPC) and actual NVPC. PGE is subject to a portion of the business risk or benefit associated with the difference between actual NVPC and baseline NVPC by application of an asymmetrical "deadband," which ranges from $15 million below to $30 million above baseline NVPC. NVPC consists of i) 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 ii) wholesale sales, which are classified as Operating Revenues in the Statement of Income.

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 that 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 2016, 9.68% for 2015, and 9.75% for 2014.

Any estimated refund to customers pursuant to the PCAM is recorded as a reduction in Revenues in the Company'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 a market-risk premium are not available. The present value of estimated future dismantlement and restoration costs is capitalized and included in Utility Plant, net 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 and amortization in the Statement of Income. Changes in the ARO resulting from the passage of time (accretion) is based on the original discount rate and recognized as an increase in the carrying amount of the liability and as a charge to accretion expense, which is classified as 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 the AROs' 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 $49 million as of December 31, 2016 and $45 million as of December 31, 2015. 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 reasonably estimated, disclosure of the loss contingency includes a statement to that effect 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. The prices charged to customers are subject to federal (FERC) or state (OPUC) regulation. 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 2016 and 2015, and $42 million in 2014.

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 deferred tax assets and liabilities that are related to certain property 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 assets of $89 million as of December 31, 2016 and 2015 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 Net Interest Charges and Penalties, 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 is evaluating which transition method it will elect. The Company does not anticipate any material changes to its revenue policy for tariff-based revenues, which comprises a majority of PGE's retail revenues, as performance obligations are expected to be satisfied in a similar recognition pattern. PGE continues to evaluate the impacts the new guidance may have on its financial position, results of operations, and cash flows, particularly related to recognizing revenue for certain contracts where collectibility may be in question, the extent to which certain transactions such as contributions in aid of construction are within the scope of the standard, certain matters of presentation of alternative revenue programs (such as decoupling), wholesale, and other operating revenue contracts.

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 and must be applied on a modified retrospective basis as of the beginning of the earliest comparative period presented. The new standard also provides reporting entities the option to elect a package of practical expedients for existing leases that commenced before the effective date. Early adoption is permitted. The Company is in the process of evaluating the impact to its financial position, results of operations, and cash flows of the adoption of ASU 2016-02.

In August 2016, the FASB issued ASU 2016-15, *Statement of Cash Flows (Topic 230), Classification of Certain Cash Receipts and Cash Payments* (ASU 2016-15), with the intention to reduce diversity in practice, as well as simplify elements of classification within the Statement of Cash Flows for certain transactions. The new ASU prescribes specific clarification guidance for the following eight classes of transactions: debt prepayment or debt extinguishment costs, settlement of zero-coupon debt instruments, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims, proceeds from the settlement of corporate-owned life insurance policies, distributions received from equity method investments, beneficial interest in securitization transactions, and separately identifiable cash flows and application of the predominance principal. For calendar year-end public entities, the update will be effective for annual periods beginning January 1, 2018 and requires application using a retrospective transition method. Early adoption is permitted. The Company is in the process of evaluating the impacts of adoption of ASU 2016-15 to the presentation of cash flows.

Recently Adopted Accounting Standard

In August 2015, the FASB issued ASU 2015-15, *Interest-Imputation of Interest (Subtopic 835-30): Presentation of Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements-Amendments to SEC Paragraphs Pursuant to Staff Announcement at June 18, 2015 EITF Meeting (SEC Update)* (ASU 2015-15), which clarifies that the SEC staff would "not object to an entity deferring and presenting debt issuance costs as an asset and subsequently amortizing the deferred debt issuance costs ratably over the term of the line-of-credit arrangement" given the lack of guidance on this topic in ASU 2015-03. Therefore, as allowed under this update, the Company records debt issuance costs associated with its line-of-credit arrangements as an asset within Miscellaneous Deferred Debits, and amortizes the costs over the term of the agreement.

In May 2015, the FASB issued ASU 2015-07, *Fair Value Measurement (Topic 820), Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)* (ASU 2015-07), which removes the requirement to categorize within the fair value hierarchy investments for which fair value is measured using the net asset value per share as a practical expedient. The amendments also remove the requirement to make certain disclosures for all investments that are eligible to be measured at fair value using the net asset value per share as a practical expedient. Instead, such disclosures are restricted only to investments that the entity has decided to measure using the practical expedient. The Company has retrospectively adopted the provisions of this update as of January 1, 2016, which was the original effective date for calendar year-end, public entities. As a result, certain investments have been retrospectively reclassified within the Company's fair value disclosures of its Nuclear decommissioning trust and Non-qualified benefit plan trust. See Note 4, Fair Value of Financial Instruments for more information. Also, certain benefit plan assets have been reclassified by the Company as seen in Note 10, Employee Benefits. The adoption of this guidance had no impact on the Company's financial position, results of operations, or cash flows.

In March 2016, the FASB issued ASU 2016-09, *Compensation-Stock Compensation (Topic 718), Improvements to Employee Share-Based Payment Accounting* (ASU 2016-09), which is designed to simplify the presentation and accounting for certain income tax effects, employer tax withholding requirements, forfeiture assumptions, and Statement of Cash Flows presentation related to share-based payment awards. PGE has early adopted the provisions of this ASU effective January 1, 2016, which had an immaterial impact on the Company's financial position, results of operations, or cash flows.

NOTE 3: COMPARATIVE BALANCE SHEET COMPONENTS

Accumulated Provision for Uncollectible Accounts

The following is the activity in the Accumulated Provision for Uncollectible Accounts (in millions):

	Years Ended December 31,	
	2016	2015
Balance as of beginning of year	$ 6	$ 6
Increase in provision	5	6
Amounts written off, less recoveries	(5)	(6)
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	
	2016	2015	2016	2015
Cash equivalents	$ 21	$ 18	$ 1	$ 1
Marketable securities, at fair value:				
Equity securities	—	—	6	5
Debt securities	20	22	1	1
Insurance contracts, at cash surrender value	—	—	26	26
	$ 41	$ 40	$ 34	$ 33

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, 2016 and 2015, 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. Pursuant to the adoption of ASU 2015-07, *Fair Value Measurement (Topic 820), Disclosures for Investments in Certain Entities that Calculate Net Asset Value per share (or Its Equivalent)*, as disclosed in Note 2, Summary of Significant Accounting Policies, 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, and prior period amounts have been retrospectively reclassified to conform to current presentation.

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, 2016 and 2015, 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, 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)					
Money market funds	—	—	—	—	—
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.

	As of December 31, 2015				
	Level 1	Level 2	Level 3	Other(2)	Total
Assets:					
Nuclear decommissioning trust: (1)					
Debt securities:					
Domestic government	$ 6	$ 8	$ —	$ —	$ 14
Corporate credit	—	8	—	—	8
Money market funds measured at NAV(2)	—	—	—	18	18
Non-qualified benefit plan trust: (3)					
Money market funds	—	—	—	—	—
Equity securities—domestic	3	—	—	—	3
Debt securities—domestic government	1	—	—	—	1
Investments measured at NAV:(2)					
Money market funds	—	—	—	1	1
Collective trust—domestic equity	—	—	—	2	2
Assets from price risk management activities: (1) (4)					
Electricity	—	7	—	—	7
Natural gas	—	3	—	—	3
	$ 10	$ 26	$ —	$ 21	$ 57
Liabilities - Liabilities from price risk management activities: (1) (4)					
Electricity	$ —	$ 28	$ 105	$ —	$ 133
Natural gas	—	144	14	—	158
	$ —	$ 172	$ 119	$ —	$ 291

(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, and have been retrospectively reclassified pursuant to the implementation of ASU 2015-07. For further information see Note 2, Summary of Significant Accounting Policies.
(3) Excludes insurance policies of $26 million, which are recorded at cash surrender value.
(4) For further information, see Note 5, Price Risk Management.

Trust assets held in the Nuclear decommissioning and Non-qualified benefit plan 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.

For 2015 and most of 2016 money market funds in the NQ Plan were valued at NAV as a practical expedient and not included in the fair value hierarchy. As of December 31, 2016 the NQ Plan transitioned to exchange traded government money market funds and are 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 Plan continues to be 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. A majority of the funds provide for daily liquidity with appropriate written notice. One fund allows for withdrawal from all accounts as of the last day on each calendar month, with at least ten days prior written notice, and provides for a 95% payment to be made within 30 days, and the balance paid after the annual fund audit is complete. Common and collective trusts are not classified in the fair value hierarchy as they are valued at NAV as a practical expedient.

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, 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					
As of December 31, 2015:							
Electricity physical forward	$ —	$ 105	Discounted cash flow	Electricity forward price (per MWh)	$ 8.50	$ 84.47	$ 30.69
Natural gas financial swaps	—	14	Discounted cash flow	Natural gas forward price (per Dth)	2.06	3.70	2.54
Electricity financial futures	—	—	Discounted cash flow	Electricity forward price (per MWh)	9.98	27.36	19.26
	$ —	$ 119					

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	
	2016	2015
Net liabilities from price risk management activities as of beginning of year	$ 119	$ 100
Net realized and unrealized losses *	11	80
Net transfers in to Level 3 from Level 2	(1)	—
Net transfers out of Level 3 to Level 2	(10)	(61)
Net liabilities from price risk management activities as of end of year	$ 119	$ 119
Level 3 net unrealized losses that have been fully offset by the effect of regulatory accounting	$ 11	$ 80

* Includes nominal net realized losses in 2016 and 2015, respectively.

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, 2016, there were $1 million of transfers into Level 3 from Level 2, as reflected in the table above. During 2015, there were no significant amounts 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, 2016, the carrying amount of PGE's long-term debt was $2,361 million and its estimated aggregate fair value was $2,693 million, consisting of $2,543 million and $150 million classified as Level 2 and Level 3, respectively, in the fair value hierarchy. As of December 31, 2015, the carrying amount of PGE's long-term debt was $2,204 and its estimated aggregate fair value was $2,455 million, classified as Level 2 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,	
	2016	2015
Current assets:		
Commodity contracts:		
Electricity	$ 6	$ 7
Natural gas	12	3
Total current derivative assets	18	10
Noncurrent assets:		
Commodity contracts:		
Electricity	1	—
Natural gas	4	—
Total noncurrent derivative assets	5	—
Total derivative assets not designated as hedging instruments	$ 23	$ 10
Total derivative assets	$ 23	$ 10
Current liabilities:		
Commodity contracts:		
Electricity	$ 12	$ 36
Natural gas	32	94
Total current derivative liabilities	44	130
Noncurrent liabilities:		
Commodity contracts:		
Electricity	106	97
Natural gas	19	64
Total noncurrent derivative liabilities	125	161
Total derivative liabilities not designated as hedging instruments	$ 169	$ 291
Total derivative liabilities	$ 169	$ 291

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,	
	2016	2015
Commodity contracts:		
Electricity	8 MWh	12 MWh
Natural gas	107 Dth	124 Dth
Foreign currency exchange	$ 22 Canadian	$ 7 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, 2016 and 2015, gross amounts included as Derivative Instrument Liabilities subject to master netting agreements were $115 million and $111 million, respectively, for which PGE posted collateral of $11 million and $14 million, which consisted entirely of letters of credit. As of December 31, 2016, of the gross amounts included, $112 million was for electricity and $3 million was for natural gas compared to $104 million for electricity and $7 million for natural gas recognized as of December 31, 2015.

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,	
	2016	**2015**
Commodity contracts:		
Electricity	$ 34	$ 72
Natural Gas	(56)	103
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 (gains) of $13 million and net losses of $160 million for the years ended December 31, 2016 and 2015, 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, 2016 related to PGE's derivative activities would be realized as a result of the settlement of the underlying derivative instrument (in millions):

	2017	**2018**	**2019**	**2020**	**2021**	**Thereafter**	**Total**
Commodity contracts:							
Electricity	$ 6	$ 7	$ 7	$ 7	$ 7	$ 77	$ 111
Natural gas	20	7	6	2	—	—	35
Net unrealized loss	$ 26	$ 14	$ 13	$ 9	$ 7	$ 77	$ 146

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, 2016 was $164 million, for which the Company had posted $14 million in collateral, consisting entirely of letters of credit. If the credit-risk-related contingent features underlying these agreements were triggered at December 31, 2016, the cash requirement to either post as collateral or settle the instruments immediately would have been $149 million. As of December 31, 2016, PGE had posted a nominal amount of 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,	
	2016	2015
Assets from price risk management activities:		
Counterparty A	22 %	5 %
Counterparty B	17	8
Counterparty C	12	8
Counterparty D	8	10
Counterparty E	1	59
	60 %	90 %
Liabilities from price risk management activities:		
Counterparty F	66 %	36 %
Counterparty C	7	10
Counterparty B	5	10
	78 %	56 %

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, 2016	2015
Regulatory assets:			
Price risk management (2)	6 years	$ 146	$ 280
Pension and other postretirement plans (2)	(3)	235	239
Deferred income taxes (2)	(4)	89	89
Deferred broker settlements (2)	6 years	—	2
Other (5)	Various	44	30
Total regulatory assets		$ 514	$ 640
Regulatory liabilities:			
Trojan decommissioning activities	3 years	18	33
Asset retirement obligations (6)	(4)	49	45
Other	Various	31	29
Total regulatory liabilities		$ 98	$ 107

(1) As of December 31, 2016.
(2) Does not include a return on investment.
(3) Recovery expected over the average service life of employees.
(4) Recovery expected over the estimated lives of the assets.
(5) Of the total other unamortized regulatory asset balances, a return is recorded on $44 million and $29 million as of December 31, 2016 and 2015, respectively.
(6) Included in rate base for ratemaking purposes.

As of December 31, 2016, PGE had regulatory assets of $44 million earning a return on investment at the following rates: i) $22 million earning a return by inclusion in rate base; ii) $3 million at the approved rate for deferred accounts under amortization, ranging from 1.47% to 2.20%, depending on the year of approval; and iii) $19 million at PGE’s 2016 cost of capital of 7.56%.

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 resulting from property-related timing differences that previously flowed to customers and will be included in customer prices when the temporary differences reverse. For further information, see Note 11, Income Taxes.

Deferred broker settlements consist of transactions that have been financially settled by clearing brokers prior to the contract delivery date. These gains and losses are deferred for future recovery in customer prices during the corresponding contract settlement month.

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. The USDOE settlement proceeds will be returned to customers over a three-year period that began January 1, 2015 and offset amounts previously collected from customers in relation to Trojan 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,	
	2016	**2015**
Trojan decommissioning activities	$ 44	$ 43
Utility plant	105	97
Non-utility property	12	11
Asset retirement obligations	$ 161	$ 151

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 agreed to reimburse the Plaintiffs $81 million for costs incurred through 2015 resulting from USDOE delays in accepting spent nuclear fuel. The Plaintiffs have received cumulative cash reimbursements of $79 million and expect to receive $2 million in 2017.

PGE has received proceeds of $50 million related to its share in this legal matter and expects to receive $1 million in 2017. 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.

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 2016, the Company recorded an overall increase in AROs, including Trojan, of $9 million, with the change comprised of an increase to revisions in estimated cash flows and incurred liabilities of $6 million, accretion of $6 million, and a reduction of $3 million due to settled liabilities.

In 2016, PGE decreased its ARO related to Boardman by $3 million due to changes in the timing of estimated settlement, with corresponding decreases in the cost basis of the plant, included in Utility Plant, net on the Comparative Balance Sheet. In 2015, PGE increased its ARO related to Boardman by $9 million, due primarily to changes in timing of estimated settlements and due to the acquisition of additional interests in Boardman. For additional information regarding the Company's interests in Boardman, see Note 15, Jointly-owned Plant.

The United States Environmental Protection Agency (EPA) published a final rule, effective October 19, 2015, that regulates Coal Combustion Residuals (CCRs) under the Resource Conservation and Recovery Act, Subtitle D. The rule imposes extensive new requirements, including location restrictions, design and operating standards, groundwater monitoring and corrective action requirements, and closure and post-closure care requirements on CCR impoundments and landfills that are located on active power plant sites and not closed. The requirements for covered CCR impoundments and landfills under the final rule include commencement or completion of closure activities generally between three and ten years from certain triggering events.

The Boardman coal-fired generating plant (Boardman) produces dry CCRs as a by-product. Disposal of the dry CCRs has historically occurred at an on-site landfill that is permitted and regulated by the State of Oregon under requirements similar to the final EPA rule. PGE has determined that it will continue use of the on-site landfill in compliance with the new rule, and the Company believes the final EPA rule will not have a material effect on operations at Boardman.

In 2016, the Company recorded an increase in the ARO related to Colstrip of $6 million related to updated decommissioning estimates, with a corresponding increase in the cost basis of the plant, included in Utility Plant, net on the Comparative Balance Sheet. Colstrip utilizes wet scrubbers and a number of settlement ponds that will require upgrading or closure to meet new regulatory requirements. As a result, in 2015, the Company recorded an increase to the Colstrip AROs in the amount of $17 million. PGE plans to seek recovery in customer prices of the incremental costs associated with the final EPA rule.

In 2016 and 2015, PGE also recorded an increase in AROs totaling $3 million and $4 million, respectively, related to the Company's Beaver natural gas-fired generating plant (Beaver) and Carty.

Non-utility property primarily represents AROs which 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, 2016	Years Ended December 31, 2015
Balance as of beginning of year	$ 151	$ 116
Liabilities incurred	1	2
Liabilities settled	(3)	(4)
Accretion expense	7	7
Revisions in estimated cash flows	5	30
Balance as of end of year	$ 161	$ 151

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, which is included in Other Special Funds 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, 2016, PGE had a $500 million revolving credit facility scheduled to expire in November 2019.

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 contains a provision that allows for two, one-year extensions subject to approval by the banks, 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, 2016, PGE was in compliance with this covenant with a 51.0% debt to total capital ratio.

The Company has a commercial paper program under which it may issue commercial paper for terms of up to 270 days, 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.

Under the revolving credit facility, as of December 31, 2016, PGE had no borrowings outstanding and there was no commercial paper or letters of credit issued. As a result, as of December 31, 2016, 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 a total of $160 million capacity 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, $56 million of letters of credit was outstanding, as of December 31, 2016.

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, 2018.

Short-term borrowings under these credit facilities and related interest rates were as follows (dollars in millions):

	Years Ended December 31,	
	2016	2015
Average daily amount of short-term debt outstanding	$ 1	$ —
Weighted daily average interest rate *	0.7%	0.6%
Maximum amount outstanding during the year	$ 23	$ 11

* 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,	
	2016	2015
First Mortgage Bonds, rates range from 2.51% to 9.31%, with a weighted average rate of 4.86% in 2016 and 5.29% in 2015, due at various dates through 2048	$ 2,090	$ 2,083
Unsecured term bank loans, variable rates of approximately 1.37% due 2017	150	—
Pollution Control Revenue Bonds, 5% rate, due 2033	142	142
Pollution Control Revenue Bonds owned by PGE	(21)	(21)
Total long-term debt	$ 2,361	$ 2,204

First Mortgage Bonds and Unsecured term bank loans—During 2016, PGE issued a total of $140 million of FMBs and repaid long-term debt, in an aggregate amount of $133 million.

In January 2016, the Company issued $140 million of 2.51% Series FMBs due 2021 and repaid $58 million of 3.81% Series FMBs, due in 2017 and $75 million of 5.80% Series FMBs due in 2018. Due to the anticipated repayment of this $133 million in early January 2016, this amount of long-term debt was classified as current on the Company's Comparative Balance Sheet as of December 31, 2015.

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 May 2016, PGE entered into an unsecured credit agreement with certain financial institutions, under which the Company had the opportunity to obtain three separate term loans in an aggregate principal amount of up to $200 million by October 31, 2016. Under the agreement, PGE obtained the following term loans:

- $50 million on May 4, 2016;
- $75 million on June 15, 2016; and
- $25 million on October 31, 2016.

The term loan interest rates are 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, approximately 1.37% as of December 31, 2016, with no other fees.

The credit agreement expires November 30, 2017, at which time any amounts outstanding under the term loans become due and payable. Upon the occurrence of certain events of default, the Company's obligations under the credit agreement may be accelerated. Such events of default include payment defaults to lenders under the credit agreement, covenant defaults and other customary defaults for financings of this type.

Pollution Control Revenue Bonds—The Company has the option to remarket through 2033 the $21 million of PCBs held by PGE as of December 31, 2016. 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, 2016, the future minimum principal payments on long-term debt are as follows (in millions):

Years ending December 31:		
2017	$	150
2018		—
2019		300
2020		—
2021		160
Thereafter		1,751
	$	2,361

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 made no contributions to the pension plan in 2016 or 2015. PGE expects to contribute $3 million to the pension plan in 2017.

In 2014, the Company offered certain eligible participants in the pension plan the option to select a lump sum distribution. As a result of this offering, PGE made lump sum distributions totaling $16 million on July 1, 2014.

Other Postretirement Benefits—PGE has non-contributory postretirement health and life insurance plans, as well as Health Reimbursement Accounts (HRAs) for its employees (collectively, "Other Postretirement Benefits" in the following tables). Employees 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.

Contributions to the HRAs provide for claims by retirees for qualified medical costs. For bargaining employees employed as of April 9, 2004, the participants' accounts are credited with 58% of the value of the employee's accumulated sick time, a stated amount per compensable hour worked, plus 100% of their earned time off accumulated at the time of retirement. For active non-bargaining employees, the Company grants a fixed dollar amount that will become available for qualified medical expenses upon their retirement.

Non-Qualified Benefit Plans—The non-qualified benefit plans (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 include pension make-up benefits for employees that participate in the unfunded Management Deferred Compensation Plan (MDCP). Investments in a non-qualified benefit plan 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 non-qualified benefit plans is December 31.

Other NQBP—In addition to the non-qualified benefit plans 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 non-qualified benefit plan 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):

	2016			2015		
	NQBP	Other NQBP	Total	NQBP	Other NQBP	Total
Non-qualified benefit plan trust	$ 16	$ 18	$ 34	$ 15	$ 18	$ 33
Non-qualified benefit plan liabilities	27	80	107	27	81	108

See "*Trust Accounts*" in Note 3, Comparative Balance Sheet Components, for information on the Non-qualified benefit plan trust.

Investment Policy and Asset Allocation—The Board of Directors of PGE appoints an Investment Committee, which is comprised of officers of the Company, and establishes the Company's asset allocation. The Investment Committee is then responsible for implementation and oversight of the asset allocation. 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. The commitments to each class are controlled by an asset deployment and cash management strategy that takes profits from asset classes whose allocations have shifted above their target ranges to fund benefit payments and investments in asset classes whose allocations have shifted below their target ranges.

The asset allocations for the plans, and the target allocation, are as follows:

	As of December 31,			
	2016		2015	
	Actual	Target *	Actual	Target *
Defined Benefit Pension Plan:				
Equity securities	68 %	67 %	67 %	67 %
Debt securities	32	33	33	33
Total	100 %	100 %	100 %	100 %
Other Postretirement Benefit Plans:				
Equity securities	60 %	62 %	60 %	64 %
Debt securities	40	38	40	36
Total	100 %	100 %	100 %	100 %
Non-Qualified Benefits Plans:				
Equity securities	15 %	11 %	15 %	14 %
Debt securities	7	11	7	8
Insurance contracts	78	78	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 Non-Qualified Benefit Plans, 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 Non-Qualified Benefit Plans, 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.

Pursuant to the adoption of ASU 2015-07, *Fair Value Measurement (Topic 820), Disclosures for Investments in Certain Entities that Calculate Net Asset Value per share (or Its Equivalent)*, as disclosed in Note 2, Summary of Significant Accounting Policies, 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. As required by this ASU, prior period amounts have been retrospectively reclassified to conform to current presentation, including all of the investments previously classified as Level 3. As a result, the Level 3 reconciliation is no longer applicable for such investments and has been excluded from this footnote.

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, 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
As of December 31, 2015:					
Defined Benefit Pension Plan assets:					
Equity securities—Domestic	$ 44	$ —	$ —	$ —	$ 44
Investments measured at NAV:					
Money market funds	—	—	—	5	5
Collective trust funds	—	—	—	479	479
Private equity funds	—	—	—	22	22
	$ 44	$ —	$ —	$ 506	$ 550
Other Postretirement Benefit Plans assets:					
Money market funds	$ —	$ —	$ —	$ —	$ —
Equity securities:					
Domestic	—	3	—	—	3
International	8	—	—	—	8
Debt securities—Domestic government	—	5	—	—	5
Investments measured at NAV:					
Money market funds	—	—	—	7	7
Collective trust funds	—	—	—	7	7
	$ 8	$ 8	$ —	$ 14	$ 30

* Assets are measured at NAV as a practical expedient and not subject to hierarchy level classification disclosure, and have been retrospectively reclassified pursuant to the implementation of ASU 2015-07. For further information see Note 2, Summary of Significant Accounting Policies.

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 not 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 non-qualified benefit plans as of and for the years ended December 31, 2016 and 2015. 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	
	2016	2015	2016	2015	2016	2015
Benefit obligation:						
As of January 1	$ 758	$ 777	$ 81	$ 83	$ 27	$ 27
Service cost	16	18	2	2	—	—
Interest cost	33	31	4	3	1	1
Participants' contributions	—	—	2	2	—	—
Actuarial (gain) loss	26	(31)	(11)	(4)	1	1
Contractual termination benefits	—	—	—	1	—	—
Benefit payments	(34)	(35)	(5)	(6)	(2)	(2)
Administrative expenses	(2)	(2)	—	—	—	—
As of December 31	$ 797	$ 758	$ 73	$ 81	$ 27	$ 27
Fair value of plan assets:						
As of January 1	$ 550	$ 591	$ 30	$ 32	$ 15	$ 15
Actual return on plan assets	45	(4)	1	(2)	1	—
Company contributions	—	—	2	4	2	2
Participants' contributions	—	—	2	2	—	—
Benefit payments	(34)	(35)	(5)	(6)	(2)	(2)
Administrative expenses	(2)	(2)	—	—	—	—
As of December 31	$ 559	$ 550	$ 30	$ 30	$ 16	$ 15
Unfunded position as of December 31	$ (238)	$ (208)	$ (43)	$ (51)	$ (11)	$ (12)
Accumulated benefit plan obligation as of December 31	$ 714	$ 681	N/A	N/A	$ 27	$ 27
Classification in Comparative Balance Sheet:						
Noncurrent asset	$ —	$ —	$ —	$ —	$ 16	$ 15
Current liability	—	—	—	—	(2)	(2)
Noncurrent liability	(238)	(208)	(43)	(51)	(25)	(25)
Net liability	$ (238)	$ (208)	$ (43)	$ (51)	$ (11)	$ (12)
Amounts included in comprehensive income:						
Net actuarial loss (gain)	$ 21	$ 13	$ (10)	$ —	$ 1	$ 1
Amortization of net actuarial loss	(14)	(20)	—	(1)	(1)	(1)
Amortization of prior service cost	—	—	(1)	(1)	—	—
	$ 7	$ (7)	$ (11)	$ (2)	$ —	$ —
Amounts included in AOCL*:						
Net actuarial loss (gain)	$ 236	$ 228	$ (2)	$ 9	$ 13	$ 13
Prior service cost	—	—	1	1	—	—
	$ 236	$ 228	$ (1)	$ 10	$ 13	$ 13

Assumptions used:						
Discount rate for benefit obligation	4.17%	4.36%	3.75%-4.23%	3.90%-4.45%	4.17%	4.36%
Discount rate for benefit cost	4.36%	4.02%	3.90%-4.45%	3.07%-4.10%	4.36%	4.02%
Weighted average rate of compensation increase for benefit obligation	3.65%	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%	6.29%	N/A	N/A
Long-term rate of return on plan assets for benefit cost	7.50%	7.50%	6.29%	6.37%	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	
	2016	2015	2016	2015	2016	2015
Service cost	$ 16	$ 18	$ 2	2	$ —	$ —
Interest cost on benefit obligation	33	31	4	3	1	1
Expected return on plan assets	(40)	(40)	(2)	(2)	—	—
Amortization of prior service cost	—	—	1	1	—	—
Amortization of net actuarial loss	14	20	—	1	1	1
Net periodic benefit cost	$ 23	$ 29	$ 5	$ 5	$ 2	$ 2

PGE estimates that $15 million will be amortized from AOCL into net periodic benefit cost in 2017, consisting of a net actuarial loss of $13 million for pension benefits, $1 million for non-qualified benefits, and $1 million for prior service costs for other postretirement 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					
	2017	2018	2019	2020	2021	2022 - 2026
Defined benefit pension plan	$ 37	$ 39	$ 40	$ 42	$ 43	$ 229
Other postretirement benefits	5	5	5	4	5	22
Non-qualified benefit plans	3	2	3	2	2	10
Total	$ 45	$ 46	$ 48	$ 48	$ 50	$ 261

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 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% in 2023; and
- For 2015, 6.5% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2016, decreasing to 6.0% in 2017, then decreasing 0.25% per year thereafter, reaching 5% in 2021.

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 $19 million in 2016 and $17 million in 2015.

NOTE 11: INCOME TAXES

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

	Years Ended December 31, 2016	2015
Current:		
Federal	$ 10	$ 4
State and local	3	1
	13	5
Deferred:		
Federal	23	26
State and local	14	14
	37	40
Income tax expense	$ 50	$ 45

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,	
	2016	**2015**
Federal statutory tax rate	35.0%	35.0%
Federal tax credits *	(18.2)	(19.0)
State and local taxes, net of federal tax benefit	4.8	4.2
Flow through depreciation and cost basis differences	0.2	—
Other	(1.2)	0.5
Effective tax rate	20.6%	20.7%

* 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. The PTCs are generated for 10 years from the corresponding facility's in service date. PGE's PTCs end at various dates between 2017 and 2024.

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

	As of December 31,	
	2016	**2015**
Accumulated Deferred Income Tax Assets:		
Employee benefits	$ 181	$ 171
Price risk management	68	116
Regulatory liabilities	29	42
Tax credits	56	46
Depreciation and amortization	(3)	(23)
Other	26	18
Total Accumulated Deferred Income Tax Assets	357	370
Accumulated Deferred Income Tax Liabilities:		
Depreciation and amortization	825	781
Regulatory assets	171	220
Price risk management	9	4
Employee benefits	1	1
Other	20	18
Total Accumulated Deferred Income Tax Liabilities	1,026	1,002
Accumulated Deferred Income Tax Liability, net	$ (669)	$ (632)

As of December 31, 2016, PGE has federal credit carryforwards of $56 million, which will expire at various dates through 2036.

PGE believes that it is more likely than not that its deferred income tax assets as of December 31, 2016 and 2015 will be realized; accordingly, no valuation allowance has been recorded. As of December 31, 2016 and 2015, 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

Equity Forward Sale Agreement

PGE entered into an equity forward sale agreement (EFSA) in connection with a public offering of 11,100,000 shares of its common stock in June 2013. In 2013, the Company issued 700,000 shares of its common stock pursuant to the EFSA for net proceeds of $20 million. During the second quarter 2015, PGE physically settled in full the EFSA by issuing 10,400,000 shares of common PGE common stock in exchange for cash of $271 million.

Prior to settlement, the potentially issuable shares pursuant to the EFSA were reflected in PGE’s diluted earnings per share calculations using the treasury stock method. Under this method, the number of shares of PGE’s common stock used in calculating diluted earnings per share for a reporting period were increased by the number of shares, if any, that would be issued upon physical settlement of the EFSA less the number of shares that could have been purchased by PGE in the market with the proceeds received from issuance (based on the average market price during that reporting period).

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 purchase shares of PGE common stock at a price equal to 95% of the fair value of the stock on the purchase date, the last day of the offering period. As of December 31, 2016, there were 369,419 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, 2016, there were 2,474,164 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, and 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, 2014	463,893	28.96
Granted	181,797	34.77
Forfeited	(14,988)	34.10
Vested	(187,709)	25.82
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

A total of 4,687,500 shares of common stock were registered for issuance under the Plan, of which 3,305,920 shares remain available for future issuance as of December 31, 2016.

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, 2016 and 2015.

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; and iii) a relative total shareholder return (TSR) of PGE's common stock as compared to the Edison Electric Institute Regulated Index (EEI Index) 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. 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:

	2016	2015
Risk-free interest rate	0.9%	1.0%
Expected dividend yield	—%	—%
Expected term (in years)	3.0	3.0
Volatility	14.5% - 25.9%	13.2% - 19.2%

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 121.2% and 117.3% of awarded performance-based RSUs for the respective 2016 and 2015 grants, with an estimated 5% forfeiture rate.

The total value of performance-based RSUs vested was $5 million for the year ended December 31, 2016, $4 million for 2015, and $3 million for 2014.

Stock-based compensation, included in Administrative and General Expenses in the Statement of Income, was $6 million for the years ended December 31, 2016 and 2015. 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 $2 million in 2016 and 2015.

As of December 31, 2016, unrecognized stock-based compensation expense was $6 million, of which approximately $4 million and $2 million is expected to be expensed in 2017 and 2018, 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, 2016 and 2015.

NOTE 14: COMMITMENTS AND GUARANTEES

Purchase Commitments

As of December 31, 2016, PGE's estimated future minimum payments pursuant to purchase obligations for the following five years and thereafter are as follows (in millions):

	Payments Due						
	2017	**2018**	**2019**	**2020**	**2021**	**Thereafter**	**Total**
Capital and other purchase commitments	$ 176	$ 8	$ 2	$ 9	$ 1	$ 60	$ 256
Purchased Power:							
Electricity purchases	221	157	181	256	239	1,750	2,804
Capacity contracts	7	6	5	4	4	12	38
Public utility districts	4	4	1	—	1	11	21
Natural gas	53	39	32	27	24	158	333
Coal and transportation	17	9	5	—	—	—	31
Total	$ 478	$ 223	$ 226	$ 296	$ 269	$ 1,991	$ 3,483

Capital and other purchase commitments—Certain commitments have been made for 2017 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 2049, and power capacity contracts through 2024.

Public utility districts—PGE has long-term power purchase agreements with certain public utility districts in the state of Washington and with the City of Portland, Oregon. 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. The future minimum payments for the public utility districts in the preceding table reflect the principal payment 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, 2016	PGE's Share as of December 31, 2016		Contract Expiration	PGE Cost, including Debt Service	
		Output	**Capacity**		**2016**	**2015**
			(in MW)			
Priest Rapids and Wanapum	$ 1,190	8.6%	163	2052	$ 16	$ 18
Wells	177	19.4	150	2018	10	10
Portland Hydro	—	100.0	36	2017	1	2

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. 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, 2016, 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**
2017	$ 7	$ —	$ 10
2018	7	4	9
2019	6	14	6
2020	6	13	6
2021	6	13	7
Thereafter	77	237	177
Total minimum lease payments	$ 109	$ 281	$ 215
Less imputed interest	55		
Present value of net minimum lease payments	$ 54		
Less current portion	3		
Non-current portion	$ 51		

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, 2016, a capital lease asset of $57 million was reflected within Utility Plant and accumulated amortization of such assets of $3 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 $3 million within Obligations Under Capital Leases - Current and $51 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 expense of $3 million was capitalized to CWIP. Beginning August 1, 2016, amortization of the leased asset of $1 million and interest expense of $2 million has been recorded to Purchased Power in the Statement of Income through December 31, 2016.

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 $128 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 $21 million to CWIP and a corresponding liability for the same amount to Other Deferred Credits 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 $10 million in 2016 and 2015.

The future minimum operating lease payments presented is net of sublease income of $4 million in each of 2017, 2018, 2019, and 2020; and $3 million in 2021. Sublease income was $4 million in 2016 and $3 million in 2015.

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, 2016, 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, 2016, 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	$ 680	$ 566	$ —
Colstrip	20.00	1986	528	342	9
Pelton/Round Butte	66.67	1958 / 1964	255	63	5
Total			$ 1,463	$ 971	$ 14

* 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

Construction Litigation—In 2013, the Company entered into an agreement (Construction Agreement) with its engineering, procurement and construction contractor - Abeinsa EPC LLC, Abener Construction Services, LLC, Teyma Construction USA, LLC, and Abeinsa Abener Teyma General Partnership, an affiliate of Abengoa S.A. (collectively, the “Contractor”) - for the construction of Carty, a baseload natural gas-fired generating plant in Eastern Oregon, located adjacent to Boardman. Liberty Mutual Insurance Company and Zurich American Insurance Company (hereinafter referred to collectively as the “Sureties”) provided a performance bond of $145.6 million (Performance Bond) under the Construction Agreement.

On December 18, 2015, the Company declared the Contractor in default under the Construction Agreement and terminated the Construction Agreement. Following termination of the Construction Agreement, PGE, in consultation with the Sureties, brought on new contractors and construction resumed during the week of December 21, 2015.

On January 28, 2016, the Company received notice from the International Chamber of Commerce (ICC) International Court of Arbitration that Abengoa S.A. had submitted a request for arbitration. In the request, Abengoa S.A. alleged that the Company’s termination of the Construction Agreement was wrongful and in breach of the agreement terms and does not give rise to any liability of Abengoa S.A. under the terms of a guaranty in favor of PGE and pursuant to which Abengoa S.A. agreed to guaranty certain obligations of the Contractor under the Construction Agreement. PGE disagrees with the assertions in the request for arbitration and on February 29, 2016 filed a complaint and motion for preliminary injunction in the U.S. District Court for the District of Oregon seeking to have the arbitration claim dismissed on the grounds that the Company has not made a demand under the Abengoa S.A. guaranty, and therefore the matter is not ripe for arbitration.

On March 28, 2016, Abengoa S.A. and several of its foreign affiliates filed petitions for recognition under Chapter 15 of the U.S. Bankruptcy Code requesting interim relief, including an injunction precluding the prosecution of any proceedings against the Chapter 15 debtors. On March 29, 2016, a number of Abengoa S.A.’s U.S. subsidiaries, including the four entities that collectively comprise the Contractor, filed voluntary petitions for relief under Chapter 11 of the U.S. Bankruptcy Code. As a result, on April 5, 2016, the U.S. District Court issued an order stating that the Company’s District Court action against Abengoa S.A. was stayed. In early October 2016, the bankruptcy court in the Chapter 11 proceeding granted the Company’s motion for relief from stay with respect to the four entities that collectively comprise the Contractor, which allows the Company to bring claims against such entities in the U.S. District Court. On October 21, 2016, PGE filed a complaint in the U.S. District Court for the District of Oregon against Abeinsa for failure to satisfy its obligations under the Construction Agreement. PGE is seeking damages from Abeinsa 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.

On March 9, 2016, the Sureties delivered a letter to the Company denying liability in whole under the Performance Bond. In the letter, the Sureties make the following assertions in support of their determination:

1. that, because Abengoa S.A. has alleged that PGE wrongfully terminated the Construction Agreement, PGE must disprove such claim as a condition precedent to recovery under the Performance Bond; and

2. that, irrespective of the outcome of the foregoing wrongful termination claim, the Sureties have various contractual and equitable defenses to payment and are not liable to PGE for any amount under the Performance Bond.

The Company disagrees with the foregoing assertions and, on March 23, 2016, filed a breach of contract action against the Sureties in the U.S. District Court for the District of Oregon. 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.

On April 15, 2016, the Sureties filed a motion to stay this U.S. District Court proceeding, alleging that PGE's claims should be addressed in the arbitration proceeding initiated by Abengoa S.A. and referenced above because PGE's claims are intertwined with the issues involved in such arbitration and all parties necessary to resolve PGE's claims are parties to the arbitration. PGE opposed the motion and filed a motion to enjoin the Sureties from pursuing, in the ICC arbitration proceeding, claims relating to the Performance Bond. On July 27, 2016, the court denied the Sureties' motion to stay and granted PGE's motion for a preliminary injunction. The Sureties appealed the rulings to the Ninth Circuit Court of Appeals. On December 13, 2016, the Ninth Circuit issued an Order staying the district court proceeding, pending a decision on the Sureties' appeal. Oral argument on the Sureties' appeal is scheduled for May 2017.

Recovery of Capital Costs in Excess of $514 million—Following termination of the Construction Agreement, PGE brought on new contractors and resumed construction. Carty was placed into service on July 29, 2016 and the Company began including its revenue requirement, based on the approved cost of $514 million, in customer prices on August 1. Costs for Carty have exceeded the $514 million approved for inclusion in customer prices by the OPUC. 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, determining the remaining scope of construction, preparing work plans for contractors, identifying new contractors, negotiating contracts, and procuring additional materials. Costs also increased as a result of PGE's discovery through the construction process of latent defects in work performed by the former Contractor and the corresponding labor and materials required to correct the work. 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 resulting from poor storage and maintenance on the part of the former Contractor.

As of December 31, 2016, PGE has capitalized $634 million for Carty classified as Utility Plant. PGE currently estimates the total cost of Carty will be approximately $640 million. This cost estimate does not reflect any offsetting amounts that may be received from the Sureties pursuant to the Performance Bond. This estimate also excludes approximately $17 million of lien claims filed against PGE for goods and services provided under contracts with the former Contractor. The Company believes these liens are invalid and is contesting the claims in the courts.

In the event the total project costs incurred by PGE, net of offsetting amounts that may be received from the Sureties, Abengoa S.A., or the Contractor, exceed the $514 million amount approved by the OPUC for inclusion in customer prices, the Company intends to seek approval to recover the excess amounts in customer prices in a subsequent rate proceeding after exhausting all remedies against the aforementioned parties. 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 would 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 that a portion of the cost of Carty will be disallowed for recovery in customer prices is less than probable. Accordingly, no loss has been recorded to date related to the project.

As actual project costs for Carty exceed $514 million, the Company is incurring a higher cost than what is reflected in the current authorized revenue requirement amount, primarily due to higher depreciation and interest expense. On July 29, 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 GRC proceeding. The Company has requested that the OPUC delay its review of this deferral request until the Company's claims against the Sureties have been resolved. Until such time, the effects of this higher cost are recognized in the Company's results of operations, as a deferral for such amounts would not be considered probable of recovery at this time, in accordance with GAAP. Any amounts approved by the OPUC for recovery under the deferral filing will 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, net in the Comparative Balance Sheet were prudently incurred. There have been no settlement discussions with regulators related to such costs.

EPA Investigation of Portland Harbor

A 1997 investigation by the United States Environmental Protection Agency (EPA) of a segment of the Willamette River known as Portland Harbor revealed significant contamination of river sediments. The EPA subsequently included Portland Harbor on the National Priority List pursuant to the federal Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) 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 (RI) has been completed pursuant to an Administrative Order on Consent (AOC) between the EPA and several PRPs known as the Lower Willamette Group (LWG), which does not include PGE. The LWG has funded the RI and feasibility study (FS) and has stated that it has 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 FS, along with the RI, and these documents 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 alternative 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 $1.05 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 Company anticipates that prior to the commencement of remediation activities, a phase of resampling of the river will be necessary to better refine the remedial design and may impact estimated costs.

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 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, and claims are not concluded until a final remedy for clean-up has been settled. 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.

After the claimed damages at a site are assessed, 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 assigning initial NRDA liability allocations to PRPs, which the Company anticipates will occur throughout the first half of 2017. PGE believes that the Company'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.

On July 15, 2016, the Company filed a deferral application with the OPUC to allow for the deferral of the future environmental remediation costs, as well as, seek authorization to establish a regulatory cost recovery mechanism for such environmental costs. The Company has reached an agreement with OPUC Staff and other parties regarding the details of the recovery mechanism, subject to OPUC final decision, which is expected in the first quarter of 2017. The mechanism, as proposed, would allow the Company to recover incurred environmental expenditures through a combination of third-party proceeds, such as insurance recoveries, and through customer prices, as necessary. The mechanism would establish annual prudency reviews of environmental expenditures and be 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 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 Oregon Supreme Court (OSC) in October 2014.

In 2003, in two separate legal proceedings, lawsuits were filed in Marion County Circuit Court (Circuit Court) against PGE on behalf of two classes of electric service customers. 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 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.

The OSC further stated that if the OPUC determined that it can provide a remedy to PGE's customers, then the class action proceedings may become moot in whole or in part. The OSC added that, if the OPUC determined that it cannot provide a remedy, the court system may have a role to play. The OSC also ruled that the plaintiffs retain the right to return to the Circuit Court for disposition of whatever issues remain unresolved from the remanded OPUC proceedings. In October 2006, the Circuit Court abated the class actions in response to the ruling of the OSC.

In June 2015, based on a motion filed by PGE, the Circuit Court lifted the abatement and in July 2015, the Circuit Court heard oral argument on the Company's motion for Summary Judgment. Following oral argument on PGE's motion for summary judgment, the plaintiffs moved to amend the complaints. On February 22, 2016, the Circuit Court denied the plaintiff's motion to amend the complaint and on March 16, 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.

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.

Pacific Northwest Refund Proceeding

In response to the Western energy crisis of 2000-2001, the FERC initiated, beginning in 2001, a series of proceedings to determine whether refunds are warranted for bilateral sales of electricity in the Pacific Northwest wholesale spot market during the period December 25, 2000 through June 20, 2001. In an order issued in 2003, the FERC denied refunds. Various parties appealed the order to the Ninth Circuit Court of Appeals (Ninth Circuit) and, on appeal, the Ninth Circuit remanded the issue of refunds to the FERC for further consideration.

On remand, in 2011 and thereafter, the FERC issued several procedural orders that established an evidentiary hearing, defined the scope of the hearing, expanded the refund period to include January 1, 2000 through December 24, 2000 for certain types of claims, and described the burden of proof that must be met to justify abrogation of the contracts at issue and the imposition of refunds. Those orders included a finding by the FERC that the *Mobile-Sierra* public interest standard governs challenges to the bilateral contracts at issue in this proceeding, and the strong presumption under *Mobile-Sierra* that the rates charged under each contract are just and reasonable would have to be specifically overcome either by: i) a showing that a respondent had violated a contract or tariff and that the violation had a direct connection to the rate charged under the applicable contract; or ii) a showing that the contract rate at issue imposed an excessive burden or seriously harmed the public interest. The FERC also held that a market-wide remedy was not appropriate, given the bilateral contract nature of the Pacific Northwest spot markets. Refund proponents appealed these procedural orders at the Ninth Circuit. On December 17, 2015, the Ninth Circuit held that the FERC reasonably applied the *Mobile-Sierra* presumption to the class of contracts at issue in the proceedings and dismissed evidentiary challenges related to the scope of the proceeding. Plaintiffs on behalf of the California Energy Resources Scheduling division of the California Department of Water Resources filed a request for rehearing on February 1, 2016. By order issued April 18, 2016, the Ninth Circuit denied Plaintiffs' request for panel rehearing of its decision regarding application of the *Mobile-Sierra* presumption.

In response to the evidence and arguments presented during the hearing, in May 2015, the FERC issued an order finding that the refund proponents had failed to meet the *Mobile-Sierra* burden with respect to all but one respondent. In December 2015, the FERC denied all requests for rehearing of its order. With respect to the remaining respondent, FERC ordered additional proceedings, and in an order issued October 18, 2016, rejected the Plaintiffs' request for refunds from the respondent, finding that the Plaintiffs had not met their Mobile-Sierra burden of proof.

The Company has settled all of the direct claims asserted against it in the proceedings for an immaterial amount. The settlements and associated FERC orders did not fully eliminate the potential for so-called "ripple claims," which have been described by the FERC as "sequential claims against a succession of sellers in a chain of purchases that are triggered if the last wholesale purchaser in the chain is entitled to a refund." As a result of the FERC orders to date, there are only two sellers from whom ripple claims could arise if those orders are overturned on appeal. Both of these sellers have now authorized on-the- record representations that they would not pursue ripple claims if they were required to pay refunds. As a result, the Company does not believe that it will incur any material loss in connection with this matter.

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 (2) [ ] A Resubmission	/ /	End of 2016/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				(7,703,404)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				(218,991)
3	Preceding Quarter/Year to Date Changes in Fair Value				
4	Total (lines 2 and 3)				(218,991)
5	Balance of Account 219 at End of Preceding Quarter/Year				(7,922,395)
6	Balance of Account 219 at Beginning of Current Year				(7,922,395)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				259,094
8	Current Quarter/Year to Date Changes in Fair Value				
9	Total (lines 7 and 8)				259,094
10	Balance of Account 219 at End of Current Quarter/Year				(7,663,301)

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)		(7,704,212)		
2			(218,991)		
3					
4			(218,991)	172,147,958	171,928,967
5	(808)		(7,923,203)		
6	(808)		(7,923,203)		
7			259,094		
8					
9			259,094	192,737,923	192,997,017
10	(808)		(7,664,109)		

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

Comprised of the net amount of the actuarial valuation of $364,985 of non-qualifed benefit plans net of taxes of $(145,994).

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

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

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 2016/Q4

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

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

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	9,640,172,118	9,640,172,118
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)	9,696,992,118	9,696,992,118
9	Leased to Others		
10	Held for Future Use	4,615,275	4,615,275
11	Construction Work in Progress	212,574,352	212,574,352
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	9,914,181,745	9,914,181,745
14	Accum Prov for Depr, Amort, & Depl	4,367,096,860	4,367,096,860
15	Net Utility Plant (13 less 14)	5,547,084,885	5,547,084,885
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	4,110,066,095	4,110,066,095
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	257,030,765	257,030,765
22	Total In Service (18 thru 21)	4,367,096,860	4,367,096,860
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)	4,367,096,860	4,367,096,860

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
					15
					16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
					33

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

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

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22

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 2016/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 (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents	182,591,124	6,465,286
4	(303) Miscellaneous Intangible Plant	373,677,186	26,472,007
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	556,268,310	32,937,293
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	4,161,715	
9	(311) Structures and Improvements	255,816,364	56,284
10	(312) Boiler Plant Equipment	585,545,827	10,515,629
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	189,044,231	
13	(315) Accessory Electric Equipment	55,266,118	10,688
14	(316) Misc. Power Plant Equipment	14,836,071	-299
15	(317) Asset Retirement Costs for Steam Production	64,270,343	3,437,613
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,168,940,669	14,019,915
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	
28	(331) Structures and Improvements	53,251,266	13,262,552
29	(332) Reservoirs, Dams, and Waterways	333,125,124	4,851,700
30	(333) Water Wheels, Turbines, and Generators	60,671,875	7,943,336
31	(334) Accessory Electric Equipment	18,667,254	-8,869
32	(335) Misc. Power PLant Equipment	2,098,575	382,091
33	(336) Roads, Railroads, and Bridges	11,060,463	1,548,356
34	(337) Asset Retirement Costs for Hydraulic Production	5,128	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	484,927,312	27,979,166
36	D. Other Production Plant		
37	(340) Land and Land Rights	48,946	
38	(341) Structures and Improvements	167,744,807	106,534,935
39	(342) Fuel Holders, Products, and Accessories	124,375,373	83,368,011
40	(343) Prime Movers		
41	(344) Generators	1,973,628,247	465,320,567
42	(345) Accessory Electric Equipment	107,477,611	8,635,162
43	(346) Misc. Power Plant Equipment	15,181,874	6,600,068
44	(347) Asset Retirement Costs for Other Production	13,851,275	2,847,162
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	2,402,308,133	673,305,905
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	4,056,176,114	715,304,986

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 2016/Q4

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	11,508,608	
49	(352) Structures and Improvements	19,312,917	1,644,355
50	(353) Station Equipment	275,774,826	49,827,757
51	(354) Towers and Fixtures	48,743,877	
52	(355) Poles and Fixtures	25,714,210	5,108,988
53	(356) Overhead Conductors and Devices	74,757,276	5,108,371
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)	456,132,155	61,689,471
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	23,952,230	235,147
61	(361) Structures and Improvements	39,801,373	2,471,002
62	(362) Station Equipment	472,305,679	17,330,634
63	(363) Storage Battery Equipment	387,216	-2,283
64	(364) Poles, Towers, and Fixtures	349,610,654	19,339,286
65	(365) Overhead Conductors and Devices	587,352,193	18,784,240
66	(366) Underground Conduit	15,385,201	383,551
67	(367) Underground Conductors and Devices	690,312,083	66,758,150
68	(368) Line Transformers	357,878,100	20,138,236
69	(369) Services	416,071,326	7,717,553
70	(370) Meters	149,406,330	8,864,597
71	(371) Installations on Customer Premises	376,133	
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	82,968,394	2,629,218
74	(374) Asset Retirement Costs for Distribution Plant	476,732	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	3,186,283,644	164,649,331
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	9,654,596	94,743
87	(390) Structures and Improvements	119,462,980	8,560,944
88	(391) Office Furniture and Equipment	110,362,929	21,874,203
89	(392) Transportation Equipment	52,188,035	7,484,516
90	(393) Stores Equipment	2,830,641	315,284
91	(394) Tools, Shop and Garage Equipment	15,411,227	2,547,079
92	(395) Laboratory Equipment	9,245,947	512,065
93	(396) Power Operated Equipment	44,897,144	2,700,123
94	(397) Communication Equipment	98,648,845	14,003,157
95	(398) Miscellaneous Equipment	308,112	308,178
96	SUBTOTAL (Enter Total of lines 86 thru 95)	463,010,456	58,400,292
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)	463,075,745	58,400,292
100	TOTAL (Accounts 101 and 106)	8,717,935,968	1,032,981,373
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)	8,717,935,968	1,032,981,373

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
			189,056,410		3
16,771,047			383,378,146		4
16,771,047			572,434,556		5
					6
					7
			4,161,715		8
7,248			255,865,400		9
812,126			595,249,330		10
					11
349,730			188,694,501		12
			55,276,806		13
			14,835,772		14
			67,707,956		15
1,169,104			1,181,791,480		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			6,047,627		27
2,891			66,510,927		28
105,291			337,871,533		29
6,257			68,608,954		30
130,857			18,527,528		31
			2,480,666		32
47,716			12,561,103		33
			5,128		34
293,012			512,613,466		35
					36
			48,946		37
165,339		204,092	274,318,495		38
636,614			207,106,770		39
					40
4,914,210			2,434,034,604		41
494,159			115,618,614		42
		-549,776	21,232,166		43
			16,698,437		44
6,210,322		-345,684	3,069,058,032		45
7,672,438		-345,684	4,763,462,978		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 (2) [ ] A Resubmission	/ /	End of 2016/Q4

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)	Line No.
				47
896		1,792,662	13,300,374	48
			20,957,272	49
565,605		6,712,320	331,749,298	50
2,741			48,741,136	51
95,969		16,845	30,744,074	52
		217,926	80,083,573	53
				54
				55
			286,332	56
			34,109	57
665,211		8,739,753	525,896,168	58
				59
52,490		-1,769,306	22,365,581	60
103,881		-186,288	41,982,206	61
2,388,926		-391,310	486,856,077	62
			384,933	63
2,054,563		-2,069,746	364,825,631	64
1,337,495		-709,314	604,089,624	65
			15,768,752	66
43,926		-3,001,537	754,024,770	67
423,048			377,593,288	68
351,538		-39,546	423,397,795	69
1,789,086			156,481,841	70
			376,133	71
				72
107,535			85,490,077	73
			476,732	74
8,652,488		-8,167,047	3,334,113,440	75
				76
				77
				78
				79
				80
				81
				82
				83
				84
				85
			9,749,339	86
1,621,382		-203,667	126,198,875	87
9,277,684			122,959,448	88
2,492,227		3,469,229	60,649,553	89
24,447			3,121,478	90
901,146			17,057,160	91
1,202,955			8,555,057	92
4,352,790		-3,469,229	39,775,248	93
314,763			112,337,239	94
			616,290	95
20,187,394		-203,667	501,019,687	96
				97
			65,289	98
20,187,394		-203,667	501,084,976	99
53,948,578		23,355	9,696,992,118	100
				101
				102
				103
53,948,578		23,355	9,696,992,118	104

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

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

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
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 (2) [ ] A Resubmission	/ /	End of 2016/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	North Bethany, Washington County, OR	2014	2018	538,078
6				
7	Other Land and Land Rights	Various	Various	381,171
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			4,615,275

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 2016/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	63,573,308
2	Mist Natural Gas Storage	21,171,864
3	Construct Marquam Substation	20,536,254
4	Horizon Substation Phase II Project	13,850,922
5	Blue Lake/Gresham - System Upgrades	10,074,462
6	Colstrip Coal Capital Project	9,391,126
7	Field Voice Communications System	7,051,531
8	Customer Substation Upgrade	5,218,190
9	Abernethy Substation Capacity Addition	4,982,451
10	Energy Market Readiness Software Project	4,691,393
11	Canemah-Sullivan 57kV Project	3,773,705
12	West Union - 115kV Conversion	3,694,643
13	Clackamas Protection Mitigation Enhancement	3,527,832
14	Harborton Reliability Project	2,784,369
15	West Side Hydro Structural/Reliability Upgrades	2,677,468
16	Pelton Round Butte Mitigation Enhancement Fund	2,664,879
17	Replace and Rewind Failed Substation Transformers	2,289,722
18	Upgrade and Add Revenue Quality Meters	1,980,277
19	Customer Underground Primary Service	1,828,007
20	Substation TASNET SCADA System Replacement	1,767,525
21	River District Infrastructure - Install Vaults and Conduits	1,550,333
22	Hydro Control System Upgrade	1,388,385
23	PeopleSoft Human Resource Software System Upgrade	1,176,530
24	Rivergate North Substation Rebuild	1,143,666
25	Substation Arc Flash Mitigation	1,076,653
26	Application Segmentation Software	1,041,347
27	Distribution System Construction	1,018,585
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38	Minor Projects, < $1,000,000, represents 8% of Total Construction Work in Progress Balance	16,648,925
39		
40		
41		
42		
43	TOTAL	212,574,352

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 $128 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 $21 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, 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.

Schedule Page: 216 Line No.: 6 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.: 16 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 (2) [ ] A Resubmission	/ /	End of 2016/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	3,867,871,335	3,867,871,335		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	266,415,570	266,415,570		
4	(403.1) Depreciation Expense for Asset Retirement Costs	7,087,268	7,087,268		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	4,305,150	4,305,150		
7	Other Clearing Accounts	270,298	270,298		
8	Other Accounts (Specify, details in footnote):				
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	278,078,286	278,078,286		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	37,124,145	37,124,145		
13	Cost of Removal	-1,977,363	-1,977,363		
14	Salvage (Credit)	-1,766,863	-1,766,863		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	36,913,645	36,913,645		
16	Other Debit or Cr. Items (Describe, details in footnote):	1,030,119	1,030,119		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	4,110,066,095	4,110,066,095		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	901,445,663	901,445,663		
21	Nuclear Production				
22	Hydraulic Production-Conventional	199,660,630	199,660,630		
23	Hydraulic Production-Pumped Storage				
24	Other Production	644,478,097	644,478,097		
25	Transmission	218,580,587	218,580,587		
26	Distribution	1,939,890,596	1,939,890,596		
27	Regional Transmission and Market Operation				
28	General	206,010,522	206,010,522		
29	TOTAL (Enter Total of lines 20 thru 28)	4,110,066,095	4,110,066,095		

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

In January of 2016, PGE acquired the assets and liabilities of SunWay 3, LLC, a variable interest entity, at net book value. The entity was subsequently dissolved.

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 2016/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			-21,682
9	Sub - TOTAL			-11,682
10				
11				
12	SunWay 3, LLC			
13	Paid in Capital	10/19/09		2,415,395
14	Dissolution			
15	Equity in Earnings			-884
16	Sub - TOTAL			2,414,511
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	2,579,954

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 (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
		1,000		2
		176,125		3
		177,125		4
				5
				6
		10,000		7
59,882		38,200		8
59,882		48,200		9
				10
				11
				12
	67,000	2,482,395		13
		-2,481,511		14
		-884		15
	67,000			16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
59,882	67,000	225,325		42

Schedule Page: 224 Line No.: 16 Column: g

In January 2016, PGE acquired the assets and liabilities of SunWay 3, LLC, a variable interest entity, at net book value. The entity was subsequently dissolved.

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 2016/Q4

MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	37,743,684	29,885,835	Generation
2	Fuel Stock Expenses Undistributed (Account 152)		2,656,990	Generation
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	9,638,431	12,994,979	Distribution
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	21,101,321	23,418,346	Generation
8	Transmission Plant (Estimated)	266,663	268,531	Transmission
9	Distribution Plant (Estimated)	8,587,718	5,765,001	Distribution
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	264,386	768,904	Power Operations
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	39,858,519	43,215,761	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	4,074,812	4,320,139	
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	81,677,015	80,078,725	

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

Biomass raw material for co-fire test burn.

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

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

Allowances (Accounts 158.1 and 158.2)

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

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2017 No. (d)	2017 Amt. (e)
1	Balance-Beginning of Year	37,198.00		10,030.00	
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	980.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	36,218.00		10,030.00	
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 (2) [ ] A Resubmission	/ /	End of 2016/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.

2018		2019		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
10,031.00		10,033.00		130,140.00		197,432.00		1
								2
								3
				1,321.00		1,321.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						980.00		18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
10,031.00		10,033.00		131,461.00		197,773.00		29
								30
								31
								32
								33
								34
								35
193.15		193.15		4,588.15		6,369.04		36
								37
								38
				193.15		386.30		39
193.15		193.15		4,395.00		5,982.74		40
								41
								42
								43
					4		16	44
								45
								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 (2) [ ] A Resubmission	/ /	End of 2016/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)	2017 No. (d)	2017 Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/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.

2018		2019		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
								1
								2
								3
								4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								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 (2) [ ] A Resubmission	/ /	End of 2016/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						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2016/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)]	Total Amount of Charges	Costs Recognised During Year	WRITTEN OFF DURING YEAR		Balance at End of Year
				Account Charged	Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
21						
22	Abandoned Trojan Nuclear Plant					
23	Decommissioning Costs;	317,069,821	3,435,949	407,254	2,980,585	520,947
24	PGE has the authority to continue					
25	the recovery of the expense in					
26	rates until decommissioning is					
27	complete, as authorized by OPUC					
28	(Order No. 07-015, dtd 1/12/2007)					
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL	317,069,821	3,435,949		2,980,585	520,947

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

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

(2) ($519,415) - 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.

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 2016/Q4

Transmission Service and Generation Interconnection Study Costs

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

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	Other	173	561.7		456
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Schedule Page: 231 Line No.: 22 Column: a

Represents various study costs charged to FERC 561.7 but not assigned to specific studies.

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2016/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	Balance at Beginning of Current Quarter/Year	Debits	CREDITS		Balance at end of Current Quarter/Year
				Written off During the Quarter/Year Account Charged	Written off During the Period Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
1	Tax Benefits Related to Book/Tax Basis Differences	53,622,051		282	110,480	53,511,571
2	Previously Flowed to Customers	35,748,034		283	72,107	35,675,927
3	(Amort. period is based on the lives of the					
4	properties, approximately 25 years.)					
5						
6	Photovoltaic Volumetric Incentive Pilot	1,630,408	7,173,447	407.3	8,693,243	110,612
7	(per OPUC Order No. 10-198 dtd 5/28/2010)					
8	Reauthorized OPUC Order No.15-185 dtd 6/09/2015)					
9	(Amortization period 5/07/2015 - 5/6/2016)					
10						
11	Colstrip Common Facilities (28 year amort. ending	429,527		407.3	322,140	107,387
12	2017, FERC OCA-AD ltr dtd 5/23/1989)					
13						
14	Price Risk Management	280,008,291		555/547	133,714,712	146,293,579
15						
16	Deferred Broker Settlement	1,778,120		254	1,926,471	-148,351
17						
18	Intervenor Funding (original deferral per OPUC	1,119,159	242,419			1,361,578
19	Order No. 03-388 dtd 7/2/2003)					
20						
21	Independent Evaluator Deferral (2011)	(25,589)	25,656	421	64	3
22	(per OPUC Order No. 11-154 dtd 5/10/2011)					
23	(per Advice No. 14-24 dtd 11/12/2014)					
24	(Amortization period 01/01/2015-12/31/2015)					
25						
26	Generation Plant Maintenance Deferral	2,053,476		557	684,492	1,368,984
27	(per OPUC Order no. 08-601 dtd 12/29/2008;					
28	(amortization period: 1/1/2009 - 12/31/2018)					
29						
30	Residential Sch 123 SNA Deferral-2013	118,700	67,886	456	186,586	
31	(reauthorized Advice No.14-20 dtd 10/30/2014)					
32	(amortization period: 6/1/2014-12/31/2015)					
33						
34	Residential Sch 123 SNA Deferral-2015	4		229	4	
35	(authorized per OPUC Order No.15-019 dtd 1/28/2015)					
36						
37	Residual Deferred Account	(251,471)	209,653	182.3	79,553	-121,371
38	(per OPUC Order No. 10-279 dtd 7/23/2010)					
39						
40	Glass Insulator Deferral	3,325,408	846,157	571	61,410	4,110,155
41	(per OPUC Order No. 10-478 dtd 12/17/2010;					
42	UE 215 First Revenue Requirement Stipulation)					
43	Amortization period: 56 years					
44	TOTAL	639,518,308	57,948,535		183,490,937	513,975,906

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 2016/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1						
2	Pension Funding	228,475,266	21,624,463	219	14,289,895	235,809,834
3	Postretirement Funding	10,285,950		219	10,789,338	-503,388
4	(per SFAS No. 158 adopted 12/31/2006;					
5	OPUC Order No. 07-051 dtd 2/12/2007)					
6						
7	Boardman Decommissioning Balancing	565,253	9,051	456/421	251,575	322,729
8	(per Advice No. 11-07 dtd 05/27/2011)					
9						
10	UE 215 Four Capital Projects Deferral-2012 Vintage	(22,668)	22,668			
11	(per OPUC Order No. 10-478 dtd 12/17/2010,					
12	UE 215 Second Revenue Requirement Stipulation)					
13	Approved into amortization as part of UE 262					
14	(per OPUC Order No.13-459 dtd 12/09/2013)					
15	Amortization period: 1/1/2014 - 12/31/2014					
16						
17	UE 215 Four Capital Projects Deferral-2013 Vintage	385,573		Various	385,573	
18	(per OPUC Order No. 10-478 dtd 12/17/2010,					
19	UE 215 Second Revenue Requirement Stipulation)					
20	Approved into amortization per OPUC docket					
21	No.UE-292, Advice No.14-13 dtd 11/12/14)					
22	amortization period: 1/1/2015 - 12/31/2015					
23						
24	Environmental Remediation Deferral	1,550,000		923	1,550,000	
25	(Amortization per OPUC Order No.14-422,					
26	dtd 12/4/14, GRC docket UE-283)					
27	Amortization period 1/1/2015-12/31/2016					
28						
29	Automated Demand Response Cost Recovery Mechanism		1,032,653	242/431	1,032,653	
30	(per OPUC order No 13-059 dtd 2/26/2013					
31	Amortization per Advice No 13-04 dtd 3/8/2013					
32						
33	2013 Lost Revenue Recovery Adjustment (LRRA)	39,136	79,541	456/421	118,677	
34	(reauthorized OPUC Order No.13-044 dtd 2/12/2013)					
35	Amortization period 6/1/2014-12/31/2015					
36						
37	Direct Access Open Enrollment Deferral -2013	9		447.0	9	
38	(per OPUC Docket UE 246					
39	Advice No.12-09 dtd 12/18/2012)					
40	Amortization period 1/1/2014-12/31/2014					
41						
42	IT O&M 2014 Deferral	5,210,400		Various	1,736,800	3,473,600
43	(per OPUC GRC Order No.13-459, dtd 12/9/2013					
44	TOTAL	639,518,308	57,948,535		183,490,937	513,975,906

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 2016/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	S-9 Partial Stipulation)					
2	Amortization period 1/1/2014-12/31/2018					
3						
4	CET 2014 Deferral	4,291,533		903	1,600,000	2,691,533
5	(per OPUC GRC Order No.13-459, dtd 12/9/2013					
6	S-7 Partial Stipulation)					
7	Amortization period 1/1/2014-12/31/2018					
8						
9	Tucannon RAC Deferral	130,148	39,651	456	169,799	
10	(per OPUC GRC UE-283 Order No.14-422, dtd 12/4/14					
11	and Advice No.14-06, dtd 3/31/2014)					
12	Amortization period 7/1/2015-12/31/2015					
13	(per Order No.15-129)					
14						
15	Port Westward Major Maintenance Accrual	2,794,999		553	556,381	2,238,618
16	(per OPUC GRC Order No.13-459, dtd 12/9/2013)					
17						
18	Schedule 110 Energy Efficiency	103	892,289	Various	892,260	132
19	(per OPUC Advice No. 10-01)					
20						
21	TID PPA Prepaid coal unearned revenue	695,200				695,200
22	(per OPUC GRC Order NO. 14-442, UE-283,					
23	and Advice No. 14-03)					
24						
25	CET 2015 Deferral	4,453,264		903	1,330,301	3,122,963
26	(Per OPUC GRC Order NO. 13-459, UE-266,					
27	and Advice NO. 13-03)					
28	(amortization per OPUC Order No. 14-422,					
29	dtd 12/04/2014, 2015 GRC Docket UE-283					
30	amortization period 01/01/2015-12/31/2018)					
31						
32	Direct Access Reg Deferral 2015	670,011		447/431	590,340	79,671
33	(Per OPUC GRC Order No. 15-023, UM 1301)					
34	Amortization period 1/1/16 - 12/31/16					
35						
36	Deferred Cost - Pricing Program (Pricing Pilot)	392,588	719,270			1,111,858
37	(Per OPUC Order No. 15-203 dtd 6/23/15, UM 1708)					
38						
39	Deferred Cost - DLC Thermostat Nest Pilot)	29,076	341,570	908	9,234	361,412
40	(Per OPUC Order No. 15-203 dtd 6/23/15, UM 1708)					
41						
42	PPS Solar - Revenue Requirement Deferral	16,349	3,862	456/431	20,211	
43	(per OPUC Order No. 15-304 dtd 10/02/15,					
44	TOTAL	639,518,308	57,948,535		183,490,937	513,975,906

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 2016/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Docket UM 1724)					
2	Included in Renewable Resources Automatic					
3	Adjustment Clause					
4						
5	Residential Sch123 SNA Deferral-2016		1,420,750	456/421	86,228	1,334,522
6	(Per OPUC Order No. 16-039 dtd 1/26/16)					
7						
8	Small Nonresdiential Sch123 SNA Deferral-2016		672,222	456/421	672,222	
9	(Per OPUC Order No. 16-039 dtd 1/26/16)					
10						
11	CET 2016 Deferral		4,203,610	903	1,558,179	2,645,431
12	(Per OPUC Order No. 13-459, UE-266,					
13	amortization per OPUC GRC UE-294,					
14	amortization period 01/01/2016-12/31/2018)					
15						
16	Direct Access Reg Deferral 2016		693,629			693,629
17	(Per OPUC Order 16-038, UM-1301)					
18						
19	Carty Major Maintenance Accrual		71,223			71,223
20	(Per OPUC Order 15-356, UE-294 dtd 11/03/15)					
21						
22	Gresham Privilege Tax Collection Deferral		6,960,608			6,960,608
23	(Advice No. 17-05, Schedule 134, dtd 02/24/17)					
24						
25	Portland Harbor Enviornmental		10,596,257			10,596,257
26	Remediation Deferral					
27	(Per OPUC Order No. 17-071					
28	, Docket No. UM1789, dtd 03/02/17)					
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	639,518,308	57,948,535		183,490,937	513,975,906

Schedule Page: 232 Line No.: 18 Column: c

Current year reauthorization approved through OPUC Orders:
$19,154 Order 16-082 dtd 3/16/16, Docket UM 1357
$7,551 Order 16-058 dtd 2/25/16, Docket UM 1662
$1,452 Order 16-199 dtd 5/24/16, Docket UM 1719
$18,587 Order 16-312 dtd 8/18/16, UM 1623
$6,996 Order 16-313 dtd 8/18/16, UM 1755
$14,470 Order 16-283 dtd 7/29/16, UM 1623
$3,886 Order 16-281 dtd 7/29/16, UM1719
$4,085 Order 16-356 dtd 9/21/16, Docket UM 1773
$35,180 Order 16-407 dtd 10/20/16, UE308
$37,495 Order 16-431 dtd 11/9/16, UE308
$66,125 Order 16-004 dtd 1/06/16, Docket UM 1357
$27,437 interests accrued in 2016

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

Amounts charged to accounts 470,421 and 182.

Schedule Page: 232.1 Line No.: 42 Column: d

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

Schedule Page: 232.2 Line No.: 18 Column: d

Amounts charged to accounts 407.3,431 and 254.

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 2016/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

Line 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	-303,771	9,489,157	various	9,221,158	-35,772
3						
4	Net Co-owner / Trust Contributi	137,787	95,245,382	various	94,993,610	389,559
5						
6	Deferred Rent - WTC Tenant					
7	amort. through 2021	726,956		418	98,349	628,607
8						
9	Deferred Revolving Credit					
10	Agreement Fees					
11	amort. through 2020	1,100,741		431	258,997	841,744
12						
13	Dispatchable Generation					
14	various amort. periods from					
15	2005 and extending through 2025	10,945,858	2,389,010	903	1,311,638	12,023,230
16						
17	LID Receivable from WTC Tenants					
18	amort. over 20 yrs through 2029	83,849		418	5,989	77,860
19						
20	Utility Property Sales-					
21	Selling Expenses	31,577		254	7,056	24,521
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress	-134,545				87,871
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	12,588,452				14,037,620

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 2016/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	-27,706,907	-7,887,113
3	Regulatory Liabilities	41,636,022	29,205,352
4	Employee Benefits	170,572,407	180,625,427
5	Price Risk Management	116,155,437	67,851,531
6	Tax Credits & NOL's	45,658,519	55,801,050
7	Other	18,577,027	27,078,937
8	TOTAL Electric (Enter Total of lines 2 thru 7)	364,892,505	352,675,184
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)	4,735,392	4,961,379
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	369,627,897	357,636,563

Notes

Line 7 - Other

	Ending Bal 12/31/2015	Ending Bal 12/31/2016
Bad Debt Expense	$ 2,456,610	$ 2,556,475
Deferred Revenue		5,924,751
Nuclear Decommissioning Trust	5,384,206	6,810,149
Renewable Energy Development	5,779,465	6,158,710
Miscellaneous	4,956,746	5,628,852
Total Line 7 - Other	$18,577,027	$27,078,937

Line 17 - Other Non Utility	Ending Bal 12/31/2015	Ending Bal 12/31/2016
Property Related	$4,471,690	$4,710,348
Employee Benefits	263,702	251,031
Total Line 17 - Other Non Utility	$4,735,392	$4,961,379

CAPITAL STOCKS (Account 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Account 201:			
2	Common Stock	160,000,000		
3				
4	Total_Com	160,000,000		
5				
6	Account 204:			
7	No Par Value Cumlative Preferred	30,000,000		
8				
9	Total_Pre	30,000,000		
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

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
88,946,704	1,205,506,206					2
						3
88,946,704	1,205,506,206					4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						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 (2) [ ] A Resubmission	/ /	End of 2016/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 value 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 former parent	8,317,516
21	SUBTOTAL ACCOUNT 211	12,428,737
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
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 (2) [ ] A Resubmission	/ /	End of 2016/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		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	23,113,532

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 2016/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	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	5.80% Series Due 03/01/2018	75,000,000	282,501
14	6.10% Series Due 4/15/2019 - Order No. 09-089 03/16/2009	300,000,000	2,386,224
15			222,000 D
16	5.43% Series Due 5/3/2040 - Order No. 09-245 06/22/2009	150,000,000	1,034,284
17	3.81% Series Due 6/15/2017 - Order No. 09-405 10/08/2009	58,000,000	375,096
18	4.47% Series Due 6/15/2044 - Order No. 13-098 03/26/2013	150,000,000	1,113,047
19	4.47% Series Due 8/14/2043 - Order No. 13-098 03/26/2013	75,000,000	558,740
20	4.84% Series Due 12/15/2048 - Order No. 13-098 03/26/2013	50,000,000	311,154
21	4.74% Series Due 11/15/2042 - Order No. 13-098 03/26/2013	105,000,000	652,029
22	4.39% Series Due 8/15/2045 - Order No. 14-145 04/29/2014	100,000,000	645,383
23	4.44% Series Due 10/15/2046 - Order No. 14-145 04/29/2014	100,000,000	625,030
24	3.51% Series Due 11/15/2024 - Order No. 14-145 04/29/2014	80,000,000	501,502
25	3.55% Series Due 1/15/2030 - Order No. 14-399 11/12/2014	75,000,000	325,296
26	3.50% Series Due 5/15/2035 - Order No. 14-399 11/12/2014	70,000,000	305,128
27	2.51% Series Due 1/6/2021 - Order No. 14-399 11/12/2014	140,000,000	592,932
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	2,344,400,000	20,322,514
33	TOTAL	2,494,483,849	20,367,514

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
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	2,494,483,849	20,367,514

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 2016/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
12/12/2007	03/01/2018	12/12/2007	03/01/2018		72,500	13
04/16/2009	04/15/2019	04/16/2009	04/15/2019	300,000,000	18,300,000	14
						15
11/30/2009	05/03/2040	11/30/2009	05/03/2040	150,000,000	8,145,000	16
06/15/2010	06/15/2017	06/15/2010	06/15/2017		42,968	17
6/27/2013	6/15/2044	6/27/2013	6/15/2044	150,000,000	6,705,000	18
8/29/2013	8/14/2043	8/29/2013	8/14/2043	75,000,000	3,352,500	19
12/16/2013	12/15/2048	12/16/2013	12/15/2048	50,000,000	2,420,000	20
11/15/2013	11/15/2042	11/15/2013	11/15/2042	105,000,000	4,977,000	21
8/15/2014	8/15/2045	8/15/2014	8/15/2045	100,000,000	4,390,000	22
10/15/2014	10/15/2046	10/15/2014	10/15/2046	100,000,000	4,440,000	23
11/17/2014	11/15/2024	11/17/2014	11/15/2024	80,000,000	2,808,000	24
1/15/2015	1/15/2030	1/15/2015	1/15/2030	75,000,000	2,662,500	25
5/15/2015	5/15/2035	5/15/2015	5/15/2035	70,000,000	2,450,000	26
1/6/2016	1/6/2021	1/6/2016	1/6/2021	140,000,000	3,465,194	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
				2,211,400,000	113,690,662	32
				2,361,477,857	114,590,019	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	50,000,000	376,046	3
06/15/2016	11/30/2017	06/15/2016	11/30/2017	75,000,000	472,219	4
10/31/2016	11/30/2017	10/31/2016	11/30/2017	25,000,000	51,092	5
11/16/2009	11/16/2029			77,857		6
				150,077,857	899,357	7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				2,361,477,857	114,590,019	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 (2) [ ] A Resubmission	/ /	End of 2016/Q4

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

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

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	192,737,923
2		
3		
4	Taxable Income Not Reported on Books	
5	Depreciation, Depletion & Amortization	31,633,552
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Price Risk Management and Mark-to-Market	-133,714,714
11	Regulatory Credits	-21,991,096
12	Other (See Footnote)	80,090,033
13		
14	Income Recorded on Books Not Included in Return	
15	Depreciation, Depletion & Amortization	-31,423,921
16	Regulatory Debits	125,125,139
17	Other (See Footnote)	-652,029
18		
19	Deductions on Return Not Charged Against Book Income	
20	Depreciation, Depletion & Amortization	-138,394,442
21	State & Local Tax Deduction	-2,795,123
22	Other (See Footnote)	-3,356,001
23		
24		
25		
26		
27	Federal Tax Net Income	97,259,321
28	Show Computation of Tax:	
29	Normal Federal Current Provision Benefit @ 35%	34,040,762
30	Federal Energy Tax Credit	-25,097,408
31	RTA Adjustment	1,848,979
32	APIC Tax Adjustment	-50
33	Total Federal Income Tax - PGE	10,792,283
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

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

Qualified NDT		3,564,415
Meals & Entertainment		610,144
Political Activity		1,036,435
Bad Debts		249,496
Fines and Penalties		295
Employee Benefits		25,018,745
Federal Tax Expense		33,544,081
Orion Contingent Royalty Payments		(136,234)
Unamortized loss on reacquired debt		(5,965,886)
Stock Incentive Plans		(1,696,564)
State Tax Expense		16,766,684
Deferred Revenue	7,088,828	
Equity In Earnings Difference	9,594	
Miscellaneous		7,098,422
Total Other		80,090,033

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

Key Man Insurance Proceeds	(566,291)
Miscellaneous	(85,738)
Total Other	(652,029)

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

Dividend Received Deduction	(52,000)
IRC Sec. 199 Domestic Production Activities Deduction	(3,086,653)
Evironmental Remediation	294,177
Renewable Energy Initiatives	710,804
Property Tax	(1,243,162)
Miscellaneous	20,833
Total Other	(3,356,001)

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 2016/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) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1	Federal:					
2	FERC Resale/Coord	50,952		669,232	669,232	
3	Income Tax		954,468	10,792,333	11,465,524	128,996
4	Foreign Insurance Excise Tax					
5	FICA (Employer Share)	2,069,286		19,916,365	20,029,748	
6	Unemployment	2,822		127,670	131,836	
7	Power License	464,759	-437,107	2,219,115	2,213,098	
8	Superfund Tax					
9	SUBTOTAL Federal	2,587,819	517,361	33,724,715	34,509,438	128,996
10	State of Montana:					
11	Income Tax		33,624	210,971	145,000	
12	Electric Energy Producers	189,750		697,673	672,079	
13	Property Taxes	3,145,137		7,535,877	6,914,468	
14	SUBTOTAL Montana	3,334,887	33,624	8,444,521	7,731,547	
15	State of Oregon:					
16	Corp Excise Tax		381,883	1,967,683	3,200,000	30,289
17	Property Taxes		27,493,671	55,872,973	56,758,613	
18	City Taxes & Licenses	3,542,718		43,186,221	43,300,133	
19	Public Utility Comm Fees			5,266,033	5,266,033	
20	Department of Energy		985,851	1,995,850	2,068,281	
21	Department of Enviro Quality	481,903		39,996	41,911	
22	Unemployment	57,111		1,695,146	1,695,626	
23	Water Power Fee		945,097	581,276	757,130	
24	Transportation Tax	363,417		1,551,390	1,565,702	
25	Workers Comp Assessment			242,538	242,538	
26	County & City Income Tax		274,301	537,847	319,800	15,098
27	SUBTOTAL Oregon	4,445,149	30,080,803	112,936,953	115,215,767	45,387
28	State of Washington:					
29	Property Taxes	2,277,470		1,640,163	1,904,698	
30	Sales Tax					
31	SUBTOTAL WASHINGTON	2,277,470		1,640,163	1,904,698	
32	State of Wyoming					
33	Sales Tax					
34	SUBTOTAL WYOMING					
35	State of California:					
36	Corporate Franchise Tax		299,114	370,462	329,235	
37	SUBTOTAL California		299,114	370,462	329,235	
38	Canada					
39	Goods & Services Tax					
40	SUBTOTAL Canada					
41	TOTAL	12,645,325	30,930,902	157,116,814	159,690,685	174,383

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
50,952					669,232	2
	1,498,663	11,475,291			-682,958	3
		9,485			-9,485	4
1,955,903		11,443,601			8,472,764	5
-1,344		75,058			52,612	6
317,528	-590,355				2,219,115	7
						8
2,323,039	908,308	23,003,435			10,721,280	9
						10
	-32,347	210,828			143	11
215,344		407,253			290,420	12
3,766,546		5,752,457			1,783,420	13
3,981,890	-32,347	6,370,538			2,073,983	14
						15
	1,583,911	2,113,882			-146,199	16
	28,379,311	51,439,839			4,433,134	17
3,428,806		43,125,386			60,835	18
					5,266,033	19
	1,058,282	1,995,850				20
479,988					39,996	21
56,631		974,312			720,834	22
	1,120,951				581,276	23
349,105		890,149			661,241	24
		139,506			103,032	25
	41,156	540,078			-2,231	26
4,314,530	32,183,611	101,219,002			11,717,951	27
						28
2,012,935		1,640,162			1	29
						30
2,012,935		1,640,162			1	31
						32
						33
						34
						35
	257,887	383,048			-12,586	36
	257,887	383,048			-12,586	37
						38
						39
						40
12,632,394	33,317,459	132,616,185			24,500,629	41

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

Tax payment from subsidiary.

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

Tax payment from subsidiary.

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

Tax payment from subsidiary.

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2016/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 Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%						
6							
7							
8	TOTAL						
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
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 (2) [ ] A Resubmission	/ /	End of 2016/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
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
			34
			35
			36
			37
			38
			39
			40
			41
			42
			43
			44
			45
			46
			47
			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 (2) [ ] A Resubmission	/ /	End of 2016/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	94,164			82,984	177,148
2						
3	Deferred Liability for Transferred	659,254	421	31,401		627,853
4	Non-Qualified Plan Benefits					
5						
6	Reserve for Portland Harbor				7,000,000	7,000,000
7	Enviornmental Remediation Costs					
8						
9	TID PPA prepaid coal stock	2,882,461			738,221	3,620,682
10						
11	Deferral of Precedent Transmission	7,811,493	232	1,702,136		6,109,357
12	Service Agreement with DET, EDF					
13						
14	Northwest Natural Mist Storage				21,171,864	21,171,864
15	Capital Lease Accrual					
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	11,447,372		1,733,537	28,993,069	38,706,904

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	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 2016/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 (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	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

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS						
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
							15
							16
							17
							18
							19
							20
							21

NOTES (Continued)

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	722,917,080	134,378,239	66,928,746
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	722,917,080	134,378,239	66,928,746
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	722,917,080	134,378,239	66,928,746
10	Classification of TOTAL			
11	Federal Income Tax	589,033,301	107,262,809	52,101,388
12	State Income Tax	123,935,590	25,346,275	12,510,969
13	Local Income Tax	9,948,189	1,769,155	2,316,389

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 (2) [ ] A Resubmission	/ /	End of 2016/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		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)	Balance at End of Year (k)	Line No.
							1
		182.3	31,912,351	254	31,801,872	790,256,094	2
							3
							4
			31,912,351		31,801,872	790,256,094	5
							6
							7
							8
			31,912,351		31,801,872	790,256,094	9
							10
			26,148,626		26,083,044	644,129,140	11
			5,205,917		5,280,677	136,845,656	12
			557,808		438,151	9,281,298	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 (2) [ ] A Resubmission	/ /	End of 2016/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 (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 283			
2	Electric			
3	Property Related	35,748,060		
4	Price Risk Management	4,152,121	5,193,714	13,257
5	Regulatory Assets	219,522,884	27,171,487	76,085,175
6	Regulatory Liabilities			
7	Other	18,015,186	2,941,251	987,852
8				
9	TOTAL Electric (Total of lines 3 thru 8)	277,438,251	35,306,452	77,086,284
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other	1,642,971		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	279,081,222	35,306,452	77,086,284
20	Classification of TOTAL			
21	Federal Income Tax	225,412,142	27,827,170	61,579,418
22	State Income Tax	49,648,104	7,034,807	14,017,761
23	Local Income Tax	4,020,976	444,475	1,489,105

NOTES

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

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

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Account Credited	Amount	Account Debited	Amount	Balance at End of Year	Line No.
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
		254	21,199,392	182.3	21,145,559	35,694,227	3
						9,332,578	4
						170,609,196	5
							6
						19,968,585	7
							8
			21,199,392		21,145,559	235,604,586	9
							10
							11
							12
							13
							14
							15
							16
							17
240,972	1,259,725	254	22,224	182.3	3,950	605,944	18
240,972	1,259,725		21,221,616		21,149,509	236,210,530	19
							20
186,991	1,008,020		17,493,145		17,433,656	190,779,376	21
49,739	231,419		3,404,093		3,471,492	42,550,869	22
4,242	20,286		324,378		244,361	2,880,285	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	95,504,486	94,125,025
ASC 980 Mark-to-Market	64,295,252	48,122,715
Regulatory Deferral Earn Test Offset	(1,279,955)	(792,317)
Price Risk Mgmt Deferral	47,708,064	10,396,238
Miscellaneous	13,295,037	18,757,535
Total Regulatory Assets	219,522,884	170,609,196

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

	Balance at Beg. Of Year	Balance at End of Year
Unamortized Loss on Reacquired Debt	6,536,443	8,923,029
Prepaid Property Tax	10,721,896	11,105,739
Other	756,847	(60,183)
Total Other	18,015,186	19,968,585

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

	Balance at Beg. Of Year	Balance at End of Year
Trust-Owned Life Insurance Gain/Loss	393,257	302,025
Reg Deferral Earn Test Offset	1,425,117	792,317
Other	(175,403)	(488,398)
Total Other	1,642,971	605,944

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 2016/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Excess Deferred Taxes	3,036,130			185,706	3,221,836
2						
3	Gain on Asset Sales	2,150,932	407.4/431	436,071	578,469	2,293,330
4	(per OPUC Order No. 01-777 dtd 8/31/2001)					
5						
6						
7						
8	Gain on Tradeable Renewable Energy Credits	1,990,240			44,229	2,034,469
9	(per OPUC Order No. 07-083 dtd 3/5/2007)					
10						
11	Boardman Severance	5,578,157			1,134,176	6,712,333
12	Advice No.14-18, dtd 11/3/2014					
13						
14	Asset Retirement Obligations:	45,077,346	407.3	8,048,122	12,437,599	49,466,823
15	Balancing Account					
16						
17	Coyote Springs Major Maintenance Deferral	3,741,610	456	162,644		3,578,966
18	(per OPUC Order No. 01-777 dtd 8/31/2001;					
19	reauthorization OPUC Order No. 10-478					
20	dtd 12/17/2010)					
21						
22	ISFSI Pollution Control Tax Credit Deferral	1,429,737	431	300,332	23,288	1,152,693
23	(per OPUC Order No. 05-136 dtd 3/15/2005)					
24	(amortization per OPUC Order No.14-422,					
25	dtd 12/04/2014, 2015 GRC Docket UE-283					
26	Amortization period 01/01/2015-12/31/2015)					
27						
28	Zero Interest Program Loan Repayments	2,126,527			280,400	2,406,927
29	(per Advice No. 05-19 dtd 12/20/2005)					
30						
31	Schedule 110 Energy Efficiency - Balancing Accout	371,090			52,325	423,415
32	(per Advice No. 07-25 dtd 5/20/2008)					
33						
34	Sunway 3 Investment Deferral	659,350	407.4	45,480		613,870
35	(per UM 1480 dtd 4/01/2010;					
36	(Amortization over 20 years commencing 2010)					
37						
38	Direct Access Open Enrollment - 2014	(23,451)	182.3	67	23,518	
39	(per Advice 13-25 dtd 11/15/2013)					
40	(amortization per OPUC Advice No.14-24,					
41	TOTAL	106,949,335		31,001,849	22,387,202	98,334,688

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	dtd 11/12/2014)					
2	(Amortization period 01/01/2015-12/31/2015)					
3						
4	Trojan Decommissioning Deferral	31,484,432	407/431	16,340,314	1,610,701	16,754,819
5	(amortization per OPUC Order No.14-422,					
6	dtd 12/04/2014, 2015 GRC Docket UE-283)					
7	(Amortization period 01/01/2015-12/31/2017)					
8						
9	PRC Acquisition	6,135,811	407	2,782,894	22,459	3,375,376
10	(per OPUC UE-283 Final GRC Order No.14-422,					
11	dtd 12/04/2014, Second Partial					
12	Stipulation dtd 09/02/2014)					
13	(amortization per OPUC Advice No.14-24,					
14	dtd 11/12/2014)					
15	(Amortization period 01/01/2015-12/31/2016)					
16						
17	Port Westward 2 LTSA	229,707			680,393	910,100
18	(per OPUC 2015 GRC Docket UE-283,					
19	OPUC Order No.14-422, dtd 12/04/14)					
20						
21	PPS Solar - Deferral of Gain on Sale/Leaseback	2,961,717	456	2,654,649		307,068
22	Property sale/leaseback (approved per OPUC Order					
23	No. 15-237, Docket UP 324 dtd 08/11/15)					
24	Gain deferral and amortization (per OPUC					
25	Order No. 15-304 dtd 10/02/15, Docket UM-1724)					
26	Project approved for inclusion in RRAAC (Sch 122)					
27	(per OPUC Order No. 15-304, Docket UE 297)					
28	(Amortization period 01/01/2016 -12/31/16)					
29						
30	Boardman Co-Fire Biomass Test Burn		456	231,276	2,733,131	2,501,855
31	(per OPUC Order No. 13-280 dtd 8/5/13					
32	Updated Order No. 14-422 dtd 12/4/14)					
33						
34	PPS Solar RRAAC Deferral				25,865	25,865
35	(per OPUC order No. 15-237 dtd 8/11/15					
36	order No. 15-304(UM1724) dtd 10/2/15)					
37						
38	North Fork Surface Collector				249,006	249,006
39	(per OPUC order 15-356 UE294 dtd 11/3/15)					
40						
41	TOTAL	106,949,335		31,001,849	22,387,202	98,334,688

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 2016/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	Deferred Broker Settlement				2,305,937	2,305,937
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	106,949,335		31,001,849	22,387,202	98,334,688

Schedule Page: 278 Line No.: 3 Column: e

Total net credit change in account consists of the following:

Gain and Other
$(288,000) Reversal of unbilled amortization from Dec-2015
$(153,104) Gain on sale of property at St. Mary Station and $(10,900) easement grant
$(99,289) Gain on sale of property at Newberg to ODOT
$(47,488) Interest on Gain
$20,312 Miscellaneous adjustments

Schedule Page: 278.1 Line No.: 9 Column: f

Amount consists of the following:
($3,463,462) - PRC Operating Risk Premium Escrow (for decommissioning in 2020+)
$78,314 - PRC Net Economic Payment
$9,772 - PRC PPA Bookout

($3,375,376) 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 (2) [ ] A Resubmission	/ /	End of 2016/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 (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	837,938,465	845,906,182
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	645,487,072	646,306,478
5	Large (or Ind.) (See Instr. 4)	207,677,973	227,985,121
6	(444) Public Street and Highway Lighting	12,824,132	15,385,088
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,703,927,642	1,735,582,869
11	(447) Sales for Resale	123,165,759	109,756,221
12	TOTAL Sales of Electricity	1,827,093,401	1,845,339,090
13	(Less) (449.1) Provision for Rate Refunds	-7,913,648	-1,197,209
14	TOTAL Revenues Net of Prov. for Refunds	1,835,007,049	1,846,536,299
15	Other Operating Revenues		
16	(450) Forfeited Discounts	2,994,617	3,019,106
17	(451) Miscellaneous Service Revenues	1,852,377	1,796,073
18	(453) Sales of Water and Water Power	-24,166	-22,164
19	(454) Rent from Electric Property	8,704,481	7,608,190
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	82,652,310	47,726,337
22	(456.1) Revenues from Transmission of Electricity of Others	7,980,146	8,257,229
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	104,159,765	68,384,771
27	TOTAL Electric Operating Revenues	1,939,166,814	1,914,921,070

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
7,347,750	7,325,314	752,365	742,467	2
				3
6,860,480	6,918,745	106,553	105,582	4
2,968,238	3,369,215	258	255	5
71,705	83,112	220	220	6
				7
				8
				9
17,248,173	17,696,386	859,396	848,524	10
3,999,098	3,162,844	39	40	11
21,247,271	20,859,230	859,435	848,564	12
				13
21,247,271	20,859,230	859,435	848,564	14

Line 12, column (b) includes $ 29,464,000 of unbilled revenues.
Line 12, column (d) includes 287,427 MWH relating to unbilled revenues

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

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.: 4 Column: c

Includes $12,276,010 in revenue related to the delivery of 508,747 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 2015, 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 $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.: 5 Column: c

Includes $16,330,087 in revenue related to the delivery of 1,176,959 megawatt hours to customers of Energy Services Suppliers (ESSs). For 2015, 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:

Returned Check Charges
Reconnect Charges

Field Service Charges
Meter Tamper Charges
Meter Test Charges
Meter Verification Charges
Revenue for E-Manager & Energy Experts

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

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

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

Other Electric Revenues consist of the following:

	2015
RPA Balancing	54,425,291
Transmission Resale	6,636,684
Steam Sale	2,555,480
Energy Trust Contract	2,162,090
Automated Demand Response Deferred Costs	793,393
Park Revenues	510,531
Gas Resale	(1,172,918)
Tucannon RAC Deferral	(1,355,707)
Boardman Severance	(2,266,836)
Lost Rev Recovery Adj	(3,869,603)
Sch7 Sales Norm Adj	(11,342,675)
Other	650,607
Totals	$ 47,726,337

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 2016/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					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
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 (2) [ ] A Resubmission	/ /	End of 2016/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	11,329	1,298,230	1,260	8,991	0.1146
3	7 Residential Service	7,188,664	819,116,797	751,105	9,571	0.1139
4	15 Outdoor Area Lighting	3,292	1,008,438			0.3063
5	Residential Unbilled Revenue	144,465	16,515,000			0.1143
6	TOTAL Account 440	7,347,750	837,938,465	752,365	9,766	0.1140
7	General Comm. and Ind. Sales:					
8	15 Comm. Outdoor Lighting	13,183	2,560,747			0.1942
9	32 Small Nonresidential	1,584,415	173,376,976	90,248	17,556	0.1094
10	38 Optional Time of Day -	30,372	3,905,713	387	78,481	0.1286
11	Large Nonresidential					
12	47 Irrigation - Drainage - Small	19,247	3,640,501	1,982	9,711	0.1891
13	49 Irrigation - Drainage - Large	60,600	7,933,249	1,042	58,157	0.1309
14	83-S Large Nonresidential	2,779,059	250,857,959	11,335	245,175	0.0903
15	85-S Large Nonresidential	2,259,721	178,776,853	1,244	1,816,496	0.0791
16	89-S Large Nonresidential	1,020	340,566	1	1,020,000	0.3339
17	485-S COS Opt-Out - Lrg. Nonresid		7,873,140	167		
18	489-S COS Opt-Out - Lrg. Nonresid		339,756	1		
19	515-S DAS - Outdoor Area Lighting		9,419			
20	532-S DAS - Small Nonresidential		230,908	70		
21	583-S DAS - Large Nonresidential		931,549	41		
22	585-S DAS - Large Nonresidential		3,489,736	35		
23	Gen Comm. & Ind. Unbilled Revenue	112,863	11,220,000			0.0994
24	TOTAL Account 442 - Small	6,860,480	645,487,072	106,553	64,386	0.0941
25	Large Industrial Power Sales:					
26	75 Partial Requirements Service	6,658	946,169			0.1421
27	89-T Large Nonresidential	64,525	4,757,864	5	12,905,000	0.0737
28	85-P Large Nonresidential	664,620	47,806,211	169	3,932,663	0.0719
29	89-P Large Nonresidential	723,425	47,573,817	17	42,554,412	0.0658
30	90-P Large Nonresidential	1,478,096	89,265,251	4	369,524,000	0.0604
31	489-T COS Opt-Out - Lg. Nonreside		2,522,203	3		
32	485-P COS Opt-Out - Lrg. Nonresid		5,598,466	42		
33	489-P COS Opt-Out - Lg. Nonreside		6,157,658	10		
34	585-P DAS - Large Nonresidential		1,196,334	8		
35	589-P DAS - Large Nonresidential					
36	Large Industrial Unbilled Revenue	30,914	1,854,000			0.0600
37	TOTAL Account 442 - Large	2,968,238	207,677,973	258	11,504,798	0.0700
38	Street Lighting					
39	Various Public Street and					
40	Highway Lighting:					
41	TOTAL Billed	16,960,746	1,674,463,642	859,396	19,736	0.0987
42	Total Unbilled Rev.(See Instr. 6)	287,427	29,464,000	0	0	0.1025
43	TOTAL	17,248,173	1,703,927,642	859,396	20,070	0.0988

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 2016/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	72,520	12,949,132	220	329,636	0.1786
2	Street Lighting Unbilled Rev	-815	-125,000			0.1534
3	TOTAL Account 444	71,705	12,824,132	220	325,932	0.1788
4	TOTAL Account 445					
5	Other Sales to Public Authorities					
6	Communication Devices Electr					
7	TOTAL Account 445					
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	16,960,746	1,674,463,642	859,396	19,736	0.0987
42	Total Unbilled Rev.(See Instr. 6)	287,427	29,464,000	0	0	0.1025
43	TOTAL	17,248,173	1,703,927,642	859,396	20,070	0.0988

Schedule Page: 304 Line No.: 14 Column: a

Rate Schedule 83 complete title: Large Nonresidential Standard Service (31 - 200 kW).

Schedule Page: 304 Line No.: 15 Column: a

Rate schedule 85 complete title: Large Nonresidential Standard Service (201 - 4,000 kW).

Schedule Page: 304 Line No.: 16 Column: a

Rate schedule 89 complete title: Large Nonresidential (>4,000 kW) Standard Service.

Schedule Page: 304 Line No.: 17 Column: a

Rate Schedule 485 complete title: Large Nonresidential (201 - 4,000 kW) Cost of Service Opt-out.

Schedule Page: 304 Line No.: 18 Column: a

Rate Schedule 489 complete title: Large Nonresidential (>4,000 kW) Cost of Service Opt-out.

Schedule Page: 304 Line No.: 20 Column: a

Rate Schedule 532 complete title: Small Nonresidential Direct Access Service.

Schedule Page: 304 Line No.: 21 Column: a

Rate Schedule 583 complete title: Large Nonresidential Direct Access Service (31 - 200 kW).

Schedule Page: 304 Line No.: 22 Column: a

Rate Schedule 585 complete title: Large Nonresidential Direct Access Service (201 - 4,000 kW).

Schedule Page: 304 Line No.: 27 Column: a

Rate schedule 89 complete title: Large Nonresidential (>4,000 kW) Standard Service.

Schedule Page: 304 Line No.: 28 Column: a

Rate schedule 85 complete title: Large Nonresidential Standard Service (201 - 4,000 kW).

Schedule Page: 304 Line No.: 29 Column: a

Rate schedule 89 complete title: Large Nonresidential (>4,000 kW) Standard Service.

Schedule Page: 304 Line No.: 30 Column: a

Rate schedule 90 complete title: Large Nonresidential Standard Service (>4,000 kW and Aggregate to >100 MWa).

Schedule Page: 304 Line No.: 31 Column: a

Rate Schedule 489 complete title: Large Nonresidential (>4,000 kW) Cost of Service Opt-out.

Schedule Page: 304 Line No.: 32 Column: a

Rate Schedule 485 complete title: Large Nonresidential (201 - 4,000 kW) Cost of Service Opt-out.

Schedule Page: 304 Line No.: 33 Column: a

Rate Schedule 489 complete title: Large Nonresidential (>4,000 kW) Cost of Service Opt-out.

Schedule Page: 304 Line No.: 34 Column: a

Rate Schedule 585 complete title: Large Nonresidential Direct Access Service (201 - 4,000 kW).

Schedule Page: 304 Line No.: 35 Column: a

Rate Schedule 589 complete title: Large Nonresidential (>4,000 kW) Direct Access Service.

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 2016/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 Classification	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	ATCO Power	SF	WSPP - 1	NA	NA	NA
3	Avangrid Renewables	SF	EEI	NA	NA	NA
4	Avista Corp	SF	WSPP-1	NA	NA	NA
5	Bonneville Power Administration	SF	WSPP-1	NA	NA	NA
6	Brookfield Energy Marketing LP	SF	WSPP - 1	NA	NA	NA
7	BP Energy Company	SF	PGE-11	NA	NA	NA
8	Burbank, City of	SF	WSPP-1	NA	NA	NA
9	California Independent System Operator	SF	CAISO	NA	NA	NA
10	Calpine Energy Services	SF	EEI	NA	NA	NA
11	Cargill Power Markets, LLC	SF	WSPP-1	NA	NA	NA
12	Chelan County, PUD No. 1, Washington	SF	WSPP-1	NA	NA	NA
13	Citigroup Energy Inc.	SF	WSPP-1	NA	NA	NA
14	Clatskanie County PUD, Washington	SF	WSPP-1	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do 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) (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	Commerce Energy	SF	WSPP-1	NA	NA	NA
2	ConocoPhillips	SF	WSPP - 1	NA	NA	NA
3	CP Energy Marketing	SF	WSPP-1	NA	NA	NA
4	Douglas County, PUD No. 1, Washington	SF	WSPP-1	NA	NA	NA
5	EDF Trading NA	SF	WSPP-1	NA	NA	NA
6	Element Markets	SF	WSPP-1	NA	NA	NA
7	Energy America	SF	WSPP -1	NA	NA	NA
8	ENMAX Energy Mktg	SF	WSPP-1	NA	NA	NA
9	Energy Keepes, Inc	SF	WSPP-1	NA	NA	NA
10	Eugene Water & Electric Board	SF	WSPP-1	NA	NA	NA
11	Exelon	SF	EEI	NA	NA	NA
12	Glendale, City of	SF	WSPP-1	NA	NA	NA
13	Grant County, PUD No. 2, Washington	SF	WSPP-1	NA	NA	NA
14	Gridforce Energy	SF	EEI	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do 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	Idaho Power Company	SF	WSPP-1	NA	NA	NA
2	J Aron Compay	SF	EEI	NA	NA	NA
3	Load Balance Energy	OS	OATT	NA	NA	NA
4	Los Angeles Depart of Water Power	SF	WSPP-1	NA	NA	NA
5	Macquarie Cook Power	SF	WSPP-1	NA	NA	NA
6	Marin Clean Energy	SF	WSPP-1	NA	NA	NA
7	Modesto Irrigation District	SF	WSPP-1	NA	NA	NA
8	Morgan Stanley Capital Group	SF	PGE-11	NA	NA	NA
9	NaturEner	SF	WSPP-1	NA	NA	NA
10	Nevada Power	SF	WSPP-1	NA	NA	NA
11	NextEra Energy Solutions Inc	SF	WSPP-1	NA	NA	NA
12	Noble Americas	SF	WSPP-1	NA	NA	NA
13	NorthWestern Corporation	SF	WSPP-1	NA	NA	NA
14	Okanogan County PUD, Washington	SF	WSPP-1	NA	NA	NA
	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 (2) [ ] A Resubmission	/ /	End of 2016/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	PacifiCorp	LU	PGE-11	NA	NA	NA
2	PacifiCorp	SF	EEI	NA	NA	NA
3	Power and Water Resources	SF	WSPP-1	NA	NA	NA
4	Powerex	SF	EEI	NA	NA	NA
5	Public Service Company of Colorado	SF	WSPP-1	NA	NA	NA
6	Public Utility District No. 1 of Clark	SF	WSPP-1	NA	NA	NA
7	Puget Sound Energy	SF	WSPP-1	NA	NA	NA
8	Rainbow Energy Marketing	SF	WSPP-1	NA	NA	NA
9	Redding, City of	SF	WSPP-1	NA	NA	NA
10	Roseville, City of	SF	WSPP-1	NA	NA	NA
11	Sacramento Municipal Utility Distric	SF	WSPP-1	NA	NA	NA
12	Seattle City Light	SF	WSPP-1	NA	NA	NA
13	Shell Energy NA	SF	PGE-11	NA	NA	NA
14	Snohomish County PUD Washington	SF	WSPP-1	NA	NA	NA
	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 (2) [ ] A Resubmission	/ /	End of 2016/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	Sonoma Clean Power Authority	SF	WSPP-1	NA	NA	NA
2	Southern California Edison	SF	EEI	NA	NA	NA
3	Tacoma, City of	SF	WSPP-1	NA	NA	NA
4	Talen Energy	SF	EEI	NA	NA	NA
5	Tenaska	SF	WSPP-1	NA	NA	NA
6	The Energy Authority	SF	WSPP-1	NA	NA	NA
7	TransAlta Energy Marketing	SF	EEI	NA	NA	NA
8	TransCanada Power	SF	WSPP-1	NA	NA	NA
9	Turlock Boardman Revenue	IF	WSPP-1	NA	NA	NA
10	Turlock Irrigation District	SF	WSPP-1	NA	NA	NA
11	Tuscon Electric Power Company	SF	WSPP-1	NA	NA	NA
12	Vitol Inc.	SF	WSPP-1	NA	NA	NA
13	Western Area Power Authority	SF	WSPP-1	NA	NA	NA
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2016/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) (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	Direct Access Deferral - 2016			NA	NA	NA
2	Direct Access Amortization - 2015			NA	NA	NA
3	Direct Access Amortization - 2014			NA	NA	NA
4	Direct Access Amortization - 2013			NA	NA	NA
5	Carty Test Sales Reclass			NA	NA	NA
6						
7	Portland General Electric Company	SF	OA96137	923	NA	NA
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,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
200		9,600		9,600	2
65,522		1,253,659		1,253,659	3
15,000		241,714		241,714	4
40,367		1,198,454		1,198,454	5
220		7,527		7,527	6
138,075		3,102,828		3,102,828	7
5,206		179,456		179,456	8
1,591,754		38,138,580		38,138,580	9
8,185		252,979		252,979	10
53,038		1,132,917		1,132,917	11
18,003		408,548		408,548	12
45,000		674,200		674,200	13
1,581		28,250		28,250	14
0	0	0	0	0	
4,001,034	5,934,659	117,608,755	-377,655	123,165,759	
4,001,034	**5,934,659**	**117,608,755**	**-377,655**	**123,165,759**	

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 2016/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.
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.
		448,000		448,000	1
2,478		77,072		77,072	2
100		2,550		2,550	3
450		14,201		14,201	4
1,850		1,061,500		1,061,500	5
		312,000		312,000	6
		593,462		593,462	7
410		6,460		6,460	8
24,331		643,025		643,025	9
9,403		171,472		171,472	10
151,402		3,712,604		3,712,604	11
1,651		55,695		55,695	12
		54		54	13
62		2,105		2,105	14
0	0	0	0	0	
4,001,034	5,934,659	117,608,755	-377,655	123,165,759	
4,001,034	**5,934,659**	**117,608,755**	**-377,655**	**123,165,759**	

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.
28,189		750,002		750,002	1
30,795		946,946		946,946	2
1,902			7,149	7,149	3
64,479		7,653,115		7,653,115	4
28,598		609,115		609,115	5
		778,160		778,160	6
11,818		327,196		327,196	7
51,466		1,143,917		1,143,917	8
39		1,045		1,045	9
223		4,183		4,183	10
32,145		761,503		761,503	11
		325,000		325,000	12
87,464		2,607,744		2,607,744	13
943		24,975		24,975	14
0	0	0	0	0	
4,001,034	5,934,659	117,608,755	-377,655	123,165,759	
4,001,034	**5,934,659**	**117,608,755**	**-377,655**	**123,165,759**	

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 2016/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.
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 ($) (h)	REVENUE: Energy Charges ($) (i)	REVENUE: Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
16,965			126,276	126,276	1
81,426		1,749,443		1,749,443	2
		720,000		720,000	3
147,180		3,029,390		3,029,390	4
5,200		90,100		90,100	5
8,000		179,366		179,366	6
308,043		7,932,716		7,932,716	7
12,623		298,653		298,653	8
5,259		215,680		215,680	9
634		19,789		19,789	10
82,755		1,894,730		1,894,730	11
30,227		600,347		600,347	12
383,332		11,511,209		11,511,209	13
3,273		75,598		75,598	14
0	0	0	0	0	
4,001,034	5,934,659	117,608,755	-377,655	123,165,759	
4,001,034	**5,934,659**	**117,608,755**	**-377,655**	**123,165,759**	

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 2016/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.
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.
		450,000		450,000	1
1,986		49,635		49,635	2
5,734		91,476		91,476	3
20,484		287,680		287,680	4
		127,128		127,128	5
186,877		5,368,168		5,368,168	6
49,636		1,205,944		1,205,944	7
8,021		119,591		119,591	8
		9,159,985		9,159,985	9
662		-544,947		-544,947	10
90		73,860		73,860	11
128,342		3,239,281		3,239,281	12
		-43		-43	13
					14
0	0	0	0	0	
4,001,034	5,934,659	117,608,755	-377,655	123,165,759	
4,001,034	**5,934,659**	**117,608,755**	**-377,655**	**123,165,759**	

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 2016/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.
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.
			667,854	667,854	1
			-598,884	-598,884	2
			36,208	36,208	3
			-10	-10	4
			-616,248	-616,248	5
					6
1,936	5,934,659	2,163		5,936,822	7
					8
					9
					10
					11
					12
					13
					14
0	0	0	0	0	
4,001,034	5,934,659	117,608,755	-377,655	123,165,759	
4,001,034	**5,934,659**	**117,608,755**	**-377,655**	**123,165,759**	

Schedule Page: 310.2 Line No.: 3 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: 310.3 Line No.: 1 Column: j

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

Schedule Page: 310.4 Line No.: 9 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

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

Schedule Page: 310.5 Line No.: 2 Column: j

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

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

Carty test energy reclassed to capital.

Schedule Page: 310.5 Line No.: 7 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 (2) [ ] A Resubmission	/ /	End of 2016/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	2,856,938	2,824,281
5	(501) Fuel	75,916,482	91,855,769
6	(502) Steam Expenses	6,831,410	7,020,787
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses	8,121,397	8,406,229
11	(507) Rents	42,262	40,272
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	93,768,489	110,147,338
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	950,845	1,245,737
16	(511) Maintenance of Structures	1,094,274	1,466,174
17	(512) Maintenance of Boiler Plant	7,497,261	5,747,847
18	(513) Maintenance of Electric Plant	12,383,171	15,367,331
19	(514) Maintenance of Miscellaneous Steam Plant	1,341,286	970,770
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	23,266,837	24,797,859
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	117,035,326	134,945,197
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	865,203	821,428
45	(536) Water for Power	568,105	557,345
46	(537) Hydraulic Expenses	6,908,505	5,975,478
47	(538) Electric Expenses	1,230,715	1,110,068
48	(539) Miscellaneous Hydraulic Power Generation Expenses	3,049,632	2,680,908
49	(540) Rents	672,782	737,026
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	13,294,942	11,882,253
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	796,022	920,238
54	(542) Maintenance of Structures	137,894	316
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,871,508	554,625
56	(544) Maintenance of Electric Plant	1,309,814	1,135,192
57	(545) Maintenance of Miscellaneous Hydraulic Plant	1,253,936	1,102,573
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	5,369,174	3,712,944
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	18,664,116	15,595,197

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 2016/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	3,820,585	3,840,358
63	(547) Fuel	218,907,039	183,374,016
64	(548) Generation Expenses	7,064,413	6,544,502
65	(549) Miscellaneous Other Power Generation Expenses	12,715,658	8,075,822
66	(550) Rents	1,135,286	447,761
67	TOTAL Operation (Enter Total of lines 62 thru 66)	243,642,981	202,282,459
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	725,649	775,598
70	(552) Maintenance of Structures	692,528	469,781
71	(553) Maintenance of Generating and Electric Plant	40,364,586	43,705,537
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	1,017,793	556,621
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	42,800,556	45,507,537
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	286,443,537	247,789,996
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	264,106,264	325,139,822
77	(556) System Control and Load Dispatching	52,886	69,545
78	(557) Other Expenses	19,074,719	17,638,596
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	283,233,869	342,847,963
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	705,376,848	741,178,353
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	4,856,873	5,214,043
84			
85	(561.1) Load Dispatch-Reliability	12,519	14,759
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	587,601	577,320
87	(561.3) Load Dispatch-Transmission Service and Scheduling	1,204,546	1,051,058
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	11,450	29,989
90	(561.6) Transmission Service Studies		739
91	(561.7) Generation Interconnection Studies	173	
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	128,451	149,097
94	(563) Overhead Lines Expenses	24,083	15,293
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	76,819,291	81,338,058
97	(566) Miscellaneous Transmission Expenses	5,994,781	4,873,194
98	(567) Rents	2,603,243	2,458,627
99	TOTAL Operation (Enter Total of lines 83 thru 98)	92,243,011	95,722,177
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	42,953	42,238
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software	771,530	656,180
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,818,551	1,051,562
108	(571) Maintenance of Overhead Lines	488,486	614,453
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	123	5,315
111	TOTAL Maintenance (Total of lines 101 thru 110)	3,121,643	2,369,748
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	95,364,654	98,091,925

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	21,879,494	18,270,237
135	(581) Load Dispatching	1,827,184	1,628,648
136	(582) Station Expenses	1,149,199	925,124
137	(583) Overhead Line Expenses	3,101,422	1,604,180
138	(584) Underground Line Expenses	4,890,482	2,717,292
139	(585) Street Lighting and Signal System Expenses	745,908	691,347
140	(586) Meter Expenses	2,886,772	3,199,250
141	(587) Customer Installations Expenses	3,786,067	2,985,514
142	(588) Miscellaneous Expenses	7,769,194	8,360,066
143	(589) Rents	1,597,954	1,602,504
144	TOTAL Operation (Enter Total of lines 134 thru 143)	49,633,676	41,984,162
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	45,062	63,739
147	(591) Maintenance of Structures	131,768	180,978
148	(592) Maintenance of Station Equipment	4,434,226	4,605,837
149	(593) Maintenance of Overhead Lines	42,841,925	40,218,842
150	(594) Maintenance of Underground Lines	6,891,835	5,881,927
151	(595) Maintenance of Line Transformers	2,034,995	709,378
152	(596) Maintenance of Street Lighting and Signal Systems	1,071,417	1,055,252
153	(597) Maintenance of Meters	80,032	49,201
154	(598) Maintenance of Miscellaneous Distribution Plant	9,446,556	6,668,116
155	TOTAL Maintenance (Total of lines 146 thru 154)	66,977,816	59,433,270
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	116,611,492	101,417,432
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision		
160	(902) Meter Reading Expenses	673,600	752,915
161	(903) Customer Records and Collection Expenses	45,013,372	43,336,811
162	(904) Uncollectible Accounts	5,152,432	5,517,924
163	(905) Miscellaneous Customer Accounts Expenses	5,595,059	5,092,796
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	56,434,463	54,700,446

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 2016/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	12,176,505	12,769,301
169	(909) Informational and Instructional Expenses	2,015,784	2,288,709
170	(910) Miscellaneous Customer Service and Informational Expenses		
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	14,192,289	15,058,010
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	61,816,665	60,379,263
182	(921) Office Supplies and Expenses	20,759,207	18,629,826
183	(Less) (922) Administrative Expenses Transferred-Credit	10,284,696	9,387,410
184	(923) Outside Services Employed	11,902,472	8,455,706
185	(924) Property Insurance	5,444,257	5,163,737
186	(925) Injuries and Damages	4,422,890	5,181,555
187	(926) Employee Pensions and Benefits	57,374,107	61,127,470
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	7,708,208	8,003,274
190	(929) (Less) Duplicate Charges-Cr.	2,254,487	2,244,766
191	(930.1) General Advertising Expenses	538,053	426,149
192	(930.2) Miscellaneous General Expenses	11,461,517	9,170,808
193	(931) Rents	4,875,592	4,148,929
194	TOTAL Operation (Enter Total of lines 181 thru 193)	173,763,785	169,054,541
195	Maintenance		
196	(935) Maintenance of General Plant	2,706,940	2,743,739
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	176,470,725	171,798,280
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	1,164,450,471	1,182,244,446

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 2016/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	ATCO Power	SF	WSPP-1	NA	NA	NA
2	Avangrid Renewables	SF	PGE-11	NA	NA	NA
3	Avangrid Renewables	LU	PGE-11	NA	NA	NA
4	Avangrid Renewables	LU	PGE-11	100	100	100
5	Avista Corp. (was WWP)	SF	WSPP-1	NA	NA	NA
6	Avista Corp. (was Spokane Energy, LLC)	LF	PGE-82	150	150	144
7	Avista Corp. (was Spokane Energy, LLC)	EX	PGE-82	NA	NA	NA
8	Baldock Solar	LU	Baldock	NA	NA	NA
9	Bellevue Solar	LU	Bellevue	NA	NA	NA
10	Bonneville Power Administration	SF	WSPP-1	NA	NA	NA
11	BP Energy Company	SF	PGE-11	NA	NA	NA
12	Burbank, City of	SF	WSPP-1	NA	NA	NA
13	California Independent System Operator	SF	CAISO	NA	NA	NA
14	Calpine Energy Services	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 (2) [ ] A Resubmission	/ /	End of 2016/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 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	Cargill Power Markets, LLC	SF	WSPP-1	NA	NA	NA
2	Chelan County, PUD No. 1, Washington	SF	WSPP-1	NA	NA	NA
3	Citigroup Energy	SF	WSPP-1	NA	NA	NA
4	Clatskanie County PUD	SF	WSPP-1	NA	NA	NA
5	ConocoPhillips	SF	WSPP-1	NA	NA	NA
6	Conduit 3 Hydro	LU	201.00	NA	NA	NA
7	Covanta Marion	LU	QF83-118	NA	NA	NA
8	CP Energy Marketing (US)	SF	WSPP-1	NA	NA	NA
9	Douglas County, PUD No. 1, Washington	LU	Wells	NA	NA	NA
10	Douglas County, PUD No. 1, Washington	LF	Wells	NA	NA	NA
11	Douglas County, PUD No. 1, Washington	SF	WSPP-1	NA	NA	NA
12	EDF Trading North America, LLC	SF	WSPP-1	NA	NA	NA
13	Energy Keepers, Inc. - ENKP	SF	WSPP-1	NA	NA	NA
14	ESI Vansycle Partners, LP	LU	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 (2) [ ] A Resubmission	/ /	End of 2016/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)	Average Monthly CP Demand (f)
1	Eugene Water & Electric Board	LU	WSPP-1	10	10	10
2	Eugene Water & Electric Board	LU	ER94-717	NA	NA	NA
3	Eugene Water & Electric Board	LU	Harriet Lake	NA	NA	NA
4	Eugene Water & Electric Board	SF	WSPP-1	NA	NA	NA
5	Exelon Generation Co.	SF	WSPP-1	NA	NA	NA
6	Forest Glen Oaks Biomass	LU	FGO	NA	NA	NA
7	Gridforce Energy Management	SF	WSPP-1	NA	NA	NA
8	Glendale, City of	SF	WSPP-1	NA	NA	NA
9	Grant County, PUD No. 2, Washington	LU	Wanapum	NA	NA	NA
10	Grant County, PUD No. 2, Washington	LU	Priest Rapids	NA	NA	NA
11	Grant County, PUD No. 2, Washington	SF	WSPP-1	NA	NA	NA
12	Idaho Power Company	SF	WSPP-1	NA	NA	NA
13	JC Biomethane	LF	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	Los Angeles Depart Water Power	SF	WSPP-1	NA	NA	NA
2	Macquarie Cook Power	SF	WSPP-1	NA	NA	NA
3	Modesto Irrigation District	SF	WSPP-1	NA	NA	NA
4	Morgan Stanley Capital Group	SF	PGE-11	NA	NA	NA
5	NaturEner Power Watch, LLC	SF	WSPP-1	NA	NA	NA
6	Nevada Power Company	SF	WSPP-1	NA	NA	NA
7	NextEra Energy Power Marketing, LLC	SF	WSPP-1	NA	NA	NA
8	NextEra Energy Power Marketing, LLC	LF	WSPP-1	NA	NA	NA
9	Northern Wasco PUD Hydro	LU	NWASCO	NA	NA	NA
10	NorthWestern Corporation	SF	WSPP-1	NA	NA	NA
11	Okanogan County PUD, Washington	SF	WSPP-1	NA	NA	NA
12	Outback Solar	LU	Outback	NA	NA	NA
13	PacifiCorp	RQ	PP&L 147	NA	NA	NA
14	PacifiCorp	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 (2) [ ] A Resubmission	/ /	End of 2016/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	PaTu Wind	LU	WSPP-1	NA	NA	NA
2	Portland, City of	LU	#2821	NA	NA	NA
3	Powerex	SF	PGE-11	NA	NA	NA
4	PRC - Coffin Butte Biomass	LU	PRC	NA	NA	NA
5	Public Service Company of Colorado	SF	WSPP-1	NA	NA	NA
6	Public Utility District No. 1 of Clark	SF	WSPP-1	NA	NA	NA
7	Puget Sound Energy	SF	WSPP-1	NA	NA	NA
8	Roseville, City of	SF	WSPP-1	NA	NA	NA
9	Sacramento Municipal Utility District	SF	WSPP-1	NA	NA	NA
10	Seattle City Light	SF	WSPP-1	NA	NA	NA
11	Shell Energy	SF	WSPP-1	NA	NA	NA
12	Snohomish County, PUD No. 1, Washingtn	SF	WSPP-1	NA	NA	NA
13	Southern California Edison	SF	PGE-11	NA	NA	NA
14	Steel Bridge	LU	201	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 (2) [ ] A Resubmission	/ /	End of 2016/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	Tacoma, City of	SF	WSPP-1	NA	NA	NA
2	Talen Energy	SF	PGE-11	NA	NA	NA
3	Tenaska	SF	WSPP-1	NA	NA	NA
4	The Energy Authority	SF	WSPP-1	NA	NA	NA
5	Tillamook Biomass	LU	TBIO	NA	NA	NA
6	TransAlta Energy Marketing	SF	PGE-11	NA	NA	NA
7	TransAlta Energy Marketing	LF	PGE-11	NA	NA	NA
8	TransCanada Energy Marketing	SF	WSPP-1	NA	NA	NA
9	Turlock Irrigation District	SF	WSPP-1	NA	NA	NA
10	Vitol Inc	SF	WSPP-1	NA	NA	NA
11	Warm Springs Power Enterprises	LU	WSPP-1	NA	NA	NA
12	Western Area Power Authority	SF	WSPP-1	NA	NA	NA
13	Yamhill Solar	LU	Yamhill	NA	NA	NA
14	Lake Oswego Corporation	LU	201	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 (2) [ ] A Resubmission	/ /	End of 2016/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	Country Village Estates	OS	201	NA	NA	NA
2	Domaine Drouhin	OS	201	NA	NA	NA
3	Von Land Co	OS	201	NA	NA	NA
4	Minikahada Hydropower Co	OS	201	NA	NA	NA
5	Starbucks Properties	OS	201	NA	NA	NA
6	SunWay LLC	LU	201	NA	NA	NA
7	Solar Payment Option	OS	215-217	NA	NA	NA
8	Tualatin Valley Water Dist	OS	201	NA	NA	NA
9	Oregon Heat	OS	203	NA	NA	NA
10	Load Curtailment Program			NA	NA	NA
11	Margin on Electric Financials			NA	NA	NA
12	Green Power			NA	NA	NA
13	REC Retirement Expense			NA	NA	NA
14	Carbon Allowance Expense			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 (2) [ ] A Resubmission	/ /	End of 2016/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						
2	Non-cash exchanges					
3	Energy Storage Expense					
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

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)	
2,093				53,605		53,605	1
450,478				8,782,784		8,782,784	2
195,402				10,343,879		10,343,879	3
			2,445,000			2,445,000	4
37,444				1,919,518		1,919,518	5
			19,278,000			19,278,000	6
	399,144	402,221					7
2,000							8
1,721				176,724		176,724	9
556,419				8,230,445		8,230,445	10
36,792				578,978		578,978	11
1,219				16,275		16,275	12
80,589				1,756,285		1,756,285	13
271,912				5,381,754		5,381,754	14
9,452,614	399,144	402,221	21,807,000	211,881,030	30,418,234	264,106,264	

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)	
18,200				424,816		424,816	1
118,017				2,360,283		2,360,283	2
187,548				2,347,412		2,347,412	3
3,536				56,575		56,575	4
4,397				156,767		156,767	5
515				34,769		34,769	6
84,303				1,351,953		1,351,953	7
750				16,850		16,850	8
733,396				10,743,672		10,743,672	9
184,280				6,338,868		6,338,868	10
49,957				1,024,302		1,024,302	11
95,350				2,084,454		2,084,454	12
1,669				40,294		40,294	13
76,398				4,846,267		4,846,267	14
9,452,614	399,144	402,221	21,807,000	211,881,030	30,418,234	264,106,264	

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)	
			84,000			84,000	1
1,333							2
				2,430		2,430	3
56,216				1,325,901		1,325,901	4
106,173				1,735,850		1,735,850	5
901				55,842		55,842	6
16				480		480	7
				41		41	8
403,674							9
404,404				16,072,174		16,072,174	10
40				991		991	11
124,921				2,678,403		2,678,403	12
9,180				566,675		566,675	13
60,585				905,111		905,111	14
9,452,614	399,144	402,221	21,807,000	211,881,030	30,418,234	264,106,264	

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)	
825				54,775		54,775	1
96,927				2,018,930		2,018,930	2
30				1,200		1,200	3
49,368				1,155,973		1,155,973	4
1				31		31	5
100				2,207		2,207	6
15,991				248,632		248,632	7
				-289		-289	8
43,385				886,040		886,040	9
16,619				432,655		432,655	10
9,300				151,872		151,872	11
10,944				980,040		980,040	12
6,766				672,699		672,699	13
110,086				2,123,802		2,123,802	14
9,452,614	399,144	402,221	21,807,000	211,881,030	30,418,234	264,106,264	

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)	
29,064				2,134,129		2,134,129	1
91,036				1,730,849		1,730,849	2
122,809				3,190,164		3,190,164	3
48,375				3,192,709		3,192,709	4
321,321				6,776,120		6,776,120	5
14,537				215,253		215,253	6
302,064				4,674,520		4,674,520	7
150				2,955		2,955	8
3,959				139,460		139,460	9
103,665				1,761,430		1,761,430	10
1,873,099				32,812,983		32,812,983	11
63,160				1,000,165		1,000,165	12
80				1,240		1,240	13
2,317				195,941		195,941	14
9,452,614	399,144	402,221	21,807,000	211,881,030	30,418,234	264,106,264	

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)	
65,476				1,408,349		1,408,349	1
35,484				787,214		787,214	2
1,636				28,629		28,629	3
77,821				1,269,245		1,269,245	4
2,672				151,995		151,995	5
159,336				3,463,719		3,463,719	6
657,350				26,836,149		26,836,149	7
9,155				224,795		224,795	8
38,127				483,461		483,461	9
167,396				3,026,123		3,026,123	10
521,478				14,486,266		14,486,266	11
2				96		96	12
1,228				126,053		126,053	13
260				19,815		19,815	14
9,452,614	399,144	402,221	21,807,000	211,881,030	30,418,234	264,106,264	

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 MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
43				1,114		1,114	1
74				4,444		4,444	2
186				10,925		10,925	3
380				22,221		22,221	4
27				2,181		2,181	5
3,330							6
11,513				551,842		551,842	7
143				8,482		8,482	8
1,691					49,386	49,386	9
					790,224	790,224	10
					20,214,552	20,214,552	11
					8,867,377	8,867,377	12
					269,538	269,538	13
					275,792	275,792	14
9,452,614	399,144	402,221	21,807,000	211,881,030	30,418,234	264,106,264	

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
					-48,635	-48,635	2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
9,452,614	399,144	402,221	21,807,000	211,881,030	30,418,234	264,106,264	

Schedule Page: 326 Line No.: 6 Column: b

This contract (previously with Spokane Energy), expired 12/31/16.

Schedule Page: 326.1 Line No.: 10 Column: b

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

Schedule Page: 326.2 Line No.: 2 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.: 7 Column: b

The TransAlta Energy Marketing contract expired on 9/30/16.

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

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

Schedule Page: 326.6 Line No.: 2 Column: b

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

Schedule Page: 326.6 Line No.: 3 Column: b

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

Schedule Page: 326.6 Line No.: 4 Column: b

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

Schedule Page: 326.6 Line No.: 5 Column: b

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

Schedule Page: 326.6 Line No.: 7 Column: b

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

Schedule Page: 326.6 Line No.: 8 Column: b

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

Schedule Page: 326.6 Line No.: 9 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.: 10 Column: l

Power Purchased under Load Curtailment Program.

Schedule Page: 326.6 Line No.: 11 Column: l

Margin on electric financial transactions.

Schedule Page: 326.6 Line No.: 12 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.: 13 Column: l

Expense of annual REC retirement to meet RPS compliance.

Schedule Page: 326.6 Line No.: 14 Column: l

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

Schedule Page: 326.7 Line No.: 3 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.

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	Avista Corp. Washington Water Power	Bonneville Power Administration	Balancing Authority of N Calif	LFP
2	Avista Corp. Washington Water Power	Bonneville Power Administration	CAISO	LFP
3	Avista Corp. Washington Water Power	CAISO	Bonneville Power Administration	NF
4	Avista Corp. Washington Water Power	Balancing Authority of N Calif	Bonneville Power Administration	OS
5	Avista Corp. Washington Water Power	CAISO	Bonneville Power Administration	OS
6	Bonneville Power Administration	Bonneville Power Administration	Portland General Electric	FNO
7	Bonneville Power Administration	Bonneville Power Administration	CAISO	NF
8	Bonneville Power Administration	Bonneville Power Administration	Western Oregon Electric Coop	OLF
9	Bonneville Power Administration	Bonneville Power Administration	Other TVI Pumps	OLF
10	Bonneville Power Administration	Bonneville Power Administration	Canby People's Utility District	OLF
11	Bonneville Power Administration	Bonneville Power Administration	Columbia River PUD	OLF
12	Brookfield Energy Marketing	Bonneville Power Administration	Balancing Authority of N Calif	SFP
13	Brookfield Energy Marketing	Bonneville Power Administration	CAISO	SFP
14	Canadian Wood Products LLC	Bonneville Power Administration	CAISO	NF
15	EDF Trading North America LLC	CAISO	Bonneville Power Administration	NF
16	Exelon Generation Company LLC	Bonneville Power Administration	Balancing Authority of N Calif	LFP
17	Exelon Generation Company LLC	Bonneville Power Administration	CAISO	LFP
18	Exelon Generation Company LLC	Bonneville Power Administration	CAISO	NF
19	Exelon Generation Company LLC	Bonneville Power Administration	Portland General Electric	OS
20	Iberdrola Renewables Inc.	Bonneville Power Administration	Balancing Authority of N Calif	NF
21	Iberdrola Renewables Inc.	Bonneville Power Administration	CAISO	NF
22	Macquarie Energy LLC	Bonneville Power Administration	CAISO	NF
23	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	Balancing Authority of N Calif	LFP
24	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	CAISO	LFP
25	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	Balancing Authority of N Calif	NF
26	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	CAISO	NF
27	Noble Americas Energy Solutions	Bonneville Power Administration	Portland General Electric	OS
28	Noble Americas Energy Solutions	Portland General Electric	Portland General Electric	OS
29	Pacificorp	PacifiCorp	Portland General Electric	OLF
30	Powerex Corp.	Bonneville Power Administration	Balancing Authority of N Calif	LFP
31	Powerex Corp.	Bonneville Power Administration	CAISO	LFP
32	Powerex Corp.	Bonneville Power Administration	Balancing Authority of N Calif	NF
33	Powerex Corp.	Bonneville Power Administration	CAISO	NF
34	Powerex Corp.	CAISO	Bonneville Power Administration	OS
	TOTAL			

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2016/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	PUD No. 1 of Cowlitz County	RESALE to The Energy Authority		LFP
2	PUD No. 1 of Franklin County	RESALE to The Energy Authority		LFP
3	PUD No. 1 of Klickitat County	RESALE to The Energy Authority		LFP
4	PUD No. 1 of Lewis County	RESALE to The Energy Authority		LFP
5	Puget Sound Energy	Balancing Authority of N Calif	Bonneville Power Administration	LFP
6	Puget Sound Energy	Bonneville Power Administration	Bonneville Power Administration	LFP
7	Puget Sound Energy	CAISO	Bonneville Power Administration	LFP
8	Puget Sound Energy	CAISO	Bonneville Power Administration	NF
9	Puget Sound Energy	Bonneville Power Administration	CAISO	NF
10	Rainbow	CAISO	Bonneville Power Administration	NF
11	Seattle City Light Marketing	Bonneville Power Administration	Balancing Authority of N Calif	NF
12	Seattle City Light Marketing	Bonneville Power Administration	CAISO	NF
13	Shell Energy North America (US), L.P.	Bonneville Power Administration	Balancing Authority of N Calif	LFP
14	Shell Energy North America (US), L.P.	Bonneville Power Administration	CAISO	LFP
15	Shell Energy North America (US), L.P.	Bonneville Power Administration	Balancing Authority of N Calif	NF
16	Shell Energy North America (US), L.P.	Bonneville Power Administration	CAISO	NF
17	Shell Energy North America (US), L.P.	CAISO	Bonneville Power Administration	NF
18	Shell Energy North America (US), L.P.	Balancing Authority of N Calif	Bonneville Power Administration	OS
19	Shell Energy North America (US), L.P.	CAISO	Bonneville Power Administration	OS
20	Shell Energy North America (US), L.P.	Bonneville Power Administration	Portland General Electric	OS
21	Shell Energy North America (US), L.P.	Portland General Electric	Portland General Electric	OS
22	Turlock Irrigation District	Bonneville Power Administration	Balancing Authority of N Calif	NF
23	Tenaska	Bonneville Power Administration	CAISO	NF
24	Sacramento Municipal Utility District	Bonneville Power Administration	Balancing Authority of N Calif	NF
25	The Energy Authority	Bonneville Power Administration	Balancing Authority of N Calif	LFP
26	The Energy Authority	Bonneville Power Administration	CAISO	LFP
27	The Energy Authority	Bonneville Power Administration	Balancing Authority of N Calif	NF
28	The Energy Authority	Balancing Authority of N Calif	Bonneville Power Administration	NF
29	The Energy Authority	Bonneville Power Administration	CAISO	NF
30	The Energy Authority	CAISO	Bonneville Power Administration	NF
31	The Energy Authority	Balancing Authority of N Calif	Bonneville Power Administration	OS
32	The Energy Authority	CAISO	Bonneville Power Administration	OS
33	TransAlta Energy Marketing U.S. Inc.	Bonneville Power Administration	CAISO	NF
34	TransAlta Energy Marketing U.S. Inc.	CAISO	Bonneville Power Administration	NF
	TOTAL			

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2016/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	Accrual			AD
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

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.
7	JohnDay	CaptainJack		232	232	1
7	JohnDay	Malin500		600,622	600,622	2
8	Malin500	JohnDay		157	157	3
8	CaptainJack	JohnDay		325	325	4
8	Malin500	JohnDay		455	455	5
7	BPAT.PGE	PGE	182	88,382	86,521	6
8	JohnDay	Malin500		2,675	2,675	7
72	Various Subs	Various Subs		14,181	12,896	8
72	Various Subs	Various Subs		8,481	7,881	9
72	Various Subs	Various Subs		153,445	139,969	10
72	Various Subs	Various Subs		216,015	196,912	11
7	JohnDay	CaptainJack		6,600	6,600	12
7	JohnDay	Malin500		71,107	71,107	13
8	JohnDay	Malin500		968	968	14
8	Malin500	JohnDay		214	214	15
7	JohnDay	CaptainJack		19,336	19,336	16
7	JohnDay	Malin500		58,383	58,383	17
8	JohnDay	Malin500		4,189	4,189	18
8	BPAT.PGE	PGE	394	186,487	195,266	19
8	JohnDay	CaptainJack		411	411	20
8	JohnDay	Malin500		44	44	21
8	JohnDay	Malin500		21,113	21,113	22
7	JohnDay	CaptainJack		68,545	51,577	23
7	JohnDay	Malin500		6,156	5,719	24
8	JohnDay	CaptainJack		7,009	6,437	25
8	JohnDay	Malin500		9,198	7,453	26
8	BPAT.PGE	PGE	2,490	1,409,829	1,367,025	27
8	PGE.INTERNAL	PGE	356	202,040	194,615	28
Exch	JOHNDAY	Various Subs		-2,332	4,229	29
7	JohnDay	CaptainJack		203,524	203,524	30
7	JohnDay	Malin500		1,612,386	1,612,386	31
8	JohnDay	CaptainJack		19,213	19,213	32
8	JohnDay	Malin500		47,880	47,880	33
8	Malin500	JohnDay		96	96	34
			3,510	**6,816,783**	**6,717,582**	

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 2016/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.
7	JohnDay	COB				1
7	JohnDay	COB				2
7	JohnDay	COB				3
7	JohnDay	COB				4
7	CaptainJack	JohnDay		150	150	5
7	KFallsGen	JohnDay		11,525	11,525	6
7	Malin500	JohnDay		5,471	5,471	7
8	Malin500	JohnDay		344	344	8
8	JohnDay	Malin500		17	17	9
8	Malin500	JohnDay		1	1	10
8	JohnDay	CaptainJack		305	305	11
8	JohnDay	Malin500		409	409	12
7	JohnDay	CaptainJack		49,791	49,791	13
7	JohnDay	Malin500		1,373,030	1,373,030	14
8	JohnDay	CaptainJack		5,480	5,480	15
8	JohnDay	Malin500		37,440	37,440	16
8	Malin500	JohnDay		766	766	17
8	CaptainJack	JohnDay		130	130	18
8	Malin500	JohnDay		818	818	19
8	BPAT.PGE	PGE	87	50,145	42,182	20
8	PGE.INTERNAL	PGE	1	814	512	21
8	JohnDay	CaptainJack		4,280	4,280	22
8	JohnDay	Malin500		100	100	23
8	JohnDay	CaptainJack		107	107	24
7	JohnDay	CaptainJack		37,137	37,137	25
7	JohnDay	Malin500		180,392	180,392	26
8	JohnDay	CaptainJack		3,076	3,076	27
8	CaptainJack	JohnDay		300	300	28
8	JohnDay	Malin500		6,718	6,718	29
8	Malin500	JohnDay		1,973	1,973	30
8	CaptainJack	JohnDay		1,120	1,120	31
8	Malin500	JohnDay		3,154	3,154	32
8	JohnDay	Malin500		4,321	4,321	33
8	Malin500	JohnDay		103	103	34
			3,510	**6,816,783**	**6,717,582**	

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 2016/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.
						1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			3,510	**6,816,783**	**6,717,582**	

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.
	270		270	1
	641,369		641,369	2
	201		201	3
				4
				5
108,390			108,390	6
	3,635		3,635	7
	100,076		100,076	8
	28,495		28,495	9
	348,940		348,940	10
	26,036		26,036	11
	28,802		28,802	12
	319,026		319,026	13
	1,375		1,375	14
	273		273	15
	22,156		22,156	16
	43,906		43,906	17
	4,279		4,279	18
249,798			249,798	19
	502		502	20
	54		54	21
	27,996		27,996	22
	58,986		58,986	23
	5,313		5,313	24
	9,209		9,209	25
	11,605		11,605	26
1,622,408			1,622,408	27
233,294			233,294	28
		247,269	247,269	29
	198,924		198,924	30
	1,615,655		1,615,655	31
	27,466		27,466	32
	73,003		73,003	33
				34
2,271,679	**5,591,402**	**117,065**	**7,980,146**	

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.
	64,299		64,299	1
	64,299		64,299	2
	70,729		70,729	3
	70,729		70,729	4
	6,232		6,232	5
	462,076		462,076	6
	174,681		174,681	7
	277		277	8
	22		22	9
	3		3	10
	395		395	11
	463		463	12
	49,043		49,043	13
	1,234,439		1,234,439	14
	6,280		6,280	15
	45,123		45,123	16
	1,217		1,217	17
				18
				19
57,106			57,106	20
683			683	21
	4,417		4,417	22
	127		127	23
	210		210	24
	-53,324		-53,324	25
	-230,205		-230,205	26
	3,829		3,829	27
	343		343	28
	9,748		9,748	29
	2,560		2,560	30
				31
				32
	5,706		5,706	33
	132		132	34
2,271,679	**5,591,402**	**117,065**	**7,980,146**	

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.
		-130,204	-130,204	1
				2
				3
				4
				5
				6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
2,271,679	**5,591,402**	**117,065**	**7,980,146**	

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

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

Schedule Page: 328 Line No.: 2 Column: d

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

Schedule Page: 328 Line No.: 4 Column: d

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

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

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

Schedule Page: 328 Line No.: 8 Column: d

Contract with Bonneville Power Administration continues until terminated.

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

Contract with Bonneville Power Administration continues until terminated.

Schedule Page: 328 Line No.: 10 Column: d

Contract with Bonneville Power Administration continues until terminated.

Schedule Page: 328 Line No.: 11 Column: d

Contract with Bonneville Power Administration continues until terminated.

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

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

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

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

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

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

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

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

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

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

Schedule Page: 328 Line No.: 27 Column: d

Represents non-billed redirected MWHs of Noble Americas Energy Solutions’ service.

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

Represents non-billed redirected MWHs of Noble Americas Energy Solutions’ service.

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

Exchange agreement with PacifiCorp.

Schedule Page: 328 Line No.: 30 Column: d

Contract with Powerex Corp continues until terminated.

Schedule Page: 328 Line No.: 31 Column: d

Contract with Powerex Corp continues until terminated.

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

Represents non-billed redirected MWHs of Powerex Corp’s service.

Schedule Page: 328.1 Line No.: 1 Column: c

Represents the reassignment of Public Utility District No. 1 of Cowlitz County's transmission capacity rights.

Schedule Page: 328.1 Line No.: 1 Column: d

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

Schedule Page: 328.1 Line No.: 2 Column: c

Represents the reassignment of Public Utility District No. 1 of Franklin County's transmission capacity rights.

Schedule Page: 328.1 Line No.: 2 Column: d

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

Schedule Page: 328.1 Line No.: 3 Column: c

Represents the reassignment of Public Utility District No. 1 of Klickitat County's transmission capacity rights.

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

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

Schedule Page: 328.1 Line No.: 4 Column: c

Represents the reassignment of Public Utility District No. 1 of Lewis County's transmission capacity rights.

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

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

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

Contract with Puget Sound Energy expires 01/01/2017.

Schedule Page: 328.1 Line No.: 6 Column: d

Contract with Puget Sound Energy expires 01/01/2017.

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

Contract with Puget Sound Energy expires 01/01/2017.

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

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

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

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

Schedule Page: 328.1 Line No.: 18 Column: d

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

Schedule Page: 328.1 Line No.: 19 Column: d

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

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

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

Schedule Page: 328.1 Line No.: 21 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 The Energy Authority expires 01/01/2034.

Schedule Page: 328.1 Line No.: 26 Column: d

Contract with The Energy Authority expires 01/01/2034.

Schedule Page: 328.1 Line No.: 31 Column: d

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

Schedule Page: 328.1 Line No.: 32 Column: d

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

Schedule Page: 328.2 Line No.: 1 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 (2) [ ] A Resubmission	/ /	End of 2016/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					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	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 (2) [ ] A Resubmission	/ /	End of 2016/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	Bonneville Power Admin	LFP			58,008,231			58,008,231
2	Bonneville Power Admin	OS					18,201,162	18,201,162
3	Bonneville Power Admin	SFP	60,030	60,030		148,646		148,646
4	Bonneville Power Admin	NF	13,201	13,201		52,735		52,735
5	Columbia River PUD	NF	12	12		5,026		5,026
6	Diversified Energy Tran	OS					-1,756,157	-1,756,157
7	EDP Renewables	OS					-575,000	-575,000
8	Eugene Water & Electric	NF	20	20		39,510		39,510
9	Idaho Power Company	NF	3,591	3,591		16,476		16,476
10	McMinnville Water & Lig	NF	818	818		7,408		7,408
11	Montana, State of	OS					1,957,095	1,957,095
12	NorthWestern Energy	NF	51,733	51,733		237,259		237,259
13	PacifiCorp	OS					77,814	77,814
14	PacifiCorp	NF	94	94		54,276		54,276
15	Puget Sound Energy	NF				596		596
16	Sacramento Municipal	NF				-215		-215
	TOTAL		278,130	278,130	58,008,231	906,146	17,904,914	76,819,291

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 2016/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		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Seattle City Light	NF	4,681	4,681		4,743		4,743
2	Shell Energy North Amer	NF				187		187
3	Turlock Irrigation Dist	NF	143,950	143,950		339,499		339,499
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		278,130	278,130	58,008,231	906,146	17,904,914	76,819,291

Schedule Page: 332 Line No.: 1 Column: b

Represents the Bonneville Power Administration PTP contracts.

Schedule Page: 332 Line No.: 2 Column: g

Represents Bonneville Power Administration Ancillary Transmission Services.

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

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

Schedule Page: 332 Line No.: 7 Column: g

Represents a payment made to PGE related to a contract termination option.

Schedule Page: 332 Line No.: 11 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 Line No.: 13 Column: g

Represents PacifiCorp's Linneman Transmission Services.

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 2016/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	2,586,713
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	1,920,932
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	1,808,523
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Involuntary Severance	1,589,637
7	Directors Pension	116,922
8	Directors Fees & Expenses	149,770
9	Directors and Officers Expenses	2,296,320
10	Misc Admin Expenses	176,490
11	Colstrip - PPL Montana	637,242
12	Internal & External Reporting	131,094
13	Misc Admin R&D Expenses	47,874
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	11,461,517

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			44,097,840		44,097,840
2	Steam Production Plant	27,413,500	6,778,309			34,191,809
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	18,319,173	69			18,319,242
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	74,340,756	295,641			74,636,397
7	Transmission Plant	10,018,398	1			10,018,399
8	Distribution Plant	100,893,314	13,149			100,906,463
9	Regional Transmission and Market Operation					
10	General Plant	35,430,429	99			35,430,528
11	Common Plant-Electric					
12	TOTAL	266,415,570	7,087,268	44,097,840		317,600,678

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 (2) [ ] A Resubmission	/ /	End of 2016/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 depr. study)						
16	after approval by						
17	the Oregon Public						
18	Utilities Commission						
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							
49							
50							

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 2016/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		164,266	164,266	
2	Docket No. RM06-16				
3					
4	FERC-NERC Reliability		155,128	155,128	
5	Docket No. RM06-22				
6					
7	FERC-Complaint concerning Portland General		57,880	57,880	
8	Electric obligation to integarte with and				
9	purchase from PaTu Wind Farm				
10	Docket No.15-1237				
11					
12	FERC-Energy Imbalance Markets		28,954	28,954	
13	Docket No. ER15-1919				
14					
15	OPUC-Renewable RFP		97,945	97,945	
16	Docket No. UM1773				
17					
18	OPUC-Complaint of PaTu Wind Farm LLC. agianst		52,843	52,843	
19	Portland General Electric Complany, Pursuant				
20	ORS 756.500 Docket No. UM1566				
21					
22	OPUC matters less than $25,000		211,316	211,316	
23					
24	FERC matters less than $25,000		11,625	11,625	
25					
26	Non Docs matters		196,454	196,454	
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL		976,411	976,411	

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 (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
	928	164,266					1
							2
							3
	928	155,128					4
							5
							6
	928	57,880					7
							8
							9
							10
							11
	928	28,954					12
							13
							14
	928	97,945					15
							16
							17
	928	52,843					18
							19
							20
							21
	928	211,316					22
							23
	928	11,625					24
							25
	928	196,454					26
							27
							28
							29
							30
							31
							32
							33
							34
							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		976,411					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 (2) [ ] A Resubmission	/ /	End of 2016/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		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24	Totals	
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
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 (2) [ ] A Resubmission	/ /	End of 2016/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
5,000		930.2	5,000		2
400,747		930.2	400,747		3
111,289		930.2	111,289		4
544,518		930.2	544,518		5
93,578		930.2	93,578		6
206,360		930.2	206,360		7
	559,440	930.2	559,440		8
					9
					10
					11
					12
					13
					14
					15
					16
					17
					18
					19
					20
					21
					22
					23
1,361,492	559,440		1,920,932		24
					25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
					37
					38

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	28,290,475		
4	Transmission	3,971,288		
5	Regional Market			
6	Distribution	18,836,469		
7	Customer Accounts	23,713,377		
8	Customer Service and Informational	6,862,104		
9	Sales			
10	Administrative and General	36,791,070		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	118,464,783		
12	Maintenance			
13	Production	11,976,013		
14	Transmission	1,237,881		
15	Regional Market			
16	Distribution	25,374,153		
17	Administrative and General	820,625		
18	TOTAL Maintenance (Total of lines 13 thru 17)	39,408,672		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	40,266,488		
21	Transmission (Enter Total of lines 4 and 14)	5,209,169		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	44,210,622		
24	Customer Accounts (Transcribe from line 7)	23,713,377		
25	Customer Service and Informational (Transcribe from line 8)	6,862,104		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	37,611,695		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	157,873,455	18,189,015	176,062,470
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 (2) [ ] A Resubmission	/ /	End of 2016/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)	157,873,455	18,189,015	176,062,470
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	78,356,692	4,006,681	82,363,373
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	78,356,692	4,006,681	82,363,373
72	Plant Removal (By Utility Departments)			
73	Electric Plant	1,145,277	73,669	1,218,946
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	1,145,277	73,669	1,218,946
77	Other Accounts (Specify, provide details in footnote):			
78	Other Income and Deductions	1,490,984	140,716	1,631,700
79	Co-Owner Shares of Generating Facilities	4,910,252	170,421	5,080,673
80	Other	752,314	4,089,831	4,842,145
81	Payroll Allocated	26,670,333	-26,670,333	
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	33,823,883	-22,269,365	11,554,518
96	TOTAL SALARIES AND WAGES	271,199,307		271,199,307

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report *(Mo, Da, Yr)* / /	Year/Period of Report End of 2016/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 (2) [ ] A Resubmission	/ /	End of 2016/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) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	125,988	351,787	977,574	1,756,285
3	Net Sales (Account 447)	8,608,487	9,920,445	10,291,674	38,138,580
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	8,734,475	10,272,232	11,269,248	39,894,865

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 2016/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	49,196	MW	18,632,547	6,783,440	Various	255,841
2	Reactive Supply and Voltage				3,060,354	Various	98,507
3	Regulation and Frequency Response				3,060,354	Various	229,401
4	Energy Imbalance	66,727	MWh	1,062,226	1,811	MWh	53,982
5	Operating Reserve - Spinning				3,060,354	MWh	263,917
6	Operating Reserve - Supplement				3,060,354	MWh	263,917
7	Other						
8	Total (Lines 1 thru 7)	115,923		19,694,773	19,026,667		1,165,565

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

Scheduling, System Control and Dispatch	No. of Units	Amount
MW Day	10,186	336
MW Hour	160,938	6,187
MW Month	183	2,186
MW Year	3,551,962	216,536
Sum of Peak Demand (KW)	3,060,171	30,596
	6,783,440	255,841

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

Reactive Supply and Voltage	No. of Units	Amount
MW Month	183	6,720
Sum of Peak Demand (KW)	3,060,171	91,787
	3,060,354	98,507

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

Regulation and Frequency Response	No. of Units	Amount
MW Month	183	15,231
Sum of Peak Demand (KW)	3,060,171	214,170
	3,060,354	229,401

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	3,060,354	263,917

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

Operating Reserve - Supplement	No. of Units	Amount
MW Month	3,060,354	263,917

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.

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 2016/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: PGE

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	4,516	11	1900	3,159	224	1,677		3,802	215
2	February	4,217	29	1900	2,854	205	1,677		3,802	258
3	March	3,956	8	1900	2,903	196	1,677		3,802	245
4	Total for Quarter 1				8,916	625	5,031		11,406	718
5	April	4,115	19	1900	2,585	252	1,677		3,802	49
6	May	4,329	2	2100	2,278	225	1,677		3,802	
7	June	4,406	7	2000	2,741	246	1,677		3,802	
8	Total for Quarter 2				7,604	723	5,031		11,406	49
9	July	4,614	28	1800	3,214	287	1,805		3,802	134
10	August	4,931	12	1800	3,252	281	1,805		3,802	
11	September	4,254	26	1700	2,697	211	1,805		3,802	
12	Total for Quarter 3				9,163	779	5,415		11,406	134
13	October	4,002	3	1900	2,273	230	1,777		3,802	
14	November	3,967	28	1900	2,727	228	1,777		3,802	
15	December	4,893	8	1800	3,416	231	1,777		3,802	30
16	Total for Quarter 4				8,416	689	5,331		11,406	30
17	Total Year to Date/Year				34,099	2,816	20,808		45,624	931

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 2016/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 (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	292	27	1900			307			
2	February	292	17	1900			307			
3	March	292	11	1400			307			
4	Total for Quarter 1						921			
5	April	298	19	1500			307			
6	May	277	1	2000			307			
7	June	225	30	2400			307			
8	Total for Quarter 2						921			
9	July	290	25	600			307			
10	August	283	13	600			307			
11	September	283	3	700			307			
12	Total for Quarter 3						921			
13	October	285	27	400			307			
14	November	283	8	1600			307			
15	December	284	27	2300			307			
16	Total for Quarter 4						921			
17	Total Year to Date/Year						3,684			

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

Long Term Firm Point-to-Point Reservations: Q1

Reservation #	Customer	MW Granted Jan 2016	MW Granted Feb 2016	MW Granted Mar 2016	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
71915367	Powerex Inc.	97	97	97	01/01/2017
74382640	Portland General Electric Company	100	100	100	07/01/2017
74566698	Portland General Electric Company	100	100	100	01/01/2022
75731986	Puget Sound Energy Marketing	100	100	100	01/01/2017
76073144	Portland General Electric Company	(14)	(14)	(14)	07/01/2017
76412778	Portland General Electric Company	200	200	200	01/01/2017
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
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, 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
81712548	Portland General Electric Company	177	177	177	01/01/2021
80266877	Powerex Inc.	10	10	10	01/01/2034
		1,677	**1,677**	**1,677**	

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 2016	MW Granted Feb 2016	MW Granted Mar 2016
82024015	Portland General Electric Company	3,300		
82018815	Portland General Electric Company	500		
82018797	Portland General Electric Company	2		
82179130	Portland General Electric Company		3,300	
82179038	Portland General Electric Company		500	500
82179035	Portland General Electric Company		2	2
82317172	Portland General Electric Company			3,300
	Total	**3,802**	**3,802**	**3,802**

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 2016	MW Granted May 2016	MW Granted Jun 2016	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
71915367	Powerex Inc.	97	97	97	01/01/2017
74382640	Portland General Electric Company	100	100	100	07/01/2017
74566698	Portland General Electric Company	100	100	100	01/01/2022
75731986	Puget Sound Energy Marketing	100	100	100	01/01/2017
76073144	Portland General Electric Company	(14)	(14)	(14)	07/01/2017
76412778	Portland General Electric Company	200	200	200	01/01/2017
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
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, 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
81712548	Portland General Electric Company	177	177	177	01/01/2021
80266877	Powerex Inc.	10	10	10	01/01/2034
		1,677	**1,677**	**1,677**	

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 2016	MW Granted May 2016	MW Granted Jun 2016
82491464	Portland General Electric Company	3,300		
82179038	Portland General Electric Company	500	500	500
82179035	Portland General Electric Company	2	2	2
82658663	Portland General Electric Company		3,300	
82807236	Portland General Electric Company			3,300
	Total	**3,802**	**3,802**	**3,802**

Schedule Page: 400 Line No.: 8 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.: 12 Column: g

Long Term Firm Point-to-Point Reservations: Q3

Reservation #	Customer	MW Granted Jul 2016	MW Granted Aug 2016	MW Granted Sep 2016	Earliest Termination Date
432190	Portland General Electric Company	200	200	200	01/01/2022
71472976	Shell Energy North America (US) LP	200	200	200	01/01/2022
71915367	Powerex Inc.	97	97	97	01/01/2017
74382640	Portland General Electric Company	100	100	100	07/01/2017
74566698	Portland General Electric Company	100	100	100	01/01/2022
75731986	Puget Sound Energy Marketing	100	100	100	01/01/2017
76073144	Portland General Electric Company	14	14	14	07/01/2017
76412778	Portland General Electric Company	200	200	200	01/01/2017
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
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	01/01/2020
80266877	Powerex Inc.	10	10	10	01/01/2034
81712548	Portland General Electric Company	177	177	177	01/01/2021
		1,805	**1,805**	**1,805**	

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 2016	MW Granted Aug 2016	MW Granted Sep 2016
82491464	Portland General Electric Company	3,300		
82179038	Portland General Electric Company	500	500	500
82179035	Portland General Electric Company	2	2	2
82658663	Portland General Electric Company		3,300	
82807236	Portland General Electric Company			3,300
	Total	**3,802**	**3,802**	**3,802**

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)

Name of Respondent Portland General Electric Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report 2016/Q4

FOOTNOTE DATA

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

Long Term Firm Point-to-Point Reservations: Q4

Reservation #	Customer	MW Granted Oct 2016	MW Granted Nov 2016	MW Granted Dec 2016	Earliest Termination Date
432190	Portland General Electric Company	200	200	200	01/01/2022
71472976	Shell Energy North America (US) LP	200	200	200	01/01/2022
71915367	Powerex Inc.	97	97	97	01/01/2017
74382640	Portland General Electric Company	100	100	100	07/01/2017
74566698	Portland General Electric Company	100	100	100	01/01/2022
75731986	Puget Sound Energy Marketing	100	100	100	01/01/2017
76073144	Portland General Electric Company	(14)	(14)	(14)	07/01/2017
76412778	Portland General Electric Company	200	200	200	01/01/2017
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
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	01/01/2020
80266877	Powerex Inc.	10	10	10	01/01/2034
81712548	Portland General Electric Company	177	177	177	01/01/2021
		1,777	**1,777**	**1,777**	

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 2016	MW Granted Nov 2016	MW Granted Dec 2016
82179035	Portland General Electric Company	2	2	2
82179038	Portland General Electric Company	500	500	500
83784731	Portland General Electric Company	3,300	3,300	3,300
	Total	**3,802**	**3,802**	**3,802**

Schedule Page: 400 Line No.: 16 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: 400.1 Line No.: 4 Column: b

Monthly Peak MW:

The entries represent the "Transmission Providers Monthly Transmission System Peak" as defined in PGE's OATT in Section 1.47, the maximum firm usage of PGE's share of the Colstrip transmission system during the calendar month.

Schedule Page: 400.1 Line No.: 4 Column: g

Long Term Firm Point-to-Point Reservations: Q1

Reservation #	Customer	MW Granted Jan 2016	MW Granted Feb 2016	MW Granted Mar 2016	Earliest Termination Date
76059414	Portland General Electric Company	307	307	307	07/01/2022

Schedule Page: 400.1 Line No.: 8 Column: b

Monthly Peak MW:
The entries represent the "Transmission Providers Monthly Transmission System Peak" as defined in PGE's OATT in Section 1.47, the maximum firm usage of PGE's share of the Colstrip transmission system during the calendar month.

Schedule Page: 400.1 Line No.: 8 Column: g

Long Term Firm Point-to-Point Reservations: Q2

Reservation #	Customer	MW Granted Apr 2016	MW Granted May 2016	MW Granted Jun 2016	Earliest Termination Date
76059414	Portland General Electric Company	307	307	307	07/01/2022

Schedule Page: 400.1 Line No.: 12 Column: b

Monthly Peak MW:
The entries represent the "Transmission Providers Monthly Transmission System Peak" as defined in PGE's OATT in Section 1.47, the maximum firm usage of PGE's share of the Colstrip transmission system during the calendar month.

Schedule Page: 400.1 Line No.: 12 Column: g

Long Term Firm Point-to-Point Reservations: Q3

Reservation #	Customer	MW Granted Jul 2016	MW Granted Aug 2016	MW Granted Sep 2016	Earliest Termination Date
76059414	Portland General Electric Company	307	307	307	07/01/2022

Schedule Page: 400.1 Line No.: 16 Column: b

Monthly Peak MW:
The entries represent the "Transmission Providers Monthly Transmission System Peak" as defined in PGE's OATT in Section 1.47, the maximum firm usage of PGE's share of the Colstrip transmission system during the calendar month.

Schedule Page: 400.1 Line No.: 16 Column: g

Long Term Firm Point-to-Point Reservations: Q4

Reservation #	Customer	MW Granted Oct 2016	MW Granted Nov 2016	MW Granted Dec 2016	Earliest Termination Date
76059414	Portland General Electric Company	307	307	307	07/01/2022

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/Q4

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
(5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:

Line No.	Month (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									

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)
1	SOURCES OF ENERGY	
2	Generation (Excluding Station Use):	
3	Steam	3,492,576
4	Nuclear	
5	Hydro-Conventional	1,628,583
6	Hydro-Pumped Storage	
7	Other	7,722,914
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	12,844,073
10	Purchases	9,452,614
11	Power Exchanges:	
12	Received	399,144
13	Delivered	402,221
14	Net Exchanges (Line 12 minus line 13)	-3,077
15	Transmission For Other (Wheeling)	
16	Received	6,816,783
17	Delivered	6,717,582
18	Net Transmission for Other (Line 16 minus line 17)	99,201
19	Transmission By Others Losses	
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	22,392,811

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	17,248,173
23	Requirements Sales for Resale (See instruction 4, page 311.)	
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	3,999,098
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	26,176
27	Total Energy Losses	1,119,364
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	22,392,811

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2016/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 (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	1,897,973	163,351	3,428	3	18
30	February	1,669,533	184,947	3,017	2	8
31	March	1,752,954	189,155	2,915	8	19
32	April	1,701,270	346,419	2,866	19	18
33	May	1,662,680	260,674	2,914	31	18
34	June	1,755,359	317,815	3,551	6	18
35	July	1,913,275	428,562	3,536	29	18
36	August	2,192,894	579,640	3,726	18	18
37	September	1,936,426	596,788	2,971	26	18
38	October	1,824,214	376,636	2,654	24	19
39	November	1,814,501	331,775	2,972	30	19
40	December	2,172,531	282,304	3,716	14	18
41	TOTAL	22,293,610	4,058,066			

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 1,911,589 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 net wind generation from the two projects to BPA was 1,921,840 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 costs at 12/31/2016:	$924,428,188
Total installed capacity:	450 megawatts
Operations and maintenance expenses for 2016:	$17,873,116

The Tucannon River Wind Farm was placed in service on December 15,2014. Key statistics include the following:

In-service production costs at 12/31/2016:	$482,451,493
Total installed capacity:	267 megawatts
Operations and maintenance expense for 2016	$10,579,684

Schedule Page: 401 Line No.: 27 Column: b

PGE has ownership in a 5MW storage battery (Salem Smart Power Center) with a Plant in service balance of $384,933 as of year-end 2016, 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 2016 to FERC 584.1 - Operation of Energy Storage Equipment $1,115 and FERC 592.2 - Maintenance of Energy Storage Equipment $9,666. Line loss includes 0.3MWh of Energy stored in this battery at year-end 2016.

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 (2) [ ] A Resubmission	/ /	End of 2016/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)	606	0
7	Plant Hours Connected to Load	3952	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	94	0
12	Net Generation, Exclusive of Plant Use - KWh	1732571000	1598318000
13	Cost of Plant: Land and Land Rights	939463	832853
14	Structures and Improvements	153519689	140892331
15	Equipment Costs	576836193	513141368
16	Asset Retirement Costs	50153037	44772273
17	Total Cost	781448382	699638825
18	Cost per KW of Installed Capacity (line 17/5) Including	1216.8302	1210.6573
19	Production Expenses: Oper, Supv, & Engr	2996280	2550186
20	Fuel	47178273	43765722
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	5598882	4911874
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	6547856	5757027
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	490934	417740
30	Maintenance of Structures	371580	326572
31	Maintenance of Boiler (or reactor) Plant	1714393	1549129
32	Maintenance of Electric Plant	12039972	10666280
33	Maintenance of Misc Steam (or Nuclear) Plant	546793	496302
34	Total Production Expenses	77484963	70440832
35	Expenses per Net KWh	0.0447	0.0441

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(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	1128066	8707	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	8625	138800	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	46.958	72.613	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	41.822	131.770	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	2.424	22.603	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	11231.400	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 (2) [ ] A Resubmission	/ /	End of 2016/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			1894258000		
13	Cost of Plant: Land and Land Rights	0			3328862		
14	Structures and Improvements	0			114973069		
15	Equipment Costs	0			340915041		
16	Asset Retirement Costs	0			22935683		
17	Total Cost	0			482152655		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			1549.3337		
19	Production Expenses: Oper, Supv, & Engr	0			306752		
20	Fuel	0			32150760		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			1919536		
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			2364370		
27	Rents	0			42262		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			533105		
30	Maintenance of Structures	0			767702		
31	Maintenance of Boiler (or reactor) Plant	0			5948132		
32	Maintenance of Electric Plant	0			1716891		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			844983		
34	Total Production Expenses	0			46594493		
35	Expenses per Net KWh	0.0000			0.0246		
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 Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2016/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
516			434			268			6
2453			6500			6524			7
0			0			0			8
533			421			270			9
0			0			0			10
48			26			30			11
449204000			2397758000			1454647000			12
24473			24473			0			13
36115681			42170927			11344118			14
205689968			230464757			176490621			15
2941318			231072			113193			16
244771440			272891229			187947932			17
400.6735			564.6415			693.0233			18
319855			641817			969462			19
12038598			49457490			23599861			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
2283240			2594434			384088			25
3092348			1286280			705374			26
174374			22968			75131			27
0			0			0			28
654243			5442			14723			29
443516			57705			49051			30
0			0			0			31
5797672			6405834			4772908			32
459251			82423			5585			33
25263097			60554393			30576183			34
0.0562			0.0253			0.0210			35
Gas	Oil		Gas	Oil		Gas	Oil		36
Mcf's	Barrels		Mcf's	Barrels		Mcf's	Barrels		37
4424216	2118	0	16644978	0	0	10677155	0	0	38
1019000	138690	0	1019000	138690	0	1019000	138690	0	39
1.673	0.000	0.000	2.290	0.000	0.000	1.613	0.000	0.000	40
3.098	43.580	0.000	3.095	0.000	0.000	3.285	0.000	0.000	41
3.039	7.496	0.000	3.036	0.000	0.000	3.223	0.000	0.000	42
0.030	0.000	0.000	0.021	0.000	0.000	0.024	0.000	0.000	43
9858.900	0.000	0.000	7076.300	0.000	0.000	7482.200	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2016/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
225	470	0	6
2180	3666	0	7
0	0	0	8
225	0	0	9
0	0	0	10
0	22	0	11
145929000	1363785000	0	12
0	0	0	13
42320772	91013966	0	14
244200065	500762277	0	15
647461	4556945	0	16
287168298	596333188	0	17
1276.3035	1185.5531	0	18
3460	282417	0	19
5257735	29196308	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
231484	1416327	0	25
750895	150204	0	26
26793	0	0	27
0	0	0	28
0	46413	0	29
8429	659	0	30
0	0	0	31
854640	3703741	0	32
26727	275698	0	33
7160163	35071767	0	34
0.0491	0.0257	0.0000	35

(d)			(e)			(f)			Line No.
Gas	Oil		Gas	Oil					36
Mcf's	Barrels		Mcf's	Barrels					37
1395789	0	0	10024299	0	0	0	0	0	38
1019000	138690	0	1019000	138690	0	0	0	0	39
1.673	0.000	0.000	2.013	0.000	0.000	0.000	0.000	0.000	40
7.173	0.000	0.000	3.499	0.000	0.000	0.000	0.000	0.000	41
7.037	0.000	0.000	3.433	0.000	0.000	0.000	0.000	0.000	42
0.069	0.000	0.000	0.026	0.000	0.000	0.000	0.000	0.000	43
9750.100	0.000	0.000	7492.700	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, 2016, 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 (2) [ ] A Resubmission	/ /	End of 2016/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. 0 Plant Name: (b)	FERC Licensed Project No. 2195 Plant Name: Faraday (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	36.80
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	47
7	Plant Hours Connect to Load	0	8,782
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	50
12	Net Generation, Exclusive of Plant Use - Kwh	0	158,393,000
13	Cost of Plant		
14	Land and Land Rights	0	33,434
15	Structures and Improvements	0	6,648,765
16	Reservoirs, Dams, and Waterways	0	26,342,464
17	Equipment Costs	0	9,549,955
18	Roads, Railroads, and Bridges	0	2,045,088
19	Asset Retirement Costs	0	90
20	TOTAL cost (Total of 14 thru 19)	0	44,619,796
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	1,212.4945
22	Production Expenses		
23	Operation Supervision and Engineering	0	149,275
24	Water for Power	0	64,296
25	Hydraulic Expenses	0	1,044,731
26	Electric Expenses	0	312,990
27	Misc Hydraulic Power Generation Expenses	0	1,144,350
28	Rents	0	115,661
29	Maintenance Supervision and Engineering	0	219,911
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	10,617
32	Maintenance of Electric Plant	0	181,205
33	Maintenance of Misc Hydraulic Plant	0	424,773
34	Total Production Expenses (total 23 thru 33)	0	3,667,809
35	Expenses per net KWh	0.0000	0.0232

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 2016/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)	109.80	73.20
6	Net Peak Demand on Plant-Megawatts (60 minutes)	108	0
7	Plant Hours Connect to Load	7,759	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	10	0
12	Net Generation, Exclusive of Plant Use - Kwh	401,582,000	267,735,000
13	Cost of Plant		
14	Land and Land Rights	3,672,025	2,448,139
15	Structures and Improvements	10,489,765	7,449,065
16	Reservoirs, Dams, and Waterways	15,688,182	10,684,259
17	Equipment Costs	13,282,356	11,785,388
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)	46,374,381	34,534,024
21	Cost per KW of Installed Capacity (line 20 / 5)	422.3532	471.7763
22	Production Expenses		
23	Operation Supervision and Engineering	293,145	186,924
24	Water for Power	161,892	91,090
25	Hydraulic Expenses	3,016,126	2,194,648
26	Electric Expenses	178,905	119,107
27	Misc Hydraulic Power Generation Expenses	444,135	244,568
28	Rents	8,901	3,861
29	Maintenance Supervision and Engineering	48,655	807
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	36,081	36,081
32	Maintenance of Electric Plant	308,052	118,224
33	Maintenance of Misc Hydraulic Plant	135,501	64,107
34	Total Production Expenses (total 23 thru 33)	4,631,393	3,059,417
35	Expenses per net KWh	0.0115	0.0114

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 2016/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 Plant Name: North Fork (d)	FERC Licensed Project No. 2195 Plant Name: River Mill (e)	FERC Licensed Project No. 2195 Plant Name: Oak Grove (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
40.80	20.60	51.00	5
57	26	40	6
8,781	8,784	8,752	7
			8
58	25	44	9
7	4	19	10
0	0	6	11
185,934,000	105,221,000	187,389,000	12
			13
377,100	86,408	9,457	14
9,043,334	6,661,677	12,167,611	15
84,633,287	55,267,980	24,368,150	16
8,865,952	8,559,312	12,594,832	17
2,579,000	421,796	3,664,772	18
6	64	2,122	19
105,498,679	70,997,237	52,806,944	20
2,585.7519	3,446.4678	1,035.4303	21
			22
81,658	58,142	74,152	23
50,520	41,820	62,124	24
590,437	292,534	1,241,185	25
453,142	42,419	89,131	26
489,751	163,203	221,524	27
33,903	0	500,816	28
154,862	156,203	100,991	29
0	1,334	57,560	30
757,362	534,518	177,776	31
71,503	118,463	84,030	32
286,408	42,263	160,616	33
2,969,546	1,450,899	2,769,905	34
0.0160	0.0138	0.0148	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 (2) [ ] A Resubmission	/ /	End of 2016/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 Plant Name: Round Butte (d)	FERC Licensed Project No. 2030 Plant Name: Round Butte (e)	FERC Licensed Project No. 2233 Plant Name: Sullivan (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
313	0	18	6
8,273	0	7,965	7
			8
345	0	18	9
192	0	7	10
36	0	1	11
931,159,000	620,804,000	103,107,000	12
			13
3,726,481	2,521,011	572,077	14
17,519,007	11,671,555	12,868,921	15
168,937,143	110,464,244	26,111,150	16
36,288,525	24,347,644	13,914,065	17
2,486,900	1,683,325	0	18
164	164	2,630	19
228,958,220	150,687,943	53,468,843	20
614.6529	606.8052	3,472.0028	21
			22
415,067	285,241	29,811	23
310,171	223,635	34,620	24
2,460,943	1,456,914	88,056	25
219,787	146,700	67,225	26
886,445	642,529	143,707	27
24,700	18,540	0	28
200,128	141,648	21,601	29
0	0	79,000	30
204,173	204,173	150,981	31
787,572	555,560	180,828	32
340,507	253,248	22,521	33
5,849,493	3,928,188	818,350	34
0.0063	0.0063	0.0079	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.

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 2016/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 (2) [ ] A Resubmission	/ /	End of 2016/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. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			29
			30
			31
			32
			33
			34
			35
			36
			37
			38

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 2016/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	Maclaren	1999	0.50	0.4	3	133,799
2	Oregon Military Dept/A.F.R.C	2001	1.60	1.6	65	186,058
3	US Bank Corp Columbia Center	2001	6.40	6.2	2,622	488,057
4	Portland State University	2004	2.80	2.8	147	261,732
5	Oregon Military Joint Forces HQ	2005	1.60	1.6	40	191,439
6	Stimson Lumber	2005	0.57	0.5	4	159,546
7	FORTIX (ViaWest)	2005	8.50	8.0	1,106	525,984
8	Skyline	2005	2.00	1.8	92	201,526
9	Tri-Quint	2005	0.60	0.5	3	109,968
10	NCCWC- Filter Plant	2005	2.00	1.8	57	122,958
11	PCC Structurals	2005	1.00	0.9	10	113,874
12	Providence Portland Medical Center	2005	6.00	5.4	1,365	265,383
13	Salem Hospital	2006	4.00	3.6	649	188,494
14	Sunrise Water Authority Pump Station	2006	1.25	1.1	25	88,272
15	Providence Newberg Hospital	2006	1.50	1.4	57	156,833
16	Sungard DSG	2006	2.00	1.8	48	331,845
17	Kaiser Sunnyside Hospital	2007	4.50	4.1	1,372	352,752
18	Newberg Waste Water Treatment Plant	2008	2.00	1.8	54	154,458
19	Xerox Corp	2007	4.00	3.6	183	380,259
20	Newberg Water Treatment Plant	2007	1.00	0.9	14	78,159
21	MEMC (Solaicx)	2008	1.00	0.9	5	62,963
22	Solar World	2008	3.00	2.7	98	219,984
23	Oregon Dept of Admin Serv - Data Center	2010	2.00	2.3	123	277,254
24	Sanyo	2010	1.00	0.9	12	43,144
25	Sysco Foods	2010	2.00	1.8	58	184,779
26	Clackamas Intertie 2	2012	0.60	0.5	3	155,832
27	Dawson Creek	2012	0.80	0.7	9	95,706
28	Kaiser Westside Hospital	2012	4.00	3.6	450	408,830
29	North Plains Pump Station	2012	0.80	0.7	12	53,132
30	Oak Lodge Sanitary District	2012	2.00	1.8	55	229,144
31	Oregon Dept of Admin Serv - Revenue Bldg	2012	1.50	1.4	27	284,255
32	Oregon State Hospital	2012	4.00	3.6	421	172,879
33	Portland Service Center	2012	0.50	0.5	5	322,856
34	Sandy Highschool	2012	1.25	1.1	24	179,894
35	TATA Communications - Hillsboro	2012	4.50	3.2	131	328,979
36	Tri-City Wastewater Treatment Plant	2012	2.50	2.3	83	161,695
37	TATA Communications - Portland	2013	6.60	5.4	157	612,983
38	City of Hillsboro Crandall Reservoir	2013	0.80	0.7	10	105,854
39	East County Courts	2013	1.50	1.4	21	316,848
40	City of Portland-Columbia Blvd WWTP	2013	1.00	0.9	17	162,234
41	Food Services of America	2013	2.00	1.8	13	229,875
42						
43						
44						
45						
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 (2) [ ] A Resubmission	/ /	End of 2016/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	9	263,782
2	Carver (Readiness Center) DSG	2014	2.00	1.8	94	818,635
3	Juvenile Justice Center	2014	0.70	0.7	4	171,380
4	Clackamas River Water DSG	2014	2.00	1.8	70	383,436
5	Joint Water Commission	2015	5.00	4.5	345	190,302
6	Wapato Jail	2015	1.50	1.4	19	418,481
7	McLane Foodservice	2016	1.50	1.4		178,372
8	ViaWest Brookwood	2016	9.75	8.8	2,702	159,252
9	Solar	2014	5.35	5.4	3	2,539,576
10	Total					14,223,732
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						

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			64,440	diesel-low s	1,121	1
116,286		7,243	16,679	diesel-low s	1,129	2
70,836		66,466	32,528	diesel-low s	1,200	3
93,476			74,870	diesel-low s	1,221	4
119,650			17,957	diesel-low s	1,121	5
279,905		858	39,355	diesel-low s	929	6
58,443		3,182	83,407	diesel-low s	1,186	7
100,763			22,999	diesel-low s	879	8
183,279		348	9,110	diesel-low s	1,136	9
61,479		3,161	24,475	diesel-low s	1,221	10
113,874		1,480	15,665	diesel-low s	1,393	11
44,231		27,165	26,569	diesel-low s	886	12
47,124		13,102	47,932	diesel-low s	1,214	13
70,617			49,231	diesel-low s	1,121	14
104,555		7,712	34,743	diesel-low s	1,114	15
165,922			9,425	diesel-low s	943	16
78,389			41,501	diesel-low s	1,121	17
77,229		2,198	57,878	diesel-low s	1,314	18
95,065		4,225	19,101	diesel-low s	1,064	19
78,159		2,686	21,514	diesel-low s	1,279	20
62,963			10,857	diesel-low s	1,121	21
73,328		2,348	105,653	diesel-low s	1,079	22
106,636			51,387	diesel-low s	1,121	23
43,144			12,128	diesel-low s	1,121	24
92,390		3,433	9,724	diesel-low s	921	25
259,720		1,098	11,899	diesel-low s	1,293	26
119,632			22,034	diesel-low s	1,121	27
102,207			52,607	diesel-low s	1,121	28
66,415			35,249	diesel-low s	1,121	29
114,572		2,884	36,628	diesel-low s	1,207	30
189,503		1,696	6,101	diesel-low s	850	31
43,220			30,951	diesel-low s	1,121	32
645,711			4,877	diesel-low s	1,121	33
143,915			8,021	diesel-low s	1,350	34
92,410			22,595	diesel-low s	1,121	35
64,678		4,126	7,604	diesel-low s	1,350	36
92,876			80,030	diesel-low s	1,121	37
132,317		2,030	5,864	diesel-low s	1,200	38
211,232			12,957	diesel-low s	1,121	39
162,234		1,728	5,373	diesel-low s	1,250	40
114,938		2,542	32,102	diesel-low s	1,186	41
						42
						43
						44
						45
						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 (2) [ ] A Resubmission	/ /	End of 2016/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			7,939	diesel-low s	1,121	1
409,317			20,148	diesel-low s	1,121	2
228,507			13,544	diesel-low s	1,121	3
191,718		6,456	23,726	diesel-low s	1,243	4
38,060		9,992	1,970	diesel-low s	1,250	5
278,987			11,517	diesel-low s	1,121	6
118,915			7,189	diesel-low s		7
16,334		5,745	23,130	diesel-low s	1,064	8
474,687			110,272	solar		9
		183,884	1,493,455			10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						42
						43
						44
						45
						46

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2016/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 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	611.14	536.65	58

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2016/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	0.84		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	611.14	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 (2) [ ] A Resubmission	/ /	End of 2016/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		6,364,682	6,364,682					9
		3,624,934	3,624,934					10
								11
								12
								13
								14
								15
	1,194,326	43,101,062	44,295,388					16
				1,142,485	320,015	879,035	2,341,535	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	159,853,047	170,405,587	2,359,629	660,942	1,106,555	4,127,126	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 (2) [ ] A Resubmission	/ /	End of 2016/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.
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	68,135,178	76,998,455					21
								22
954KCMACSR								23
795KCMAAC		615,564	615,564					24
								25
				1,217,144	340,927	161,700	1,719,771	26
								27
								28
795KCMACSR		871,841	871,841					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
						65,820	65,820	34
								35
	10,552,540	159,853,047	170,405,587	2,359,629	660,942	1,106,555	4,127,126	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 capactiy conductor on this line. PGE has certain capactiy responsibilities in conjunction with the 500-KV California Oregon Intertie. PGE recorded the CIAC to FERC account 356 Transmission Overhead Conductors and Devices. Wire Milege is not reported here as BPA is owner/operator of this portion of the Transmission Line.

Schedule Page: 422 Line No.: 7 Column: a

On July 29, 2016, the Company placed into service the Carty Generating Station (Carty), a 440 MW baseload natural gas-fired generating plant in Eastern Oregon, located adjacent to the Boardman coal plant. Grassland is a substation built for Carty and Boardman with 500 KV transmission lines connected to both.

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/opertor of these Tranmssion 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 (2) [ ] A Resubmission	/ /	End of 2016/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 From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	CARTY	GRASSLAND	0.75	ST TOWER		1	1
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		0.75			1	1

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage KV (Operating) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
1780	ACSR		500		5,177,590	5,177,591		10,355,181	1
									2
									3
									4
									5
									6
									7
									8
									9
									10
									11
									12
									13
									14
									15
									16
									17
									18
									19
									20
									21
									22
									23
									24
									25
									26
									27
									28
									29
									30
									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
					5,177,590	5,177,591		10,355,181	44

Schedule Page: 424 Line No.: 1 Column: a

On July 29, 2016, the Company placed into service the Carty Generating Station (Carty), a natural gas-fired generating plant in Eastern Oregon, located adjacent to the Boardman coal plant. Grassland is a substation built for Carty and Boardman with 500 KV transmission lines connected to both.

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 2016/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 (2) [ ] A Resubmission	/ /	End of 2016/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	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	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 2016/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. 3, OR	Distrib./unattended	115.00	57.00	12.50
5	Mobile Sub No. 4, OR	Distrib./unattended	115.00	57.00	13.00
6	Molalla, Molalla, OR	Distrib./unattended	57.00	13.00	
7	Mt. Angel, Mt. Angel, OR	Distrib./unattended	57.00	13.00	
8	Mt. Pleasant, Oregon City, OR	Distrib./unattended	115.00	13.00	
9	Multnomah, Portland, OR	Distrib./unattended	115.00	13.00	
10	Newberg, Newberg, OR	Distrib./unattended	115.00	13.00	
11	North Marion, near Woodburn, OR	Distrib./unattended	57.00	13.00	
12	North Plains, North Plains, OR	Distrib./unattended	57.00	13.00	
13	Northern, Portland, OR	Distrib./unattended	57.00	11.00	
14	Oak Hills, near Beaverton, OR	Distrib./unattended	115.00	13.00	
15	Oregon City - BPA, near Wilsonville, OR	Distrib./unattended	57.00		
16	Orenco, near Hillsboro, OR	Distrib./unattended	115.00	57.00	13.00
17	Orenco, near Hillsboro, OR	Distrib./unattended	115.00	13.00	
18	Orient, near Gresham, OR	Distrib./unattended	57.00	13.00	
19	Oswego, Lake Oswego, OR	Distrib./unattended	115.00	13.00	
20	Oxford, Salem, OR	Distrib./unattended	115.00	13.00	
21	Peninsula Park, Portland, OR	Distrib./unattended	115.00	13.00	
22	Pleasant Valley, near Portland, OR	Distrib./unattended	115.00	12.50	
23	Portsmouth, Portland, OR	Distrib./unattended	115.00	13.00	
24	Progress, near Tigard, OR	Distrib./unattended	115.00	13.00	
25	Raleigh Hills, near Portland, OR	Distrib./unattended	115.00	13.00	
26	Ramapo, near Portland, OR	Distrib./unattended	115.00	13.00	
27	Redland, near Oregon City, OR	Distrib./unattended	115.00	13.00	
28	Reedville, near Beaverton, OR	Distrib./unattended	115.00	13.00	
29	Rhododendron Switching, OR	Distrib./unattended	57.00		
30	Rivergate South Yard, near Portland, OR	Distrib./unattended	115.00	13.00	
31	Rivergate South Yard, near Portland, OR	Distrib./unattended	115.00	11.00	
32	Riverview, Portland, OR	Distrib./unattended	115.00	13.00	
33	Rockwood, near Gresham, OR	Distrib./unattended	115.00	13.00	
34	Rosemont, near Lake Oswego, OR	Distrib./unattended	115.00	13.00	
35	Roseway, Hillsboro, OR	Distrib./unattended	115.00	13.00	
36	Ruby,Gresham, OR	Distrib./unattended	115.00	13.00	
37	Salem-PGE, near Salem, OR	Distrib./unattended	57.00	13.00	
38	Sandy, Sandy, OR	Distrib./unattended	57.00	13.00	
39	Scappoose, Scappoose, OR	Distrib./unattended	115.00		
40	Scholls Ferry, Beaverton, OR	Distrib./unattended	115.00	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 (2) [ ] A Resubmission	/ /	End of 2016/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	Scoggin, near Gaston, OR	Distrib./unattended	57.00	13.00	
2	Sellwood, Portland, OR	Distrib./unattended	115.00	57.00	13.00
3	Sellwood, Portland, OR	Distrib./unattended	115.00	13.00	
4	Sheridan, Sheridan, OR	Distrib./unattended	57.00	13.00	
5	Shute, Hillsboro, OR	Distrib./unattended	115.00	34.50	
6	Silverton, Silverton, OR	Distrib./unattended	57.00	13.00	
7	Six Corners, Six Corners, OR	Distrib./unattended	115.00	13.00	
8	Springbrook, Newberg, OR	Distrib./unattended	115.00	13.00	
9	Springdale, near Springdale, OR	Distrib./unattended		12.50	
10	St. Helens, near St. Helens, OR	Distrib./unattended	115.00		
11	St. Johns-BPA, near Portland, OR	Distrib./unattended		11.00	
12	St. Louis, St. Louis, OR	Distrib./unattended	57.00	13.00	
13	St. Marys, East Yard, near Beaverton, OR	Distrib./unattended	115.00	13.00	
14	Stephens, Portland, OR	Distrib./unattended	57.00	11.00	
15	Sullivan, West Linn, OR	Distrib./unattended	115.00	13.00	
16	Summit, Government Camp, OR	Distrib./unattended	57.00	13.00	
17	Summit, Government Camp, OR	Distrib./unattended	24.00	13.00	
18	Sunset, near Hillsboro, OR	Distrib./unattended	115.00	13.00	
19	Sunset, near Hillsboro, OR	Distrib./unattended	115.00	34.50	
20	Swan Island, Portland, OR	Distrib./unattended	115.00	13.00	
21	Sylvan, near Portland, OR	Distrib./unattended	115.00	13.00	
22	Tabor, Portland, OR	Distrib./unattended	115.00	13.00	
23	Tabor, Portland, OR	Distrib./unattended	57.00		
24	Tektronix, Beaverton, OR	Distrib./unattended	115.00	13.00	
25	Tigard, Tigard, OR	Distrib./unattended	115.00	12.50	
26	Town Center, Portland, OR	Distrib./unattended	115.00	13.00	
27	Tualitin, Tualitin, OR	Distrib./unattended	115.00	13.00	
28	Twilight, Canby, OR	Distrib./unattended	57.00	13.00	
29	University, Salem, OR	Distrib./unattended	115.00	13.00	
30	Urban, Portland, OR	Distrib./unattended	115.00	13.00	
31	Waconda, near Hopmere, OR	Distrib./unattended	57.00	12.50	
32	Wallace, Salem, OR	Distrib./unattended	115.00	13.00	
33	Welches, near Welches, OR	Distrib./unattended	57.00	24.00	
34	Welches, near Welches, OR	Distrib./unattended	57.00	13.00	
35	West Portland, Lower Yard, near Tigard, OR	Distrib./unattended	115.00		
36	West Portland, Upper Yard, near Tigard, OR	Distrib./unattended	115.00	13.00	
37	West Union, near Hillsboro, OR	Distrib./unattended	115.00	13.00	
38	Willamina, near Willamina, OR	Distrib./unattended	57.00	13.00	
39	Willbridge, Portland, OR	Distrib./unattended	115.00	11.00	
40	Wilsonville, near Wilsonville, OR	Distrib./unattended	115.00	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 (2) [ ] A Resubmission	/ /	End of 2016/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	Woodburn, Woodburn, OR	Distrib./unattended	57.00	13.00	
2	Yamhill, near Yamhill, OR	Distrib./unattended	57.00	13.00	
3					
4					
5					
6	Bakeoven, BPA, near Bakeoven, OR	Transm./unattended	500.00		
7	Beaver Plant, near Clatskanie, OR	Transm./unattended	230.00	13.00	
8	Beaver Plant, near Clatskanie, OR	Transm./unattended	230.00	24.00	
9	Bethel, Salem, OR	Transm./unattended	230.00	115.00	13.00
10	Bethel, Salem, OR	Transm./unattended	115.00	57.00	13.00
11	Bethel, Salem, OR	Transm./unattended	115.00	13.00	
12	Biglow Canyon Wind Farm, Wasco, OR	Transm./unattended	230.00	34.50	13.80
13	Blue Lake, Troutdale, OR	Transm./unattended	230.00	115.00	13.00
14	Blue Lake, Troutdale, OR	Transm./unattended	115.00	13.00	
15	Boardman, near Boardman, OR	Transm./unattended	500.00	24.00	
16	Boardman, OR	Transm./unattended	230.00	7.20	
17	Boardman, OR	Transm./unattended	24.00	7.20	
18	Broadview Subst. near Broadview, MT	Transm./unattended	500.00	230.00	
19	Buckley, BPA near Buckley, WA	Transm./unattended	500.00		
20	Captain Jack, BPA, near Malin, OR	Transm./unattended	500.00		
21	Carver, Carver, OR	Transm./unattended	230.00	115.00	13.00
22	Carver, Carver, OR	Transm./unattended	115.00	13.00	
23	Colstrip Plant, near Colstrip, MT	Transm./unattended	500.00	26.00	
24	Colstrip Subst. near Colstrip, MT	Transm./unattended	500.00	230.00	
25	Coyote Springs, Boardman, OR	Transm./unattended	500.00		
26	Faraday, Switchyard, near Estacada, OR	Transm./unattended	115.00	57.00	12.50
27	Faraday, Switchyard, near Estacada, OR	Transm./unattended	57.00	11.00	
28	Faraday Plant, near Estacada, OR	Transm./unattended	115.00	12.50	
29	Fort Rock, approx 12 mi NE of Silver Lake, OR	Transm./unattended	500.00		
30	Grassland, near Boardman, OR	Transm./unattended	500.00		
31	Gresham, near Gresham, OR	Transm./unattended	230.00	115.00	13.00
32	Grizzly, BPA, near Madras, OR	Transm./unattended	500.00		
33	Horizon, Hillsboro, OR	Transm./unattended	230.00	115.00	13.00
34	Keeler, BPA, Hillsboro, OR				
35	Linneman, near Gresham, OR	Transm./unattended	230.00	115.00	13.00
36	Malin, BPA, near Malin, OR	Transm./unattended	500.00		
37	McLoughlin, near Oregon City, OR	Transm./unattended	230.00	115.00	13.00
38	Monitor, near Monitor, OR	Transm./unattended	230.00	57.00	13.00
39	Murrayhill, Beaverton, OR	Transm./unattended	230.00	115.00	13.00
40	Murrayhill, Beaverton, OR	Transm./unattended	115.00	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 (2) [ ] A Resubmission	/ /	End of 2016/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	North Fork, near Estacada, OR	Transm./unattended	115.00	13.00	
2	Oak Grove, Three Lynx, OR	Transm./unattended	115.00	13.00	
3	Oak Grove, Three Lynx, OR	Transm./unattended	115.00	11.00	
4	Oak Grove, Three Lynx, OR	Transm./unattended	13.00	11.00	
5	Oak Grove, Three Lynx, OR	Transm./unattended	13.00	0.48	
6	Pearl, BPA, near Wilsonville, OR	Transm./unattended	230.00		
7	Pelton, near Madras, OR	Transm./unattended	230.00	13.00	
8	Pelton, near Madras, OR	Transm./unattended	13.00	13.00	
9	Port Westward, near Clatskanie, OR	Transm./unattended	230.00	18.00	16.50
10	River Mill, near Estacada, OR	Transm./unattended	57.00	11.00	
11	Rivergate North Yard, near Portland, OR	Transm./unattended	230.00	115.00	13.00
12	Round Butte, near Madras, OR	Transm./unattended	500.00	230.00	12.50
13	Round Butte, near Madras, OR	Transm./unattended	230.00	12.50	
14	Sand Springs, 22 mi E/22 mi S of Bend, OR	Transm./unattended	500.00		
15	Sherwood, near Six Corners, OR	Transm./unattended	230.00	115.00	13.00
16	Slatt, BPA, Arlington, OR	Transm./unattended	500.00		
17	St. Marys, West Yard, near Beaverton, OR	Transm./unattended	230.00	115.00	13.00
18	Sullivan, West Linn, OR	Transm./Unattended	57.00	4.15	
19	Sycan, 27 mi S of Silver Lake, OR	Transm./unattended	500.00		
20	Trojan, near Rainier, OR	Transm./unattended	230.00	12.50	
21	Troutdale, BPA near Troutdale OR	Transm./unattended	230.00		
22	Tucannon Mullan Switchyard, Dayton, WA	Transm./unattended	230.00	34.50	13.00
23	TOTAL MVa		30258.00	4956.03	366.80
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
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.
69	9		Capacitor Banks	3	15,600	1
17	1		Capacitor Banks			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) (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.
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	2	7,200	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

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 2016/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.
34	2		Capacitor Banks	1	3,600	1
17	1		Capacitor Banks	2	6,000	2
15	1					3
29	1					4
34	1					5
42	2		Capacitor Banks	4	9,000	6
20	1		Capacitor Banks	3	15,000	7
45	2		Capacitor Banks			8
39	2		Capacitor Banks	3	9,600	9
45	2		Capacitor Banks	4	12,000	10
31	3		Capacitor Banks	3	15,000	11
20	1		Capacitor Banks	4	18,000	12
28	2					13
56	2		Capacitor Banks	4	14,400	14
						15
280	2					16
81	3		Capacitor Banks	6	18,600	17
15	2					18
34	2		Capacitor Banks	2	7,200	19
50	2		Capacitor Banks	4	12,300	20
28	1		Capacitor Banks	2	6,000	21
56	2		Capacitor Banks	4	12,000	22
28	1					23
50	2		Capacitor Banks	4	13,800	24
28	1		Capacitor Banks	2	6,600	25
28	1		Capacitor Banks	2	6,000	26
22	1					27
84	3		Capacitor Banks	6	18,000	28
						29
22	1		Capacitor Banks	2	7,200	30
22	1		Capacitor Banks	2	6,716	31
28	1		Capacitor Banks	2	6,000	32
78	3		Capacitor Banks	5	15,000	33
28	1		Capacitor Banks	2	6,000	34
28	1		Capacitor Banks	2	6,000	35
28	1		Capacitor Banks	2	6,000	36
45	2		Capacitor Banks	4	12,000	37
28	1		Capacitor Banks	2	6,000	38
						39
28	1		Capacitor Banks	2	6,000	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)	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)	
13	2		Capacitor Banks	1	10,800	1
140	1		Capacitor Banks	1	24,000	2
28	1		Capacitor Banks	2	6,000	3
17	1		Capacitor Banks	3	19,200	4
100	2		capacitor Banks	2	9,000	5
33	3		Capacitor Banks	2	3,600	6
49	2		Capacitor Banks	2	6,000	7
56	2		Capacitor Banks	5	36,000	8
						9
			Capacitor Banks	1	24,000	10
						11
24	2		Capacitor Banks	2	7,200	12
56	2		Capacitor Banks	4	12,000	13
100	2		Capacitor Banks	2	16,800	14
45	2		Capacitor Banks	5	36,000	15
8	1	1				16
14	1					17
400	8		Capacitor Banks	25	150,000	18
250	2					19
53	2		Capacitor Banks	4	12,000	20
22	1		Capacitor Banks	2	6,000	21
22	1		Capacitor Banks	2	6,000	22
						23
56	2		Capacitor Banks	4	12,000	24
45	2		Capacitor Banks	4	12,000	25
56	2		Capacitor Banks	2	6,000	26
56	2		Capacitor Banks	4	13,200	27
28	1		Capacitor Banks	3	19,200	28
22	1		Capacitor Banks	2	7,200	29
112	4		Capacitor Banks	6	39,600	30
41	2		Capacitor Banks	2	6,000	31
28	1		Capacitor Banks	2	6,000	32
10	1		Capacitor Banks	1	12,000	33
18	2		Capacitor Banks	2	6,000	34
			Capacitor Banks	1	24,000	35
56	2		Capacitor Banks	4	13,200	36
56	2		Capacitor Banks	4	12,000	37
24	2		Capacitor Banks	3	7,800	38
20	1					39
84	3		Capacitor Banks	6	18,000	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 (2) [ ] A Resubmission	/ /	End of 2016/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.
42	2		Capacitor Banks	4	13,200	1
15	2		Capacitor Banks	1	1,800	2
						3
						4
						5
						6
464	4					7
170	1					8
502	2					9
140	1					10
28	1		Capacitor Banks	2	6,000	11
480	3					12
320	1					13
28	1		Capacitor Banks	2	6,000	14
685	3					15
55	1					16
55	1					17
80	3					18
						19
						20
640	2					21
56	2		Capacitor Banks	4	12,000	22
164	3					23
100	2					24
300	3					25
140	1					26
32	2					27
27	1					28
			Series Capacitor	1	363,000	29
						30
572	2					31
						32
320	1					33
						34
168	1					35
			Reactors	3	180,000	36
640	2					37
125	1					38
320	1					39
56	2		Capacitor Banks	3	10,800	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.
53	3	1				1
8	1					2
64	2					3
						4
						5
						6
164	4					7
3	1					8
450	3					9
32	2					10
520	4		Capacitor Banks	1	22,000	11
561	3		Reactors	12	180,000	12
394	4	2				13
			Series Capacitor	1	546,000	14
640	2					15
						16
960	3		Capacitor Banks	3	108,000	17
33	1					18
			Series Capacitor	1	546,000	19
56	2					20
						21
320	2		Capacitors/Reactors	6	90,000	22
18417	361	4		425	3,593,886	23
						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.: 15 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.: 29 Column: a

Switching only.

Schedule Page: 426.2 Line No.: 39 Column: a

Switching only. Distribution owned by Columbia River PUD.

Schedule Page: 426.3 Line No.: 9 Column: a

Regulating only.

Schedule Page: 426.3 Line No.: 10 Column: a

Switching only. Distribution owned by Columbia River PUD.

Schedule Page: 426.3 Line No.: 11 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.: 23 Column: a

Switching only.

Schedule Page: 426.3 Line No.: 35 Column: a

Switching only.

Schedule Page: 426.4 Line No.: 6 Column: a

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

Schedule Page: 426.4 Line No.: 15 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.: 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 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.: 19 Column: a

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

Schedule Page: 426.4 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.: 23 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.: 24 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.: 25 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.: 29 Column: a

Line compensation only.

Schedule Page: 426.4 Line No.: 30 Column: a

On July 29, 2016, the Company placed into service the Carty Generating Station (Carty), a natural gas-fired generating plant in Eastern Oregon, located adjacent to the Boardman coal plant. Grassland is a substation built for Carty and Boardman with 500 KV transmission lines connected to both.

Schedule Page: 426.4 Line No.: 32 Column: a

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

Schedule Page: 426.4 Line No.: 34 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.: 36 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.: 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: 426.5 Line No.: 7 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.: 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.: 13 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

Line compensation only.

Schedule Page: 426.5 Line No.: 16 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.: 19 Column: a

Line compensation only.

Schedule Page: 426.5 Line No.: 21 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 (2) [ ] A Resubmission	/ /	End of 2016/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	800,961
7				
8	Construction Work in Progress	Sunway 3, LLC	107	2,481,511
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	1,104,898
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Schedule Page: 429 Line No.: 8 Column: d

In January 2016, PGE acquired the assets and liabilities of Sunway 3, LLC, a variable interest entity, at net book value. The entity was subsequently dissolved.

Schedule	Page No.