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

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2016)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2016)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2016)

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** 2014/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/eforms/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/eforms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/eforms.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 2014/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 Kirk M. Stevens	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) 464-7121	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)* 04/16/2015
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 2014/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".

LIST OF SCHEDULES (Electric Utility) (continued)

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

Stockholders' Reports Check appropriate box:

[X] Two copies will be submitted

[ ] No annual report to stockholders is prepared

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.

Kirk M. Stevens
Controller and Assistant Treasurer
121 SW Salmon Street
Portland, OR 97204

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

Oregon - Incorporated July 25, 1930

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

Property of respondent was not so held during the year.

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

The respondent is engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the state of Oregon. The respondent also participates in the wholesale market by purchasing and selling electricity and natural gas in an effort to obtain reasonably-priced power for its 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 2014/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 2014/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 1, LLC	Solar power generation	Dissolved	
15				
16	SunWay 2, LLC	Solar power generation	0.01	
17				
18	SunWay 3, LLC	Solar power generation	0.01	
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Schedule Page: 103 Line No.: 14 Column: c

On January 8, 2014, PGE acquired the assets and liabilities of SunWay 1, LLC, a variable interest entity, at net book value. The entity was subsequently dissolved.

Schedule Page: 103 Line No.: 16 Column: c

SunWay 2, LLC is a variable interest entity jointly owned by PGE (0.01% interest) and U.S. Bank (99.99% interest). Though PGE has only a 0.01% interest, it is the primary beneficiary of the corporation and exercises direct control over the entity and its operations.

Schedule Page: 103 Line No.: 18 Column: c

SunWay 3, LLC is a variable interest entity jointly owned by PGE (0.01% interest) and U.S. Bank (99.99% interest). Though PGE has only a 0.01% interest, it is the primary beneficiary of the corporation and exercises direct control over the entity and its operations.

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 2014/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	733,622
2	Senior Vice President of Finance, Chief Financial	James F. Lobdell	336,507
3	Officer and Treasurer		
4	Senior Vice President of Power Supply & Operations	Maria M. Pope	427,969
5	and Resource Strategy		
6	Senior Vice President, Customer Service,	William O. Nicholson	292,606
7	Transmission and Distribution		
8	Vice President, General Counsel and Corporate	J. Jeffery Dudley	341,133
9	Compliance Officer		
10	Vice President, Nuclear and Power Supply/Generation	Stephen M. Quennoz	299,221
11	Vice President, Human Resources,	Arleen N. Barnett	267,534
12	Diversity and Inclusion, and Administration		
13	Vice President, Customer Strategies and Business	Carol A. Dillin	270,935
14	Development		
15	Vice President, Information Technology and Chief	Campbell A. Henderson	236,357
16	Information Officer		
17	Vice President, Transmission and Distribution	Larry N. Bekkedahl	95,690
18	Vice President, Public Policy	W. David Robertson	267,722
19	Vice President, Customer Service Operations	Kristin A. Stathis	214,186
20	Vice President, Distribution	O. Bruce Carpenter	132,283
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Schedule Page: 104 Line No.: 1 Column: c

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

Schedule Page: 104 Line No.: 17 Column: a

Appointed to position August 25, 2014.

Schedule Page: 104 Line No.: 20 Column: a

Retired from position effective July 7, 2014.

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 2014/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	Phoenix, 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	Coraopolis, Pennsylvania
17	Senior Technology Officer of	
18	RTI International Metals, Inc.	
19	Neil J. Nelson	Portland, Oregon
20	President and Chief Executive Officer of Siltronic Corp.	
21	M. Lee Pelton	Boston, Massachusetts
22	President of Emerson College	
23	James J. Piro	Portland, Oregon
24	President and Chief Executive Officer of	
25	Portland General Electric Company	
26	Charles W. Shivery	Avon, Connecticut
27	Retired Chairman of Northeast Utilities	
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Schedule Page: 105 Line No.: 16 Column: a

Appointed to position April 26, 2014

Schedule Page: 105 Line No.: 26 Column: a

Appointed to position February 20, 2014

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 2014/Q4

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

Does the respondent have formula rates?

[ ] Yes

[X] No

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

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

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

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?	[ ] Yes [X] No

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

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

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

Line No.	Page No(s).	Schedule	Column	Line No
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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. In 1985, PGE sold a 15% undivided interest in the Boardman Plant and a 10.714% undivided interest in the Company's share of the Pacific Northwest Intertie transmission line (jointly, the Facility Assets) to an unrelated third party (Purchaser). Under the terms of the original 1985 agreements, on December 31, 2013, PGE acquired the Facility Assets from the Purchaser in exchange for $1 from the Purchaser. The acquisition of the 15% interest in the Boardman Plant increased the Company's ownership share from 65% to 80% on December 31, 2013.

The acquisition was approved by the Federal Energy Regulatory Commission (FERC) on December 19, 2013 (Docket No. EC14-13-000). The Company recorded the transaction in accordance with the FERC's Uniform System of Accounts.

The original cost of the 15% of the Boardman Plant and the 10.714% undivided interest in the Company's share of the Pacific Northwest Intertie transmission line at December 31, 2013 was estimated at $96 million and $2 million, respectively. It was also estimated that these assets were fully depreciated at the time the acquisition was executed since it coincided with the expiration of various agreements under the terms of the original 1985 transaction.

Proposed final accounting entries were submitted to the FERC on June 27, 2014, which was within six months after the transaction was consummated, as required. Based on subsequent discussions with the Commission Staff, PGE resubmitted proposed journal entries and the accounting entries associated with the asset retirement costs on July 31, 2014 and on September 29, 2014, the FERC approved the accounting entries under Docket No. AC14-129-000. In September 2014, the Company executed the final accounting entries. For further detail on the final accounting entries, see p. 204-207 of this Form 1.

In December 2014, PGE acquired an additional 10% undivided interest from another co-owner in the Boardman Plant, and associated equipment and facilities, as well as certain contracts and other rights related to that co-owner's ownership interest in the Boardman Plant.

The original cost of the 10% of the Boardman Plant and generator tie lines acquired at December 31, 2014 was estimated at $67 million.

On September 19, 2014 PGE filed an application that requested authorization for the acquisition of the rights, titles, and interests associated with this transaction pursuant to section 203(a)(1) of the Federal Power Act (FPA), and included proposed accounting entries. On November 14, 2014, the FERC concluded that the proposed transaction was consistent with public interest and authorized the transaction (Docket EC14-147-000).

In December 2014, the Company executed the accounting entries. For further detail on the final accounting entries, see p. 204-207 of this Form 1.

In accordance with Electric Plant Instruction No. 5 of the Uniform System of Accounts and Electric plant purchased or sold (Account 102), PGE will submit final accounting entries within six months of the date that the proposed transaction was authorized by the FERC.

4. None

5. None

6. Pursuant to PGE's application, the FERC, on February 3, 2014, issued an order in Docket No. ES14-10-000 that authorizes the Company to issue up to $900 million of short-term debt through February 6, 2016. 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.

PGE has the following two unsecured revolving credit facilities as of December 31, 2014, that together provide a total of $700 million in available short-term financing: 1) a $300 million syndicated credit facility, which is scheduled to expire in December 2017; and 2) a $400 million syndicated credit facility, which is scheduled to expire in November 2018. Both revolving credit facilities contain provisions for two one-year extensions that are subject to approval by the banks, require annual fees based on PGE's unsecured credit ratings, and contain customary covenants and default provisions. As of December 31, 2014, PGE had no borrowings or commercial paper outstanding, $20 million of letters of credit issued, and an aggregate available capacity of $680 million under the revolving credit facilities.

In addition, the Company has two, one-year, $30 million letter of credit facilities under which PGE can request letters of credit for original terms not to exceed one year. The issuance of such letters of credit are subject to the approval of the issuing institution. As of December 31, 2014, PGE had issued $56 million of letters of credit under these facilities.

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 credit facilities.

During 2014, PGE obtained four term loans pursuant to a credit agreement in an aggregate principal amount of $305 million. The term loan interest rates are set at the beginning of the interest period for periods ranging from one- to six-months, as selected by PGE and are based on the London Interbank Offered Rate (LIBOR) plus 70 basis points (approximately 0.9% as of December 31, 2014), with no other fees. The credit agreement expires October 30, 2015, 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. Interest is payable monthly on the unsecured term bank loans.

Additionally, in May 2014, PGE entered into a bond purchase agreement with certain institutional buyers (Buyers) under which the Company agreed to sell to the Buyers, in three tranches, an aggregate principal amount of $280 million of First Mortgage Bonds (FMBs). In August 2014, $100 million of 4.39% Series FMBs, due 2045, were issued and funded. In October 2014, $100 million of 4.44% Series FMBs, due 2046, were issued and funded. In November 2014, $80 million of 3.51% Series FMBs, due 2024, were issued and funded.

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, 2014, 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. On May 7, 2014, PGE's shareholders approved an amendment to the Company's Second Amended and Restated Articles of Incorporation to implement majority voting in uncontested elections of directors. Under the new amendment, which adds a new Article X, a nominee for director in an uncontested election will be elected at a shareholder meeting for

the election of directors if the number of votes cast "for" the nominee exceeds the number of votes cast "against" the nominee. For contested elections, the voting standard will continue to be a plurality of votes cast. The new Article X reads in its entirety as follows:

ARTICLE X
Majority Voting in Uncontested Director Elections

> Except as otherwise provided under these Articles of Incorporation and applicable law, in any election of directors of the Corporation at a meeting of shareholders at which a quorum is present, each director shall be elected if the number of votes cast "for" the director exceeds the number of votes cast "against" the director; provided, however, that directors shall be elected by a plurality of the votes cast at any meeting of shareholders for which the Secretary of the Corporation determines that the number of nominees exceeds the number of directors to be elected as of the date seven days prior to the scheduled mailing date of the Corporation's definitive proxy statement for such meeting.

The amendment became effective upon its filing with the Secretary of State of the State of Oregon on May 7, 2014.

In connection with the amendment to the Company's Second Amended and Restated Articles of Incorporation described above, the Board of Directors also approved a conforming amendment to Section 2.9 of the Company's Ninth Amended and Restated Bylaws, which became effective on May 7, 2014. Section 2.9, as amended, reads in its entirety as follows:

> 2.9 Voting Requirements. If a quorum exists, action on a matter, other than the election of directors, is approved if the votes cast by the shares entitled to vote favoring the action exceed the votes cast opposing the action, unless a greater number of affirmative votes is required by law or the Articles of Incorporation. Except as otherwise provided under the Articles of Incorporation and applicable law, in any election of directors at a shareholders' meeting at which a quorum is present, each director shall be elected if the number of votes cast "for" the director exceeds the number of votes cast "against" the director; provided, however, that directors shall be elected by a plurality of the votes cast at any shareholders' meeting for which the Secretary determines that the number of nominees exceeds the number of directors to be elected as of the date seven days prior to the scheduled mailing date of the proxy statement for such meeting. Except as provided in the Act, or unless the Articles of Incorporation provide otherwise, each outstanding share is entitled to one vote on each matter voted on at a shareholders' meeting. Unless otherwise provided in the Articles of Incorporation, cumulative voting for the election of directors shall be prohibited.

8. None

9. Legal Proceedings:

Citizens' Utility Board of Oregon v. Public Utility Commission of Oregon and Utility Reform Project and Colleen O'Neill v. Public Utility Commission of Oregon, Public Utility Commission of Oregon, Marion County Oregon Circuit Court, the Court of Appeals of the State of Oregon, and the Oregon Supreme Court.

PGE, in its 1993 general rate filing, sought OPUC approval to recover through rates future decommissioning costs and full recovery of, and a rate of return on, its Trojan investment. PGE's request was challenged, but in August 1993, the OPUC issued a Declaratory Ruling in PGE's favor. The Citizens' Utility Board (CUB) appealed the decision to the Oregon Court of Appeals.

In PGE's 1995 general rate case, the OPUC issued an order (1995 Order) granting PGE full recovery of Trojan decommissioning costs and 87% of its remaining undepreciated investment in the plant. The Utility Reform Project (URP) filed an appeal of the 1995 Order to the Marion County Circuit Court. The CUB also filed an appeal to the Marion County Circuit Court challenging the portion of the 1995 Order that authorized PGE to recover a return on its remaining undepreciated investment in Trojan.

In April 1996, the Marion County Circuit Court issued a decision that found that the OPUC could not authorize PGE to collect a return on its undepreciated investment in Trojan. The 1996 decision was appealed to the Oregon Court of Appeals.

In June 1998, the Oregon Court of Appeals ruled that the OPUC did not have the authority to allow PGE to recover a rate of return on its undepreciated investment in Trojan. The court remanded the matter to the OPUC for reconsideration of its 1995 Order in light of the court's decision.

In September 2000, PGE, CUB, and the OPUC Staff settled proceedings related to PGE's recovery of its investment in the Trojan plant (Settlement). The URP did not participate in the Settlement and filed a complaint with the OPUC, challenging PGE's application for approval of the accounting and ratemaking elements of the Settlement.

In March 2002, the OPUC issued an order (Settlement Order) denying all of the URP's challenges and approving PGE's application for the accounting and ratemaking elements of the Settlement. The URP appealed the Settlement Order to the Marion County Circuit Court. Following various appeals and proceedings, the Oregon Court of Appeals issued an opinion in October 2007 that reversed the Settlement Order and remanded the Settlement Order to the OPUC for reconsideration.

As a result of its reconsideration of the Settlement Order, the OPUC issued an order in September 2008 that required PGE to refund $33.1 million to customers. The Company completed the distribution of the refund to customers, plus accrued interest, as required.

In October 2008, the URP and the Class Action Plaintiffs (described in the Dreyer proceeding below) separately appealed the September 2008 OPUC order to the Oregon Court of Appeals. On February 6, 2013, the Oregon Court of Appeals issued an opinion that upheld the September 2008 OPUC order.

On October 18, 2013, the Oregon Supreme Court accepted plaintiffs' petition seeking review of the February 6, 2013 Oregon Court of Appeals decision.

On October 2, 2014, the Oregon Supreme Court, in a unanimous decision, affirmed the February 6, 2013 Oregon Court of Appeals decision that upheld the OPUC order dated September 30, 2008. On January 15, 2015, the Oregon Supreme Court denied the plaintiffs petition seeking reconsideration of the October 2, 2014 decision.

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 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 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 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 Marion County Circuit Court in the proceeding described above.

In October 2006, the Marion County Circuit Court issued an Order of Abatement in response to the ruling of the Oregon Supreme Court, abating the class actions for one year.

In October 2007, the Class Action Plaintiffs filed a Motion with the Marion County Circuit Court to lift the abatement. In February 2009, the Circuit Court judge denied the Motion to lift the abatement.

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 have filed petitions for appeal of these procedural orders with the Ninth Circuit.

Pursuant to a FERC-ordered settlement process, the Company received notice of two claims for refunds in the first phase of the remand proceeding and reached agreements to settle both claims for an immaterial amount. The FERC approved both settlements during 2012.

Additionally, the settlement between PGE and certain other parties in the California refund case in Docket No. EL00-95, et seq., approved by the FERC in May 2007, resolved all claims between PGE and the California parties named in the settlement as to transactions in the Pacific Northwest during the settlement period, January 1, 2000 through June 20, 2001, but did not settle potential claims from other market participants relating to transactions in the Pacific Northwest.

The above-referenced settlements resulted in a release of the Company as a named respondent in the first phase of the remand proceedings, which are limited to initial and direct claims for refunds, but there remains a possibility that additional claims related to this matter could be asserted against the Company in a subsequent phase of the proceeding if refunds are ordered against some or all of the current respondents.

During the first phase of the remand hearing, now completed, two sets of refund proponents, the City of Seattle, Washington (Seattle) and various California parties on behalf of the California Energy Resource Scheduling division of the California Department of Water Resources (CERS), presented cases alleging that multiple respondents had engaged in unlawful activities and caused severe financial harm that justified the imposition of refunds. After conclusion of the hearing, the presiding Administrative Law Judge issued an Initial Decision on March 28, 2014 finding: i) that Seattle did not carry its *Mobile-Sierra* burden with respect to its refund claims against any of its respondent sellers; and ii) that the California representatives of CERS did not carry their *Mobile-Sierra* burden with respect to one of the two CERS' respondents, but that CERS had produced evidence that the remaining CERS respondent had engaged in unlawful activity in the implementation of multiple transactions and bad faith in the formation of as many as 119 contracts. The Administrative Law Judge scheduled a second phase of the hearing to commence after a final FERC decision on the Initial Decision. The Administrative Law Judge determined that in the second phase the remaining respondent will have an opportunity to produce additional evidence as to why its transactions should be considered legitimate and why refunds should not be ordered. The findings in the Initial Decision are subject to further FERC action. If the FERC requires one or more respondents to make refunds, it is possible that such respondent(s) will attempt to recover similar refunds from their suppliers, including the Company.

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.

On July 30, 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 PPL 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.

On March 6, 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 are seeking relief that includes civil penalties and 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. In addition, plaintiffs are seeking civil penalties against the co-owners including $32,500 per day for each violation occurring through January 12, 2009, and $37,500 per day for each violation occurring thereafter.

On May 3, 2013, the defendants filed a motion to dismiss 36 of the 39 claims in the complaint. In September 2013, the plaintiffs filed a motion for partial summary judgment regarding the appropriate method of calculating emissions increases. Also in September 2013, the plaintiffs filed an amended complaint that withdrew Title V and opacity claims, added claims associated with two 2011 projects, and expanded the scope of certain claims to encompass approximately 40 additional projects.

In July 2014, the court denied defendants’ motion to dismiss and the plaintiffs’ motion for partial summary judgment. On August 27, 2014, the plaintiffs filed a second amended complaint. The defendants’ response to the second amended complaint was filed on September 26, 2014. The second amended complaint continues to seek injunctive relief, declaratory relief, and civil penalties for alleged violations of the federal Clean Air Act. The plaintiffs state in the second amended complaint that it was filed, in part, to comply with the court’s ruling on the defendants’ motion to dismiss and plaintiffs’ motion for partial summary judgment. Discovery in this matter is ongoing with trial now scheduled for November 2015.

10. None

11. (Reserved)

12. None

13. Changes in Officers and Directors:

On February 19, 2014, the Board of Directors of Portland General Electric Company appointed Charles W. Shivery and Kathryn J. Jackson as directors of the Company to serve until the next annual meeting of shareholders, which was held on May 7, 2014. Mr. Shivery’s appointment was effective February 20, 2014 and Ms. Jackson’s appointment was effective April 26, 2014. The Board of Directors also appointed Mr. Shivery to serve on the Audit Committee and the Finance Committee and appointed Ms. Jackson to serve on the Finance Committee and the Compensation and Human Resources Committee. At the annual meeting of shareholders on May 7, 2014, Mr. Shivery and Ms. Jackson were elected to the Board.

O. Bruce Carpenter, Vice-president of Distribution, retired after 35 years of service with PGE. His last day of employment was July 6, 2014.

On August 25, 2014, Larry Bekkedahl joined PGE as Vice-president of Transmission and Distribution.

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 2014/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	8,301,464,412	7,090,483,780
3	Construction Work in Progress (107)	200-201	417,028,226	507,603,106
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		8,718,492,638	7,598,086,886
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	3,847,673,122	3,469,615,339
6	Net Utility Plant (Enter Total of line 4 less 5)		4,870,819,516	4,128,471,547
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)		4,870,819,516	4,128,471,547
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		32,701,374	29,584,446
19	(Less) Accum. Prov. for Depr. and Amort. (122)		13,489,880	12,642,675
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	3,885,975	4,060,819
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		0	0
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		126,574,714	117,942,828
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		593,801	1,542,540
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		150,265,984	140,487,958
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		6,429,345	2,126,637
36	Special Deposits (132-134)		11,090,727	8,977,158
37	Working Fund (135)		23,061	23,067
38	Temporary Cash Investments (136)		120,000,000	104,000,000
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		130,571,577	136,264,476
41	Other Accounts Receivable (143)		24,041,075	15,388,642
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		6,408,988	5,865,261
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		462,288	590,693
45	Fuel Stock (151)	227	39,025,434	24,019,002
46	Fuel Stock Expenses Undistributed (152)	227	3,333,157	1,402,813
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	35,969,661	34,783,468
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	820,002	478,608

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	3,164,304	4,765,622
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)		41,695,558	41,592,784
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)		93,387,801	103,522,377
62	Miscellaneous Current and Accrued Assets (174)		23,409,706	0
63	Derivative Instrument Assets (175)		7,326,888	14,322,488
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		593,801	1,542,540
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)		533,747,795	484,850,034
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		11,761,685	10,862,206
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	614,275,595	516,243,189
73	Prelim. Survey and Investigation Charges (Electric) (183)		211,533	1,441,335
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)		229,131	140,232
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	11,776,807	16,551,169
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)		15,194,431	16,779,494
82	Accumulated Deferred Income Taxes (190)	234	324,142,876	305,006,638
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		977,592,058	867,024,263
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		6,532,425,353	5,620,833,802

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 2014/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	911,154,338	905,787,872
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	17,842,676	16,366,513
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	10,832,643	10,832,643
11	Retained Earnings (215, 215.1, 216)	118-119	1,000,106,458	912,391,179
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	183,976	102,547
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)	-7,704,212	-5,062,788
16	Total Proprietary Capital (lines 2 through 15)		1,910,750,593	1,818,752,680
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	2,196,400,000	1,916,400,000
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	305,089,838	95,828
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		713,235	770,596
24	Total Long-Term Debt (lines 18 through 23)		2,500,776,603	1,915,725,232
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		9,329,914	8,484,264
29	Accumulated Provision for Pensions and Benefits (228.3)		349,067,148	261,246,787
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		9,531,276	9,905,441
32	Long-Term Portion of Derivative Instrument Liabilities		122,092,454	141,371,181
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		115,704,479	99,533,202
35	Total Other Noncurrent Liabilities (lines 26 through 34)		605,725,271	520,540,875
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		239,924,949	254,713,428
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		509,839	490,937
41	Customer Deposits (235)		14,702,206	14,655,022
42	Taxes Accrued (236)	262-263	10,295,412	9,239,822
43	Interest Accrued (237)		26,383,635	23,164,992
44	Dividends Declared (238)		22,888,174	22,378,496
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2014/Q4

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)		11,728,645	11,467,270
48	Miscellaneous Current and Accrued Liabilities (242)		33,877,206	8,451,916
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		228,023,469	190,600,317
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		122,092,454	141,371,181
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)		466,241,081	393,791,019
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	5,174,407	11,009,032
60	Other Regulatory Liabilities (254)	278	127,549,631	111,443,593
61	Unamortized Gain on Reaquired Debt (257)		66,429	74,481
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		650,919,959	619,065,292
64	Accum. Deferred Income Taxes-Other (283)		265,221,379	230,431,598
65	Total Deferred Credits (lines 56 through 64)		1,048,931,805	972,023,996
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		6,532,425,353	5,620,833,802

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 2014/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	1,926,578,668	1,845,416,891		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,091,797,485	1,119,861,086		
5	Maintenance Expenses (402)	320-323	130,451,217	112,564,149		
6	Depreciation Expense (403)	336-337	241,730,943	228,686,066		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	3,569,396	3,771,528		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	25,400,209	22,054,865		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		3,500,000	3,500,000		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		25,217,405	5,620,441		
13	(Less) Regulatory Credits (407.4)		1,982,810	17,923,138		
14	Taxes Other Than Income Taxes (408.1)	262-263	106,846,515	102,358,656		
15	Income Taxes - Federal (409.1)	262-263	20,555,463	27,599,530		
16	- Other (409.1)	262-263	2,118,584	4,306,119		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	257,916,974	234,017,928		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	217,223,960	225,398,603		
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)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		2,087,165	2,291,604		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,691,984,586	1,623,310,231		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		234,594,082	222,106,660		

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 2014/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

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

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		Line No.
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	
						1
1,926,578,668	1,845,416,891					2
						3
1,091,797,485	1,119,861,086					4
130,451,217	112,564,149					5
241,730,943	228,686,066					6
3,569,396	3,771,528					7
25,400,209	22,054,865					8
						9
3,500,000	3,500,000					10
						11
25,217,405	5,620,441					12
1,982,810	17,923,138					13
106,846,515	102,358,656					14
20,555,463	27,599,530					15
2,118,584	4,306,119					16
257,916,974	234,017,928					17
217,223,960	225,398,603					18
						19
						20
						21
						22
						23
2,087,165	2,291,604					24
1,691,984,586	1,623,310,231					25
234,594,082	222,106,660					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 2014/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)		234,594,082	222,106,660		
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)			34,818		
33	Revenues From Nonutility Operations (417)		6,912,989	3,305,302		
34	(Less) Expenses of Nonutility Operations (417.1)		5,996,233	2,399,247		
35	Nonoperating Rental Income (418)		2,775,814	2,059,541		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	283,851	588,148		
37	Interest and Dividend Income (419)		461,993	125,871		
38	Allowance for Other Funds Used During Construction (419.1)		36,579,261	12,755,088		
39	Miscellaneous Nonoperating Income (421)		-203,932	6,701,374		
40	Gain on Disposition of Property (421.1)		293,563	66,775		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		41,107,306	23,168,034		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		1,807,066	1,648,042		
46	Life Insurance (426.2)		-137,891	-2,810,998		
47	Penalties (426.3)		462,650	91,587		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		851,625	800,736		
49	Other Deductions (426.5)		2,220,161	58,500,515		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		5,203,611	58,229,882		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	1,317,874	1,236,915		
53	Income Taxes-Federal (409.2)	262-263	-527,274	-18,019,089		
54	Income Taxes-Other (409.2)	262-263	-125,648	-4,277,692		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	1,731,121	3,635,375		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	3,368,697	940,796		
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)		-972,624	-18,365,287		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		36,876,319	-16,696,561		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		111,306,270	96,939,583		
63	Amort. of Debt Disc. and Expense (428)		1,007,332	1,076,551		
64	Amortization of Loss on Reaquired Debt (428.1)		1,585,063	5,178,592		
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)		4,618,754	4,523,785		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		22,440,859	6,891,655		
70	Net Interest Charges (Total of lines 62 thru 69)		96,068,508	100,818,804		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		175,401,893	104,591,295		
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)		175,401,893	104,591,295		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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		908,538,384	889,339,341
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)		175,118,042	104,003,147
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			-87,605,185	(85,154,104)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-87,605,185	(85,154,104)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		202,422	350,000
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		996,253,663	908,538,384
	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)		1,000,106,458	912,391,179
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		102,547	(135,601)
50	Equity in Earnings for Year (Credit) (Account 418.1)		283,851	588,148
51	(Less) Dividends Received (Debit)		275,000	350,000
52	Transfer in Due to Dissolution of Subsidiary		72,578	
53	Balance-End of Year (Total lines 49 thru 52)		183,976	102,547

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 2014/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)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	175,401,893	104,591,295
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	270,700,548	254,512,459
5	Amortization of Debt Discount	2,584,343	6,247,091
6	Amortization of Unrecovered Plant	3,500,000	3,500,000
7	Price Risk Management	44,418,752	-17,358,283
8	Deferred Income Taxes (Net)	39,055,438	11,313,904
9	Investment Tax Credit Adjustment (Net)		
10	Net (Increase) Decrease in Receivables	7,847,174	-817,405
11	Net (Increase) Decrease in Inventory	-13,173,045	12,451,434
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-12,540,667	4,613,174
14	Net (Increase) Decrease in Other Regulatory Assets	-12,340,869	27,222,148
15	Net Increase (Decrease) in Other Regulatory Liabilities	31,874,688	-6,402,569
16	(Less) Allowance for Other Funds Used During Construction	36,579,261	12,755,088
17	(Less) Undistributed Earnings from Subsidiary Companies	283,851	588,148
18	Other: Proceeds Received from Trojan Spent Fuel Legal Settlement	5,852,567	44,254,757
19	Other: Write Off Casade Crossing Transmission Project		51,919,581
20	Other: Margin and Customer Deposits	-2,066,385	37,455,224
21	Other Operating	14,090,243	22,853,133
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	518,341,568	543,012,707
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-1,004,912,636	-653,185,696
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-3,135,770	-2,422,590
30	(Less) Allowance for Other Funds Used During Construction	-36,579,261	-12,755,088
31	Other (provide details in footnote):		
32	Other Capital Expenditures	-22,248,332	-4,471,466
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-993,717,477	-647,324,664
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38	Sale of Utility Property	5,453,825	481,156
39	Investments in and Advances to Assoc. and Subsidiary Companies	174,844	-688,148
40	Contributions and Advances from Assoc. and Subsidiary Companies		350,000
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

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 2014/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 Investment	1,607,669	575,099
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	Purchase of Trojan Decommissioning Trust Securities	-18,895,792	-26,357,249
54	Sale of Trojan Decommissioning Trust	16,756,552	25,129,569
55	Contribution to Trojan Decommissioning Trust	-5,852,567	-44,151,519
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-994,472,946	-691,985,756
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	585,000,000	380,000,000
62	Preferred Stock		
63	Common Stock		66,711,004
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		35,000,000
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	585,000,000	481,711,004
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-5,990	-100,005,989
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Debt Issuance Costs	-1,816,907	-2,634,980
78	Net Decrease in Short-Term Debt (c)		-16,999,434
79	Payments on Revolving Line of Credit		-35,000,000
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-86,743,023	-83,551,704
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	496,434,080	243,518,897
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	20,302,702	94,545,848
87			
88	Cash and Cash Equivalents at Beginning of Period	106,149,704	11,603,856
89			
90	Cash and Cash Equivalents at End of period	126,452,406	106,149,704

Schedule Page: 120 Line No.: 18 Column: b

During 2014, PGE received a $6 million legal settlement from the US Department of Energy for the reimbursement of certain costs incurred related to spent nuclear fuel at the Company's Trojan Nuclear power plant between 2010 and 2012. This amount is offset by the contribution to Nuclear Decommissioning Trust Securities on Line 55. The settlement proceeds were deposited into the Nuclear Decommissioning Trust. The proceeds received related to this legal matter will flow to the benefit of customers in future regulatory proceedings to offset amounts previously collected from customers in relation to Trojan decommissioning activities.

Schedule Page: 120 Line No.: 18 Column: c

During 2013, PGE received a $44 million legal settlement from the US Department of Energy for the reimbursement of certain costs incurred related to spent nuclear fuel at the Company's Trojan Nuclear power plant through 2009. This amount is offset by the contribution to Nuclear Decommissioning Trust Securities on Line 55. The settlement proceeds were deposited into the Nuclear Decommissioning Trust. The proceeds received related to this legal matter will flow to the benefit of customers in future regulatory proceedings to offset amounts previously collected from customers in relation to Trojan decommissioning activities.

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

The Cascade Crossing Transmission Project (Cascade Crossing) was originally proposed as a 215-mile, 500kV transmission project between Boardman, Oregon and Salem, Oregon. Based on subsequent analysis and an updated forecast of demand and future transmission capacity in the region, PGE determined in the second quarter of 2013 that the original projections of transmission capacity limitations contemplated in the Integrated Resource Plan (IRP) process were not likely to fully materialize. As a result, PGE and Bonneville Power Administration (BPA) worked toward refining the scope of the project and executed a non-binding memorandum of understanding (MOU) in May 2013. As a result of changed conditions reflected in the May MOU with BPA, PGE suspended permitting and development of Cascade Crossing and charged $52 million of capital costs to Other Deductions (426.5) in the second quarter of 2013. For further information, see "Utility Plant, Net" within Note 2: Balance Sheet Components, contained on p. 123 herein.

Schedule Page: 120 Line No.: 26 Column: b

Net of $23 million accrued sales tax refund related to Tucannon River Wind Farm.

Schedule Page: 120 Line No.: 38 Column: b

The amount of $5 million represents proceeds of $4.1 million from Sale of the Hawthorne building, $0.5 million for sale of Dana Substation and $0.4 million for sale of Lone Fir property.

Schedule Page: 120 Line No.: 38 Column: c

The amount represents recorded costs associated with the sale of the following properties: $246K for the Hawthorne Building, $194K for the Merrit Building and land near the Portland Service Center, $36K for property at the Alder Substation, and $5K miscellaneous.

Schedule Page: 120 Line No.: 55 Column: b

See footnote on Line No.18, column b.

Schedule Page: 120 Line No.: 55 Column: c

See footnote on Line No.18, column C.

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 the Statement of Cash Flows with the related amounts on the Comparative Balance Sheet:

	Balance at Beginning of Year	Balance at End of Year
Cash (131)	$ 2,126,637	$ 6,429,345
Working Funds (135)	23,067	23,061
Temporary Cash Investments (136)	104,000,000	120,000,000
	$ 106,149,704	$ 126,452,406
	2013	2014
Cash paid during the year:		
Interest	$ 96,535,309	$ 108,145,039
AFDC - Borrowed	(6,891,655)	(22,440,859)
	$ 89,643,654	$ 85,704,180
Income Taxes	$ 10,360,000	$ 22,050,850
Non-cash investing and financing activities:		
Accrued capital additions	$ 84,469,331	$ 70,433,493
Accrued dividends payable	22,378,496	22,888,174
Accrued sales tax refund related to Tucannon River Wind Farm	—	23,355,665
Preliminary engineering transferred to Construction work in Progress from Other noncurrent assets	9,379,785	404,336

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 sells electricity and natural gas in the wholesale market to utilities, brokers, and power marketers. PGE operates as a single segment, with revenues and costs related to its business activities maintained and analyzed on a total electric operations basis. PGE's corporate headquarters is located in Portland, Oregon and its service area is located entirely within Oregon. PGE's service area includes 52 incorporated cities, of which Portland and Salem are the largest, within a state-approved service area allocation of approximately 4,000 square miles. As of December 31, 2014, PGE served 842,273 retail customers with a service area population of approximately 1.8 million, comprising approximately 46% of the state's population.

As of December 31, 2014, PGE had 2,600 employees, with 780 employees covered under two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 743 and 37 employees and expire in February 2016 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 current and non-current 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.

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.

Customer Billing Matter

In May 2013, PGE discovered that it had over-billed an industrial customer during a period of several years as a result of a meter configuration error. An analysis of the data determined that the Company’s revenues were overstated by approximately $3 million in 2012 and in 2011, $2 million in 2010, and $1 million in 2009. PGE believes the customer billing error is not material to any annual reporting period. The Company corrected this matter in the second quarter of 2013 as an out of period adjustment, and recorded, as a reduction to Operating Revenues, a refund to the customer in the amount of $9 million.

Subsequent events

PGE has evaluated the impact of events occurring after December 31, 2014 up to February 12, 2015, the date that the Company’s U.S. GAAP financial statements were issued and has updated such evaluation for disclosure purposes through March 25, 2015. 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 $120 million and $104 million as of December 31, 2014 and 2013, respectively.

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 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 2014 and 2013.

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 sale and purchase transactions that are physically settled are recorded in Operating Revenues and Purchased Power upon settlement, respectively.

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 in the Comparative Balance Sheet and were $11 million and $9 million as of December 31, 2014 and 2013, respectively. Letters of credit provided as collateral are not recorded on the Company's Comparative Balance Sheet and were $30 million and $29 million as of December 31, 2014 and 2013, 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 and fuel for use in generating plants. Fuel inventories include natural gas, oil, and coal. 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.

During the year ended December 31, 2013, PGE charged $52 million of costs previously included in CWIP related to the Cascade Crossing Transmission Project (Cascade Crossing), which was originally proposed as a 215-mile, 500 kV transmission project between Boardman, Oregon and Salem, Oregon. Based on an updated forecast of demand and future transmission capacity in the region, PGE determined in the second quarter of 2013 that the original projections of transmission capacity limitations contemplated in the Company’s 2009 Integrated Resource Plan, as acknowledged by the OPUC, were not likely to fully materialize. As a result, PGE and Bonneville Power Administration (BPA) worked toward refining the scope of the project and executed a non-binding memorandum of understanding (MOU) in May 2013. In connection with the MOU, the parties explored a new option under which BPA could provide PGE with ownership of approximately 1,500 MW of transmission capacity rights. As a result of the changed conditions reflected in the MOU, PGE also suspended permitting and development of Cascade Crossing and charged the capitalized costs related to Cascade Crossing to expense in the second quarter of 2013. In October 2013, the parties determined that they would not be able to reach an agreement on the financial terms for the proposed ownership of transmission capacity rights and, therefore, agreed to discontinue discussions on this option. The Company has determined that, under current conditions, the best option for meeting its transmission needs is to continue to acquire transmission service offered under BPA’s Open Access Transmission Tariff. PGE has determined that it will not seek recovery of these costs.

PGE records AFDC, which is intended to represent the Company’s cost of funds used for construction purposes and is 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 7.4% in 2014 and 7.5% in 2013. AFDC from borrowed funds was $22 million in 2014 and $7 million in 2013 and is reflected as a reduction to Interest Charges. AFDC from equity funds was $37 million in 2014 and $13 million in 2013 and is included in Other Income.

Costs disallowed for recovery in customer prices, if any, are charged to expense at the time such disallowance is probable.

Depreciation and Amortization

Depreciation is computed using the straight-line method, based upon original cost, and includes an estimate for cost of removal and expected salvage. Depreciation expense as a percent of the related average depreciable plant in service was 3.6% in 2014 and 3.7% in 2013. Estimated asset retirement removal costs included in depreciation expense were $57 million in 2014 and $55 million in 2013.

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.

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	87
Wind	27
Transmission	53
Distribution	40
General	13

The original cost of depreciable property units, net of any related salvage value, is charged to accumulated depreciation when property is retired and removed from service. 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 $191 million and $170 million as of December 31, 2014 and 2013, respectively, with amortization expense of $25 million in 2014 and $22 million in 2013. Future estimated amortization expense as of December 31, 2014 is as follows: $35 million in 2015; $33 million in 2016; $29 million in 2017; $28 million in 2018; and $22 million in 2019.

Marketable Securities

All of PGE's investments in marketable securities in the Non-qualified benefit plan trust and Nuclear decommissioning trust, included in Other Special Funds 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 Other Income, net. 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. The cost of securities sold is based on the average cost method.

Regulatory Accounting

Regulatory Assets and Liabilities

As a rate-regulated enterprise, the Company applies regulatory accounting, resulting in regulatory assets or 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 Statements of Income; and is net of ii) wholesale sales, which are classified as Operating Revenues in the Statements 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 9.75% for 2014 and 10% for 2013.

Any estimated refund to customers pursuant to the PCAM is recorded as a reduction in Operating 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.

For 2014, actual NVPC was below baseline NVPC by $7 million, which is within the established deadband range. Accordingly, no estimated refund to customers was recorded as of December 31, 2014. A final determination regarding the 2014 PCAM results will be made by the OPUC through a public filing and review in 2015.

For 2013, actual NVPC was above baseline NVPC by $11 million, which is within the established deadband range. Accordingly, no estimated collection from customers was recorded as of December 31, 2013. A final determination regarding the 2013 PCAM results was made by the OPUC through a public filing and review in 2014, which confirmed no collection from customers pursuant to the PCAM for 2013.

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 it is incurred if a reasonable estimate of fair value can be made. 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 on the Comparative Balance Sheet with a corresponding offset to ARO. Such estimates are revised periodically, with actual expenditures charged to the ARO as incurred.

The estimated capitalized costs of AROs are depreciated over the estimated life of the related asset, which is included in Depreciation Expense for Asset Retirement Costs in the Statement of Income. Changes in the ARO resulting from the passage of time (accretion) is based on the original discount rate and recognized as an increase in the carrying amount of the liability and as a charge to accretion expense, which is classified as Depreciation Expense for Asset Retirement Costs in the Company's Statement of Income.

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 $39 million as of December 31, 2014 and 2013. See Note 6, Regulatory Assets and Liabilities.

Contingencies

Contingencies are evaluated using the best information available at the time the financial statements are prepared. 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. Legal costs incurred in connection with loss contingencies are expensed as incurred.

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), and 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 $42 million in 2014 and $41 million in 2013.

Retail revenue is billed monthly based on meter readings taken throughout the month. Accrued Utility Revenues represents the revenue earned from the last meter read date through the last day of the month, which has not been billed as of the last day of the month. Accrued Utility Revenues are calculated based on each month's actual net retail system load, 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, there are situations in which PGE 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.

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 is established to reduce deferred tax assets to the "more likely than not" amount expected to be realized in future tax returns.

As 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. These amounts were recognized as net regulatory assets of $89 million and $79 million as of December 31, 2014 and 2013, respectively, and will be included in prices when the temporary differences reverse.

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

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

Recent Accounting Pronouncement

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 in the contract; and v) recognize revenue when or as each performance obligation is satisfied. Companies can transition to the requirements of this ASU either retrospectively or as a cumulative-effect adjustment as of the date of adoption, which is January 1, 2017 for the Company, with early adoption prohibited. The impact on the Company’s financial position, results of operations, or cash flows of the adoption of ASU 2014-09 is not known at this time.

NOTE 3: COMPARATIVE BALANCE SHEET COMPONENTS

Accumulated Provision for Uncollectible Accounts

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

	Years Ended December 31, 2014	2013
Balance as of beginning of year	$ 6	$ 5
Increase in provision	6	6
Amounts written off, less recoveries	(6)	(5)
Balance as of end of year	$ 6	$ 6

Trust Accounts

PGE maintains two trust accounts as follows, 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.

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	
	2014	2013	2014	2013
Cash equivalents	$ 65	$ 59	$ —	$ —
Marketable securities, at fair value:				
Equity securities	—	—	6	8
Debt securities	25	23	—	1
Insurance contracts, at cash surrender value	—	—	26	26
	$ 90	$ 82	$ 32	$ 35

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, 2014 and 2013, and then classifies these financial assets and liabilities based on a fair value hierarchy. The fair value hierarchy is used to prioritize the inputs to the valuation techniques used to measure fair value. These three broad 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 reporting date.

Level 2 Pricing inputs include those that are directly or indirectly observable in the marketplace as of the reporting 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.

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, 2014 and 2013, except those transfers from Level 3 to Level 2 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, 2014			
	Level 1	**Level 2**	**Level 3**	**Total**
Assets:				
Nuclear decommissioning trust (1):				
Money market funds	$ —	$ 65	$ —	$ 65
Debt securities:				
Domestic government	7	7	—	14
Corporate credit	—	11	—	11
Non-qualified benefit plan trust (2):				
Equity securities:				
Domestic	4	1	—	5
International	1	—	—	1
Assets from price risk management activities (1) (3):				
Electricity	—	4	1	5
Natural gas	—	2	—	2
	$ 12	$ 90	$ 1	$ 103
Liabilities - Liabilities from price risk management activities (1) (3):				
Electricity	$ —	$ 32	$ 80	$ 112
Natural gas	—	95	21	116
	$ —	$ 127	$ 101	$ 228

(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) Excludes insurance policies of $26 million, which are recorded at cash surrender value.
(3) For further information, see Note 5, Price Risk Management.

	As of December 31, 2013			
	Level 1	Level 2	Level 3	Total
Assets:				
Nuclear decommissioning trust (1):				
Money market funds	$ —	$ 59	$ —	$ 59
Debt securities:				
Domestic government	6	8	—	14
Corporate credit	—	9	—	9
Non-qualified benefit plan trust (2):				
Equity securities:				
Domestic	4	3	—	7
International	1	—	—	1
Debt securities - domestic government	1	—	—	1
Assets from price risk management activities (1) (3):				
Electricity	—	9	1	10
Natural gas	—	4	—	4
	$ 12	$ 92	$ 1	$ 105
Liabilities - Liabilities from price risk management activities (1) (3):				
Electricity	$ —	$ 10	$ 117	$ 127
Natural gas	—	40	23	63
	$ —	$ 50	$ 140	$ 190

(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) Excludes insurance policies of $26 million, which are recorded at cash surrender value.
(3) 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:

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. Money market funds are classified as Level 2 in the fair value hierarchy as the securities are traded in active markets of similar securities but are not directly valued using quoted market prices.

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 reporting 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 primarily 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 reporting date. Principal markets for equity prices include published exchanges such as NASDAQ and the New York Stock Exchange (NYSE). Certain mutual fund assets included in commingled trusts or separately managed accounts are classified as Level 2 in the fair value hierarchy as pricing inputs are directly or indirectly observable in the marketplace.

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 net power costs 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, 2014:							
Electricity physical forward	$ —	$ 77	Discounted cash flow	Electricity forward price (per MWh)	$ 11.97	$ 122.72	$ 37.43
Natural gas financial swaps	—	21	Discounted cash flow	Natural gas forward price (per Dth)	2.88	4.86	3.41
Electricity financial futures	1	3	Discounted cash flow	Electricity forward price (per MWh)	11.97	39.26	27.88
	$ 1	$ 101					
As of December 31, 2013:							
Electricity physical forward	$ —	$ 103	Discounted cash flow	Electricity forward price (per MWh)	$ 9.63	$ 77.95	$ 40.18
Natural gas financial swaps	—	23	Discounted cash flow	Natural gas forward price (per Dth)	3.16	4.49	3.71
Electricity financial futures	1	14	Discounted cash flow	Electricity forward price (per MWh)	9.63	46.07	33.01
	$ 1	$ 140					

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, the Company uses internally-developed price curves that employ the mid-point of the market's bid-ask spread derived using observed transactions in active markets, as well as historical experience as a participant in those markets. These internally-developed price curves are validated against nonbinding broker quotes, market data from a regulated exchange and benchmark price assessments from a pricing vendor. For certain longer term contracts, observable, liquid market transactions are not available for the duration of the delivery period. In such circumstances, the Company uses internally-developed price curves, which utilize observable data and regression techniques to derive future prices. In addition, changes in the fair value measurement of price risk management assets and liabilities are analyzed and reviewed on a monthly basis by the Company. This process includes analytical review of changes in commodity prices as well as procedures to analyze and identify the reasons for the changes over specific reporting periods.

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, 2014	Years Ended December 31, 2013
Net liabilities from price risk management activities as of beginning of year	$ 139	$ 16
Net realized and unrealized losses *	15	134
Settlements	(4)	(1)
Net transfers out of Level 3 to Level 2	(50)	(10)
Net liabilities from price risk management activities as of end of year	$ 100	$ 139
Level 3 net unrealized losses that have been fully offset by the effect of regulatory accounting	$ 12	$ 133

* Includes realized losses, net of $3 million in 2014 and $1 million in 2013.

Transfers into Level 3 occur when significant inputs used to value the Company's derivative instruments become less observable, such as a delivery location becoming significantly less liquid. During the years ended December 31, 2014 and 2013, there were no significant transfers into Level 3 from Level 2. Transfers out of Level 3 occur when the significant inputs become more observable, such as when the time between the valuation date and the delivery term of a transaction becomes shorter. PGE records transfers 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 FMBs and Pollution Control Bonds 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 is classified as Level 3 fair value measurement and is estimated based on the terms of the loans and the Company's creditworthiness. These significant unobservable inputs to the Level 3 fair value measurement include the interest rate and the length of the loan. The estimated fair value of the Company's unsecured term bank loans approximates their carrying value.

As of December 31, 2014, the carrying amount of PGE's long-term debt was $2,501 million and its estimated aggregate fair value was $2,901 million, consisting of $2,596 million and $305 million classified as Level 2 and Level 3, respectively, in the fair value hierarchy. As of December 31, 2013, the carrying amount of PGE's long-term debt was $1,916 million and its estimated aggregate fair value was $2,074 million, all 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 generating resources 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 fuel and power purchases and sales resulting from economic dispatch decisions for its own generation. As a result of this ongoing business activity, PGE is exposed to commodity price risk and foreign currency exchange rate risk, where adverse changes in prices and/or rates may affect the Company's financial position, performance, or cash flow.

PGE utilizes derivative instruments in its wholesale electric utility activities to manage its exposure to commodity price risk and foreign exchange rate risk in order to manage volatility in net power costs for its retail customers. These derivative instruments may include forward, futures, swap, and option contracts for electricity, natural gas, oil and foreign currency, which are recorded at fair value on the Comparative Balance Sheet, with changes in fair value recorded in the Statement of Income. In accordance with ratemaking and cost recovery processes authorized by the OPUC, PGE 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. PGE 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, 2014	As of December 31, 2013
Current assets:		
Commodity contracts:		
Electricity	$ 4	$ 9
Natural gas	2	4
Total current derivative assets	6	13
Noncurrent assets:		
Commodity contracts:		
Electricity	1	1
Total noncurrent derivative assets	1	1
Total derivative assets not designated as hedging instruments	$ 7	$ 14
Total derivative assets	$ 7	$ 14
Current liabilities:		
Commodity contracts:		
Electricity	$ 54	$ 20
Natural gas	52	29
Total current derivative liabilities	106	49
Noncurrent liabilities:		
Commodity contracts:		
Electricity	58	107
Natural gas	64	34
Total noncurrent derivative liabilities	122	141
Total derivative liabilities not designated as hedging instruments	$ 228	$ 190
Total derivative liabilities	$ 228	$ 190

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,					
	2014			2013		
Commodity contracts:						
Electricity		16	MWh		14	MWh
Natural gas		127	Dth		106	Dth
Foreign currency exchange	$	7	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, these agreements provide for the net settlement of all related contractual obligations with a 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, which are excluded from the offsetting table below.

Information related to price risk management liabilities subject to master netting agreements is as follows (in millions):

	Gross Amounts Recognized	Gross Amounts Offset	Net Amounts Presented	Gross Amounts Not Offset in Comparative Balance Sheet		Net Amount
				Derivatives	Cash Collateral(1)	
As of December 31, 2014:						
Liabilities:						
Commodity contracts:						
Electricity(2)	$ 55	$ —	$ 55	$ (55)	$ —	$ —
Natural gas(2)	17	—	17	(17)	—	—
	$ 72	$ —	$ 72	$ (72)	$ —	$ —
As of December 31, 2013:						
Liabilities:						
Commodity contracts:						
Electricity(2)	$ 91	$ —	$ 91	$ (91)	$ —	$ —
Natural gas(2)	1	—	1	(1)	—	—
	$ 92	$ —	$ 92	$ (92)	$ —	$ —

(1) As of December 31, 2014 and 2013, the Company had collateral posted of $11 million and $7 million, respectively, which consists entirely of letters of credit.

(2) Included in Long-Term portion of Derivative Instrument Liabilities.

Net realized and unrealized losses 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,	
	2014	2013
Commodity contracts:		
Electricity	$ 13	$ 78
Natural Gas	72	28
Foreign currency exchange	—	1

Net unrealized losses and certain net realized losses presented in the table above are offset within the Statement of Income by the effects of regulatory accounting. Of the net loss recognized in net income for the years ended December 31, 2014 and 2013, $83 million and $120 million, respectively, have been offset.

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, 2014 related to PGE's derivative activities would be realized as a result of the settlement of the underlying derivative instrument (in millions):

	2015	2016	2017	2018	2019	Thereafter	Total
Commodity contracts:							
Electricity	$ 50	$ 19	$ 6	$ 5	$ 5	$ 22	$ 107
Natural gas	49	44	18	3	—	—	114
Net unrealized loss	$ 99	$ 63	$ 24	$ 8	$ 5	$ 22	$ 221

PGE's secured and unsecured debt is currently rated at investment grade by Moody's Investors Service (Moody's) and Standard & Poor's Ratings Services (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 and some other counterparties will 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, 2014 was $216 million, for which the Company had posted $29 million in collateral, consisting primarily of letters of credit. If the credit-risk-related contingent features underlying these agreements were triggered at December 31, 2014, the cash requirement to either post as collateral or settle the instruments immediately would have been $213 million. As of December 31, 2014, PGE had posted an additional $11 million in cash collateral for derivative instruments with no credit-risk-related contingent features, which 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,	
	2014	2013
Assets from price risk management activities:		
Counterparty A	63 %	53 %
Counterparty B	14	6
	77 %	59 %
Liabilities from price risk management activities:		
Counterparty C	22 %	43 %
Counterparty D	12	11
	34 %	54 %

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, 2014		As of December 31, 2013	
Regulatory assets:					
Price risk management (2)	3 years	$	221	$	176
Pension and other postretirement plans (2)	(3)		247		194
Deferred income taxes (2)	(4)		89		79
Deferred broker settlements	1 year		4		13
Deferred capital projects	1 year		19		34
Other (5)	Various		34		20
Total regulatory assets		$	614	$	516
Regulatory liabilities:					
Trojan decommissioning activities	2 years		57		49
Asset retirement obligations (6)	(4)		39		39
Other	Various		32		23
Total regulatory liabilities		$	128	$	111

(1) As of December 31, 2014.
(2) Does not include a return on investment.
(3) Recovery expected over the average service life of employees. For additional information, see Note 2, Summary of Significant Accounting Policies.
(4) Recovery expected over the estimated lives of the assets.
(5) Of the total other unamortized regulatory asset balances, a return is recorded on $33 million and $16 million as of December 31, 2014 and 2013, respectively.
(6) Included in rate base for ratemaking purposes.

As of December 31, 2014, PGE had regulatory assets of $63 million earning a return on investment at the following rates: i) $33 million earning a return by inclusion in rate base; ii) $19 million at PGE's cost of debt of 5.54%; iii) $9 million at the approved rate for deferred accounts under amortization, ranging from 1.47% to 1.77%, depending on the year of approval; and iv) $2 million at PGE's cost of capital of 7.65%.

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.

Deferred capital projects represents costs related to four capital projects that were deferred for future accounting treatment pursuant to the Company's 2011 General Rate Case. The recovery of these project costs in customer prices began January 1, 2014.

Trojan decommissioning activities represents proceeds received for the settlement of a legal matter concerning the reimbursement from the United States Department of Energy of certain monitoring costs incurred related to spent nuclear fuel at Trojan. The proceeds will be returned to customers over a three-year period beginning January 1, 2015 and offset amounts previously collected from customers in relation to Trojan decommissioning activities. To conform with the 2014 presentation, PGE reclassified tax credits to be returned to customers related to the operation of the ISFSI in the amount of $8 million from Other to Trojan decommissioning activities in the regulatory liabilities section as of December 31, 2013 in the preceding table.

Asset retirement obligations represent 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,	
	2014	**2013**
Trojan decommissioning activities	$ 41	$ 41
Utility Plant	64	49
Non-utility property	11	10
Asset retirement obligations	$ 116	$ 100

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 United States Department of Energy (USDOE) facility is complete, which is not expected prior to 2033.

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 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 were seeking approximately $112 million in damages incurred through 2009.

A trial before the U.S. Court of Federal Claims concluded in 2012, with the U.S. Court of Federal Claims issuing a judgment awarding certain damages to the Plaintiffs. In 2013, the Plaintiffs received $70 million for the settlement of this matter. The settlement agreement also provided for a process to submit claims for allowable costs for the period 2010 through 2013, and was subsequently extended to cover 2014 through 2016. In 2014, the Plaintiffs received $9 million for costs related to 2010 through 2013. The Company will seek recovery of any costs for subsequent periods in future extensions of the agreement.

PGE has received proceeds of $50 million related to its share in this legal matter, with $44 million received in 2013 and $6 million received in 2014. Such funds were deposited into the Nuclear decommissioning trust and 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 the $50 million of 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 is not impacted by the outcome of this legal matter because the proceeds received in connection with the settlement of this legal matter are 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 where disposal is governed by environmental regulation. During 2014, the Company incurred AROs totaling $8 million related to the three new generating resources: Port Westward Unit 2 (PW2), Tucannon River Wind Farm (Tucannon River), and Carty Generating Station (Carty).

In December 2014 and 2013, PGE increased its ARO related to Boardman by $7 million and $4 million, respectively, in connection with the acquisition of additional interests in Boardman, with corresponding increases in the cost basis of the plant, included in Utility Plant on the Comparative Balance Sheet. For additional information regarding the Company's acquisition of additional interests in Boardman, see Note 15, Jointly-owned Plant.

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,	
	2014	**2013**
Balance as of beginning of year	$ 100	$ 94
Liabilities incurred	15	4
Liabilities settled	(3)	(4)
Accretion expense	6	6
Revisions in estimated cash flows	(2)	—
Balance as of end of year	$ 116	$ 100

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 Depreciation and Amortization of Electric Plant.

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

PGE has credit facilities with an aggregate capacity of $700 million as follows:

- A $400 million revolving credit facility, which is scheduled to terminate in November 2018; and
- A $300 million revolving credit facility, which is scheduled to terminate in December 2017.

Pursuant to the terms of the agreements, both revolving credit facilities may be used for general corporate purposes and as backup for commercial paper borrowings, and also 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. Both revolving credit facilities contain two, one-year extensions subject to approval by the banks, require annual fees based on PGE's unsecured credit ratings, and contain 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, 2014, PGE was in compliance with this covenant with a 56.7% debt to total capital ratio.

PGE classifies any borrowings under the revolving credit facilities and outstanding commercial paper as Notes Payable in the

Comparative Balance Sheet. As of December 31, 2014, PGE had no borrowings or commercial paper outstanding, $20 million of letters of credit issued, and an aggregate available capacity of $680 million under the revolving credit facilities.

In addition, PGE has two one-year $30 million letter of credit facilities, under which the Company can request letters of credit for original terms not to exceed one year. The issuance of such letters of credit are subject to the approval of the issuing institution. As of December 31, 2014, $56 million of letters of credit had been issued under these facilities.

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 credit facilities.

Pursuant to an order issued by the FERC, the Company is authorized to issue short-term debt up to $900 million through February 6, 2016. 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.

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

	Years Ended December 31,	
	2014	**2013**
Average daily amount of Notes Payable outstanding	$ —	$ 9
Weighted daily average interest rate *	—%	0.4%
Maximum amount outstanding during the year	$ —	$ 54

* 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,	
	2014	**2013**
First Mortgage Bonds, rates range from 3.46% to 9.31%, with a weighted average rate of 5.42% in 2014 and 5.62% in 2013, due at various dates through 2048	$ 2,075	$ 1,795
Pollution Control Revenue Bonds, 5% rate, due 2033	142	148
Pollution Control Revenue Bonds owned by PGE	(21)	(27)
Total long-term debt	$ 2,501	$ 1,916

First Mortgage Bonds—During 2014, PGE issued a total of $280 million of FMBs, consisting of the following:

- In November, issued $80 million of 3.51% Series FMBs due 2024;
- In October, issued $100 million of 4.44% Series FMBs due 2046; and
- In August, issued $100 million of 4.39% Series FMBs due 2045.

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 January 2015, the Company issued $75 million of 3.55% Series FMBs due 2030.

Unsecured term bank loans—During 2014, PGE obtained four term loans pursuant to a credit agreement in an aggregate principal amount of $305 million. The term loan interest rates are set at the beginning of the interest period for periods ranging from one- to six-months, as selected by PGE and are based on the London Interbank Offered Rate (LIBOR) plus 70 basis points, with no other fees. The credit agreement expires October 30, 2015, 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. Interest is payable monthly on the unsecured term bank loans.

Pollution Control Revenue Bonds—In January 2014, PGE retired $6 million of Pollution Control Revenue Bonds (PCBs). The Company has the option to remarket through 2033 the $21 million of PCBs held by PGE as of December 31, 2014. 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, 2014, the future minimum principal payments on long-term debt are as follows (in millions):

Years ending December 31:		
2015	$	375
2016		67
2017		58
2018		75
2019		300
Thereafter		1,626
	$	2,501

NOTE 10: EMPLOYEE BENEFITS

Pension and Other Postretirement Plans

Defined Benefit Pension Plan—PGE sponsors a non-contributory defined benefit pension plan. The plan 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 which are reviewed annually and are updated as appropriate, with the measurement date of December 31.

PGE made no contributions to the pension plan in 2014 and 2013. No contributions to the pension plan are expected in 2015.

In 2014, the Company offered certain eligible participants of 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 paying 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 which are reviewed annually with PGE’s consulting actuaries and trust investment consultants 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, the participants’ accounts are credited with 58% of the value of the employee’s accumulated sick time as of April 30, 2004, 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. These trust assets 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 which 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):

	2014			2013		
	NQBP	Other NQBP	Total	NQBP	Other NQBP	Total
Non-qualified benefit plan trust	$ 15	$ 17	$ 32	$ 16	$ 19	$ 35
Non-qualified benefit plan liabilities	27	80	107	24	79	103

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. In addition, the Board also 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,			
	2014		2013	
	Actual	Target *	Actual	Target *
Defined Benefit Pension Plan:				
Equity securities	66 %	67 %	67 %	67 %
Debt securities	34	33	33	33
Total	100 %	100 %	100 %	100 %
Other Postretirement Benefit Plans:				
Equity securities	66 %	67 %	58 %	58 %
Debt securities	34	33	42	42
Total	100 %	100 %	100 %	100 %
Non-Qualified Benefits Plans:				
Equity securities	19 %	13 %	24 %	16 %
Debt securities	1	7	1	9
Insurance contracts	80	80	75	75
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.

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	Total
As of December 31, 2014:				
Defined Benefit Pension Plan assets:				
Money market funds	$ —	$ 6	$ —	$ 6
Equity securities:				
Domestic	$ 42	$ 146	$ —	$ 188
International	—	171	—	171
Debt securities:				
Domestic government and corporate credit	—	197	—	197
Private equity funds	—	—	29	29
	$ 42	$ 520	$ 29	$ 591
Other Postretirement Benefit Plans assets:				
Money market funds	$ —	$ 6	$ —	$ 6
Equity securities:				
Domestic	10	1	—	11
International	10	—	—	10
Debt securities—Domestic government	5	—	—	5
	$ 25	$ 7	$ —	$ 32
As of December 31, 2013:				
Defined Benefit Pension Plan assets:				
Equity securities:				
Domestic	$ 166	$ 19	$ —	$ 185
International	185	—	—	185
Debt securities:				
Domestic government and corporate credit	—	181	—	181
Corporate credit	14	—	—	14
Private equity funds	—	—	31	31
	$ 365	$ 200	$ 31	$ 596
Other Postretirement Benefit Plans assets:				
Money market funds	$ —	$ 10	$ —	$ 10
Equity securities:				
Domestic	8	2	—	10
International	9	—	—	9
Debt securities—Domestic government	3	—	—	3
	$ 20	$ 12	$ —	$ 32

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 methods are used in valuation of each asset class of 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, certificates of deposit, and commercial paper. Money market funds held in the trusts are classified as Level 2 instruments as they are traded in an active market of similar securities but are not directly valued using quoted prices.

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 commingled trusts or separately managed accounts are classified as Level 2 securities due to pricing inputs that are not directly or indirectly observable in the marketplace.

Debt securities—PGE invests in highly-liquid United States treasury and corporate credit mutual fund securities to support the investment objectives of the trusts. These securities are classified as Level 1 instruments due to the highly observable nature of pricing in an active market.

Fair values for Level 2 debt securities, including municipal debt and corporate credit securities, mortgage-backed securities and asset-backed securities are determined by evaluating pricing data, such as broker quotes, for similar securities adjusted for observable differences. Significant inputs used in valuation models generally include benchmark yield and issuer spreads. The external credit rating, coupon rate, and maturity of each security are considered in the valuation if applicable.

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, venture capital, buyout and special situations. Private equity investments are classified as Level 3 securities due to fund valuation methodologies that utilize discounted cash flow, market comparable and limited secondary market pricing to develop estimates of fund valuation. PGE valuation of individual fund performance compares stated fund performance against published benchmarks.

Changes in the fair value of assets held by the pension plan classified as Level 3 in the fair value hierarchy, which consists of Private equity funds, were as follows (in millions):

	Years Ended December 31,	
	2014	**2013**
Level 3 balance as of beginning of year	$ 31	$ 32
Unrealized gains, net	2	4
Realized gains (losses), net	3	(2)
Sales, net	(7)	(3)
Level 3 balance as of end of year	$ 29	$ 31

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, 2014 and 2013. 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	
	2014	**2013**	**2014**	**2013**	**2014**	**2013**
Benefit obligation:						
As of January 1	$ 705	$ 728	$ 77	$ 84	$ 24	$ 27
Service cost	15	17	2	2	—	—
Interest cost	34	30	4	3	1	1
Participants' contributions	—	—	1	2	—	—
Actuarial (gain) loss	72	(38)	4	(9)	5	(2)
Contractual termination benefits	—	—	1	1	—	—
Benefit payments	(48)	(32)	(6)	(6)	(3)	(2)
Administrative expenses	(1)	—	—	—	—	—
As of December 31	$ 777	$ 705	$ 83	$ 77	$ 27	$ 24
Fair value of plan assets:						
As of January 1	$ 596	$ 537	$ 32	$ 28	$ 16	$ 15
Actual return on plan assets	44	91	1	5	1	3
Company contributions	—	—	4	3	1	—
Participants' contributions	—	—	1	2	—	—
Benefit payments	(48)	(32)	(6)	(6)	(3)	(2)
Administrative expenses	(1)	—	—	—	—	—
As of December 31	$ 591	$ 596	$ 32	$ 32	$ 15	$ 16
Unfunded position as of December 31	$ (186)	$ (109)	$ (51)	$ (45)	$ (12)	$ (8)
Accumulated benefit plan obligation as of December 31	$ 691	$ 631	N/A	N/A	$ 27	$ 24
Amounts included in comprehensive income:						
Net actuarial (gain) loss	$ 67	$ (89)	$ 5	$ (11)	$ 5	$ (1)
Amortization of net actuarial loss	(17)	(24)	(1)	(1)	(1)	(1)
Amortization of prior service cost	—	—	(1)	(1)	—	—
	$ 50	$ (113)	$ 3	$ (13)	$ 4	$ (2)
Amounts included in AOCL*:						
Net actuarial loss	$ 236	$ 186	$ 10	$ 6	$ 13	$ 9
Prior service cost	—	—	1	2	—	—
	$ 236	$ 186	$ 11	$ 8	$ 13	$ 9
Assumptions used:						
Discount rate for benefit obligation	4.02 %	4.84 %	3.07 %-4.10 %	3.46 %-4.96 %	4.02 %	4.84 %
Discount rate for benefit cost	4.84 %	4.24 %	3.46 %-4.96 %	2.77 %-4.13 %	4.84 %	4.24 %
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 %	6.37 %	6.46 %	N/A	N/A
Long-term rate of return on plan assets for benefit cost	7.50 %	8.25 %	6.46 %	5.89 %	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	
	2014	2013	2014	2013	2014	2013
Service cost	$ 15	$ 17	$ 2	$ 2	$ —	$ —
Interest cost on benefit obligation	34	30	4	3	1	1
Expected return on plan assets	(39)	(40)	(2)	(1)	—	—
Amortization of prior service cost	—	—	1	1	—	—
Amortization of net actuarial loss	17	24	1	1	1	1
Net periodic benefit cost	$ 27	$ 31	$ 6	$ 6	$ 2	$ 2

PGE estimates that $23 million will be amortized from AOCL into net periodic benefit cost in 2015, consisting of a net actuarial loss of $20 million for pension benefits, $1 million for non-qualified benefits and $1 million for other postretirement benefits, and prior service cost of $1 million 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					
	2015	2016	2017	2018	2019	2020 - 2024
Defined benefit pension plan	$ 35	$ 37	$ 38	$ 40	$ 41	$ 221
Other postretirement benefits	5	5	5	5	5	26
Non-qualified benefit plans	2	2	2	2	3	9
Total	$ 42	$ 44	$ 45	$ 47	$ 49	$ 256

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 2014, 7% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2015, and assumed to decrease 0.5% per year thereafter, reaching 5% in 2019; and

- For 2013, 7.5% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2014, and assumed to decrease 0.5% per year thereafter, reaching 5% in 2019.

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 $16 million in 2014 and 2013.

NOTE 11: INCOME TAXES

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

	Years Ended December 31,	
	2014	2013
Current:		
Federal	$ 20	$ 10
State and local	2	—
	22	10
Deferred:		
Federal	26	4
State and local	13	7
	39	11
Income tax expense	$ 61	$ 21

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,	
	2014	2013
Federal statutory tax rate	35.0 %	35.0 %
Federal tax credits	(11.4)	(21.8)
State and local taxes, net of federal tax benefit	3.9	3.4
Flow through depreciation and cost basis differences	(2.3)	2.8
Other	0.8	(2.6)
Effective tax rate	26.0 %	16.8 %

Deferred income tax assets and liabilities consist of the following (in millions):

	As of December 31, 2014	2013
Deferred income tax assets:		
Employee benefits	$ 161	$ 124
Price risk management	91	76
Regulatory liabilities	48	16
Tax credits	13	51
Depreciation and amortization	(6)	5
Other	17	33
Total deferred income tax assets	324	305
Deferred income tax liabilities:		
Depreciation and amortization	686	651
Regulatory assets	211	175
Price risk management	3	6
Employee benefits	1	2
Other	15	15
Total deferred income tax liabilities	916	849
Deferred income tax liability, net	$ (592)	$ (544)

As of December 31, 2014, PGE has federal and state tax credit carryforwards of $10 million and $3 million, respectively, which will expire at various dates from 2021 through 2036.

PGE believes that it is more likely than not that its deferred income tax assets as of December 31, 2014 and 2013 will be realized; accordingly, no valuation allowance has been recorded. As of December 31, 2014 and 2013, PGE had no unrecognized tax benefits.

PGE and its subsidiaries file federal income tax returns, state income tax returns in certain jurisdictions, including Oregon, California, 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.

Further guidance was issued during 2014 that clarified final regulations issued on September 13, 2013, regarding the deduction and capitalization of expenditures related to tangible property. The final regulations under Internal Revenue Code Sections 162, 167 and 263(a) apply to amounts paid to acquire, produce, or improve tangible property, as well as dispositions of such property and have been adopted by PGE as of the January 1, 2014 effective date. The adoption of these regulations, including the consideration of subsequent guidance, did not have a material impact on the Company's financial position, results of operations, or cash flows.

House of Representatives Bill 5771—The Tax Increase Prevention Act of 2014 was signed into law on December 19, 2014. PGE has examined the new law and while the Company intends to take advantage of some of the provisions, no provision will materially impact its financial position.

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 connection with such public offering, the underwriters exercised their over-allotment option in full and PGE issued 1,665,000 shares of its common stock for net proceeds of $47 million. Pursuant to the terms of the EFSA, a forward counterparty borrowed 11,100,000 shares of PGE's common stock from third parties in the open market and sold the shares to a group of underwriters for $29.50 per share, less an underwriting discount equal to $0.96 per share. The underwriters then sold the shares in a public offering. PGE receives proceeds from the sale of common stock when the EFSA is physically settled (described below), and at that time PGE issues new shares of common stock and records the proceeds in equity. Through December 31, 2014, the Company has issued 700,000 shares of its common stock pursuant to the EFSA for net proceeds of $20 million.

Under the terms of the EFSA, PGE may elect to settle the equity forward transactions by means of: i) physical; ii) cash; or iii) net share settlement, in whole or in part, at any time on or prior to June 11, 2015, except in specified circumstances or events that would require physical settlement. To the extent that the transactions are physically settled, PGE would be required to issue and deliver shares of PGE common stock to the forward counterparty at the then applicable forward sale price. The forward sale price was initially determined to be $29.50 per share at the time the EFSA was entered into, and the amount of cash to be received by PGE upon physical settlement of the EFSA is subject to certain adjustments in accordance with the terms of the EFSA.

The EFSA had no initial fair value since it was entered into at the then market price of the common stock. Accordingly, PGE concluded that the EFSA was an equity instrument which does not qualify as a derivative because the EFSA was indexed to the Company's stock. PGE anticipates settling the EFSA through physical settlement on or before June 11, 2015.

As of December 31, 2014, the Company could have physically settled the EFSA by delivering 10,400,000 shares to the forward counterparty in exchange for cash of $275 million. In addition, at December 31, 2014, the Company could have elected to make a cash settlement by paying approximately $119 million, or a net share settlement by delivering approximately 3,135,000 shares of common stock. To the extent that PGE makes a cash or net share settlement, the Company would receive no additional proceeds from the public offering.

Prior to settlement, the potentially issuable shares pursuant to the EFSA will be 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 would be 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 be 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. There are two six-month offering periods each year, 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, 2014, there were 427,021 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, 2014, there were 2,481,110 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, 2012	440,562	22.54
Granted	183,071	29.25
Forfeited	(7,007)	27.15
Vested	(185,536)	20.20
Outstanding as of December 31, 2013	431,090	26.31
Granted	203,410	31.49
Forfeited	(12,278)	29.90
Vested	(158,329)	24.95
Outstanding as of December 31, 2014	463,893	28.96

A total of 4,687,500 shares of common stock were registered for future issuance under the Plan, of which 3,554,884 shares remain available for future issuance as of December 31, 2014.

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, 2014 and 2013.

Performance-based RSUs vest if performance goals are met at the end of a three-year performance period. For grants prior to March 5, 2013, such goals include return on equity relative to allowed return on equity, and regulated asset base growth. Grants on and after March 5, 2013 are based on three equally-weighted metrics: return on equity relative to allowed return on equity; regulated asset growth; and 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:

	2014	2013
Risk-free interest rate	0.6%	0.3%
Expected dividend yield	—%	—%
Expected term (in years)	3.0	3.0
Volatility	12.4% - 23.0%	12.1% - 25.1%

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 134.2% and 117.5% of awarded performance-based RSUs for 2014 and 2013, respectively, with an estimated 5% forfeiture rate.

The total value of performance-based RSUs vested was $3 million for the years ended December 31, 2014 and 2013.

Stock-based compensation was $6 million for the year ended December 31, 2014 and $4 million in 2013, which is included in Administrative and General Expenses in the Statement of Income. 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. The net impact to equity from the income tax payments, partially offset by the issuance of DERs, resulted in a charge to equity of $1 million in 2014 and $2 million in 2013, which is not included in Administrative and General Expenses in the Statement of Income.

As of December 31, 2014, unrecognized stock-based compensation expense was $6 million, of which approximately $4 million and $2 million is expected to be expensed in 2015 and 2016, 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, 2014 or 2013.

NOTE 14: COMMITMENTS AND GUARANTEES

Commitments

As of December 31, 2014, PGE’s estimated future minimum payments pursuant to purchase obligations for the following five years and thereafter are as follows (in millions):

	Payments Due						
	2015	2016	2017	2018	2019	Thereafter	Total
Capital and other purchase commitments	$ 242	$ 21	$ 2	$ 2	$ 2	$ 74	$ 343
Purchased Power:							
Electricity purchases	179	167	140	143	143	833	1,605
Capacity contracts	27	26	6	6	5	20	90
Public utility districts	8	7	5	4	2	23	49
Natural gas	56	37	40	40	36	244	453
Coal and transportation	23	14	11	5	5	—	58
Operating leases	10	11	12	11	8	192	244
Total	$ 545	$ 283	$ 216	$ 211	$ 201	$ 1,386	$ 2,842

Capital and other purchase commitments—Certain commitments have been made for capital and other purchases for 2015 and beyond. Such commitments include those related to hydro licenses, upgrades to generating, distribution and transmission facilities, information systems, and system maintenance work. A large component of these commitments for 2015 are costs associated with the construction of Carty. Termination of these agreements could result in cancellation charges.

Electricity purchases and Capacity contracts—PGE has power purchase contracts with counterparties, which expire at varying dates through 2049, and power capacity contracts through 2019. In addition to the power purchase contracts with counterparties presented in the table, PGE has power sale contracts with counterparties of approximately $43 million that settle as follows: $14 million in 2015; $11 million in 2016 and 2017; and $7 million in 2018.

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, 2014	PGE's Share as of December 31, 2014		Contract Expiration	PGE Cost, including Debt Service	
		Output	Capacity (in MW)		2014	2013
Priest Rapids and Wanapum	$ 1,102	8.6%	163	2052	$ 14	$ 14
Wells	215	19.4	150	2018	10	10
Portland Hydro	4	100.0	36	2017	4	4

The agreements for Priest Rapids and 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 outstanding debt.

Natural gas—PGE has agreements 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 natural gas-fired generating plants (Port Westward Unit 1 (PW1), PW2 and Beaver).

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

Operating leases—PGE has various operating leases associated with its headquarters and certain of its production, transmission, and support facilities. The majority of the future minimum operating lease payments presented in the table consist of i) the corporate headquarters lease, which expires in 2018, but includes renewal period options through 2043, and ii) the Port of St. Helens land lease, where PW1, PW2 and Beaver are located, which expires in 2096. Rent expense was $11 million in 2014 and $9 million in 2013.

The future minimum operating lease payments presented is net of sublease income of: $3 million in 2015; $2 million in 2016; and $1 million in 2017, 2018 and 2019. Sublease income was $3 million in 2014 and 2013.

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, 2014, 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

PGE has interests in three jointly-owned generating facilities. Under the joint operating agreements, 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 Expenses in the Statement of Income.

In 1985, PGE sold a 15% undivided interest in Boardman and a 10.714% undivided interest in the Company's share of the Pacific Northwest Intertie transmission line (jointly, the Facility Assets) to an unrelated third party (Purchaser). Under terms of the original 1985 agreements, on December 31, 2013, PGE acquired the Facility Assets from the Purchaser in exchange for $1 from the Purchaser. PGE assumed responsibility for the ARO related to that 15% interest in Boardman in the amount of $7 million. The acquisition of the 15% interest in Boardman increased the Company's ownership share from 65% to 80% on December 31, 2013. Such transaction is non-cash and is excluded from investing activities in the Statement of Cash Flows for the year ended December 31, 2013.

On December 31, 2014, PGE acquired an additional 10% interest in Boardman from another co-owner, whereby the Company received net cash of $8 million from the co-owner to assume the net liabilities associated with the ownership of this 10% interest. In connection with this transaction, PGE recorded Utility Plant of $7 million, inventory of $4 million, an ARO of $7 million, a regulatory liability of $6 million to be returned to customers in 2015 and 2016, a regulatory liability of $4 million related to future additional decommissioning and environmental costs, and deferred revenue of $2 million. The acquisition of the 10% interest in Boardman increased the Company's ownership share from 80% to 90%.

As of December 31, 2014, 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	$ 656	$ 496	$ —
Colstrip	20.00	1986	520	334	2
Pelton/Round Butte	66.67	1958 / 1964	237	55	8
Total			$ 1,413	$ 885	$ 10

* Excludes AROs and accumulated asset retirement removal costs.

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 where 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.

Trojan Investment Recovery

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

Numerous challenges and appeals were subsequently filed in various state courts on the issue of the OPUC’s authority under Oregon law to grant recovery of, and a return on, the Trojan investment. In 1998, the Oregon Court of Appeals upheld the OPUC’s order authorizing PGE’s recovery of the Trojan investment, but held that the OPUC did not have the authority to allow the Company to recover a return on the Trojan investment and remanded the case to the OPUC for reconsideration.

In 2000, PGE entered into agreements to settle the litigation related to recovery of, and return on, its investment in Trojan. The settlement, which was approved by the OPUC, allowed PGE to remove from its Comparative Balance Sheet the remaining investment in Trojan as of September 30, 2000, along with several largely offsetting regulatory liabilities. After offsetting the investment in Trojan with these liabilities, the remaining Trojan regulatory asset balance of approximately $5 million (after tax) was expensed. As a result of the settlement, PGE’s investment in Trojan was no longer included in prices charged to customers, either through a return of or a return on that investment. The Utility Reform Project (URP) did not participate in the settlement and filed a complaint with the OPUC challenging the settlement agreements. In 2002, the OPUC issued an order (2002 Order) denying all of the URP’s challenges. In 2007, following several appeals by various parties, the Oregon Court of Appeals issued an opinion that remanded the 2002 Order to the OPUC for reconsideration.

The OPUC then issued an order in 2008 (2008 Order) that required PGE to provide refunds, including interest from September 30, 2000, to customers who received service from the Company during the period from October 1, 2000 to September 30, 2001. The Company recorded a charge of $33.1 million in 2008 related to the refund and accrued additional interest expense on the liability until refunds to customers were completed in the first quarter of 2010. The URP and the plaintiffs in the class actions described below separately appealed the 2008 Order to the Oregon Court of Appeals.

On February 6, 2013, the Oregon Court of Appeals issued an opinion that upheld the 2008 Order. On May 31, 2013, the Court of Appeals denied the appellants’ request for reconsideration of the decision. On October 18, 2013, the Oregon Supreme Court granted plaintiffs’ petition seeking review of the February 6, 2013 Oregon Court of Appeals decision.

On October 2, 2014, the Oregon Supreme Court, in a unanimous decision, affirmed the February 6, 2013 Oregon Court of Appeals decision that upheld the OPUC’s 2008 Order. On January 15, 2015, the Oregon Supreme Court denied the plaintiffs petition seeking reconsideration of the October 2, 2014 decision.

Class Actions. In two separate legal proceedings, lawsuits were filed in Marion County Circuit Court against PGE in 2003 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 2006, the Oregon Supreme Court issued a ruling ordering the abatement of the class action proceedings until the OPUC responded to the 2002 Order (described above). The Oregon Supreme Court concluded that the OPUC has primary jurisdiction to determine what, if any, remedy can 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 Oregon Supreme Court 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 Oregon Supreme Court added that, if the OPUC determined that it cannot provide a remedy, the court system may have a role to play. The Oregon Supreme Court also ruled that the plaintiffs retain the right to return to the Marion County Circuit Court for disposition of whatever issues remain unresolved from the remanded OPUC proceedings. The Marion County Circuit Court subsequently abated the class actions in response to the ruling of the Oregon Supreme Court.

The October 2, 2014 Oregon Supreme Court decision described above expressly noted that the plaintiffs in the class action must address any request to lift the abatement with the Marion County Circuit Court. PGE is evaluating how to proceed with respect to the class actions.

PGE believes that the October 2, 2014 Oregon Supreme Court decision has 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 pending, management believes that it is still 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, or to estimate a range of potential loss.

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. Upon appeal of the 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 in detail 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 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 have filed petitions for appeal of these procedural orders with the Ninth Circuit.

Pursuant to a FERC-ordered settlement process, the Company received notice of two claims and reached agreements to settle both claims for an immaterial amount. The FERC approved both settlements during 2012.

Additionally, the settlement between PGE and certain other parties in the California refund case in Docket No. EL00-95, et seq., approved by the FERC in May 2007, resolved all claims between PGE and the California parties named in the settlement, including the California Energy Resource Scheduling division of the California Department of Water Resources (CERS), as to transactions in the Pacific Northwest during the settlement period, January 1, 2000 through June 20, 2001, but did not settle potential claims from other market participants relating to transactions in the Pacific Northwest.

The above-referenced settlements resulted in a release of the Company as a named respondent in the first phase of the remand proceedings, which are limited to initial and direct claims for refunds, but there remains a possibility that additional claims related to this matter could be asserted against the Company in a subsequent phase of the proceeding if refunds are ordered against some or all of the current respondents.

During the first phase of the remand hearing, now completed, two sets of refund proponents, the City of Seattle, Washington (Seattle) and various California parties on behalf of CERS, presented cases alleging that multiple respondents had engaged in unlawful activities and caused severe financial harm that justified the imposition of refunds. After conclusion of the hearing, the presiding Administrative Law Judge issued an Initial Decision on March 28, 2014 finding: i) that Seattle did not carry its *Mobile-Sierra* burden with respect to its refund claims against any of its respondent sellers; and ii) that the California representatives of CERS did not carry their *Mobile-Sierra* burden with respect to one of the two CERS' respondents, but that CERS had produced evidence that the remaining CERS respondent had engaged in unlawful activity in the implementation of multiple transactions and bad faith in the formation of as many as 119 contracts. The Administrative Law Judge scheduled a second phase of the hearing to commence after a final FERC decision on the Initial Decision. The Administrative Law Judge determined that in the second phase the remaining respondent will have an opportunity to produce additional evidence as to why its transactions should be considered legitimate and why refunds should not be ordered. The findings in the Initial Decision are subject to further FERC action. If the FERC requires one or more respondents to make refunds, it is possible that such respondent(s) will attempt to recover similar refunds from their suppliers, including the Company.

Management believes that this matter could result in a loss to the Company in future proceedings. However, management cannot predict whether the FERC will order refunds from any of the current respondents, which contracts would be subject to refunds, the basis on which refunds would be ordered, or how such refunds, if any, would be calculated. Further, management cannot predict whether any current respondents, if ordered to make refunds, will pursue additional refund claims against their suppliers, and, if so, what the basis or amounts of such potential refund claims against the Company would be. Due to these uncertainties, sufficient information is currently not available to determine PGE's liability, if any, or to estimate a range of reasonably possible loss.

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 January 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 is currently undergoing a remedial investigation (RI) and feasibility study (FS) 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.

In March 2012, the LWG submitted a draft FS to the EPA for review and approval. The draft FS, along with the RI, provide the framework for the EPA to determine a clean-up remedy for Portland Harbor that will be documented in a Record of Decision, which the EPA is not expected to issue before 2017.

The draft FS evaluates several alternative clean-up approaches. These approaches would take from two to 28 years with costs ranging from $169 million to $1.8 billion, depending on the selected remedial action levels and the choice of remedy. The draft FS does not address responsibility for the costs of clean-up, allocate such costs among PRPs, or define precise boundaries for the clean-up. Responsibility for funding and implementing the EPA's selected clean-up will be determined after the issuance of the Record of Decision.

Management believes that it is reasonably possible that this matter could result in a loss to the Company. However, due to the uncertainties discussed above, sufficient information is currently not available to determine PGE's liability for the cost of any required investigation or remediation of the Portland Harbor site or to estimate a range of potential loss.

DEQ Investigation of Downtown Reach

The Oregon Department of Environmental Quality (DEQ) has executed a memorandum of understanding with the EPA to administer and enforce clean-up activities for portions of the Willamette River that are upriver from the Portland Harbor Superfund site (the Downtown Reach). In January 2010, the DEQ issued an order requiring PGE to perform an investigation of certain portions of the Downtown Reach. PGE completed this investigation in December 2011 and entered into a consent order with the DEQ in July 2012 to conduct a feasibility study of alternatives for remedial action for the portions of the Downtown Reach that were included within the scope of PGE's investigation. The draft feasibility study report, which describes possible remediation alternatives that range in estimated cost from $3 million to $8 million, was submitted to the DEQ in February 2014. Following the DEQ's evaluation of the draft feasibility study, PGE submitted a final feasibility study to the DEQ in September 2014. The estimated costs in the final feasibility study did not differ significantly from those in the draft feasibility study. Using the Company's best estimate of the probable cost for the remediation effort from the set of alternatives provided in the feasibility study report, PGE has a $3 million reserve for this matter as of December 31, 2014.

Based on the available evidence of previous rate recovery of incurred environmental remediation costs for PGE, as well as for other utilities operating within the same jurisdiction, the Company has concluded that the estimated cost of $3 million to remediate the Downtown Reach is probable of recovery. As a result, the Company also has a regulatory asset of $3 million for future recovery in prices as of December 31, 2014. The Company included recovery of the regulatory asset in its 2015 GRC filed with the OPUC. The final order issued by the OPUC in the 2015 GRC includes revenues to offset the amortization of the regulatory asset over a two year period beginning January 1, 2015.

Alleged Violation of Environmental Regulations at Colstrip

On July 30, 2012, PGE received a Notice of Intent to Sue (Notice) for violations of the Clean Air Act (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 PPL 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, including New Source Review, Title V, and opacity requirements, and states that the Sierra Club and MEIC will: 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 (MDEQ). The Sierra Club and MEIC also asserted violations of opacity provisions of the CAA.

On March 6, 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 are seeking relief that includes 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. In addition, plaintiffs are seeking civil penalties against the co-owners including $32,500 per day for each violation occurring through January 12, 2009, and $37,500 per day for each violation occurring thereafter.

On May 3, 2013, the defendants filed a motion to dismiss 36 of 39 claims alleged in the complaint. In September 2013, the plaintiffs filed a motion for partial summary judgment regarding the appropriate method of calculating emissions increases. Also in September 2013, the plaintiffs filed an amended complaint that withdrew Title V and opacity claims, added claims associated with two 2011 projects, and expanded the scope of certain claims to encompass approximately 40 additional projects. In July 2014, the court denied the defendants' motion to dismiss and the plaintiffs' motion for partial summary judgment.

On August 27, 2014, the plaintiffs filed a second amended complaint to which the defendants' response was filed on September 26, 2014. The second amended complaint continues to seek injunctive relief, declaratory relief, and civil penalties for alleged violations of the federal Clean Air Act. The plaintiffs state in the second amended complaint that it was filed, in part, to comply with the court's ruling on the defendants' motion to dismiss and plaintiffs' motion for partial summary judgment. Discovery in this matter is ongoing with trial now scheduled for November 2015.

Management believes that it is reasonably possible that this matter could result in a loss to the Company. However, due to the uncertainties concerning this matter, PGE cannot predict the outcome or determine whether it would have a material impact on the Company.

Oregon Tax Court Ruling

On September 17, 2012, the Oregon Tax Court issued a ruling contrary to an Oregon Department of Revenue (DOR) interpretation and a current Oregon administrative rule, regarding the treatment of wholesale electricity sales. The underlying issue is whether electricity should be treated as tangible or intangible property for state income tax apportionment purposes. The DOR has appealed the ruling of the Oregon Tax Court to the Oregon Supreme Court. It is uncertain whether the ruling will be upheld. Oral argument occurred in May 2014 and the parties now await a Court decision.

If the ruling is upheld, PGE estimates that its income tax liability could increase by as much as $7 million due to an increase in the tax rate at which deferred tax liabilities would be recognized in future years. During the third quarter of 2013, the Company entered into a closing agreement with the DOR, under which the DOR agreed to the tax apportionment methodology utilized on the tax returns relating to open tax years 2008 through 2012.

Management believes that it is reasonably possible that this matter could result in a loss to the Company. However, due to the uncertainties concerning this matter, PGE cannot predict the outcome.

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 2014/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				(6,375,990)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				1,314,010
3	Preceding Quarter/Year to Date Changes in Fair Value				
4	Total (lines 2 and 3)				1,314,010
5	Balance of Account 219 at End of Preceding Quarter/Year				(5,061,980)
6	Balance of Account 219 at Beginning of Current Year				(5,061,980)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				(2,641,424)
8	Current Quarter/Year to Date Changes in Fair Value				
9	Total (lines 7 and 8)				(2,641,424)
10	Balance of Account 219 at End of Current Quarter/Year				(7,703,404)

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1	(808)		(6,376,798)		
2			1,314,010		
3					
4			1,314,010	104,591,295	105,905,305
5	(808)		(5,062,788)		
6	(808)		(5,062,788)		
7			(2,641,424)		
8					
9			(2,641,424)	175,401,893	172,760,469
10	(808)		(7,704,212)		

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

Comprised of the net amount of the actuarial valuation of $(2,190,020) of non-qualified benefit plans net of taxes of $876,009.

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

Comprised of the net amount of the actuarial valuation of $4,402,374 of non-qualified benefit plans net of taxes of $(1,760,950).

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 2014/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)	8,316,405,437	8,316,405,437
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	8,316,405,437	8,316,405,437
9	Leased to Others		
10	Held for Future Use	4,563,230	4,563,230
11	Construction Work in Progress	417,028,226	417,028,226
12	Acquisition Adjustments	-19,504,255	-19,504,255
13	Total Utility Plant (8 thru 12)	8,718,492,638	8,718,492,638
14	Accum Prov for Depr, Amort, & Depl	3,847,673,122	3,847,673,122
15	Net Utility Plant (13 less 14)	4,870,819,516	4,870,819,516
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	3,656,289,552	3,656,289,552
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	191,383,570	191,383,570
22	Total In Service (18 thru 21)	3,847,673,122	3,847,673,122
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)	3,847,673,122	3,847,673,122

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 2014/Q4

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
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					33

Schedule Page: 200 Line No.: 3 Column: c

In 1985, PGE sold a 15% undivided interest in the Boardman Plant and a 10.714% undivided interest in the Company's share of the Pacific Northwest Intertie transmission line (jointly, the Facility Assets) to an unrelated third party (Purchaser). Under the terms of the original 1985 agreements, on December 31, 2013, PGE acquired the Facility Assets from the Purchaser in exchange for $1 from the Purchaser. This transaction was approved by the FERC on December 19, 2013 through Docket EC14-13-000.

The original cost of the 15% of the Boardman Plant and the 10.714% undivided interest in the Company's share of the Pacific Northwest Intertie transmission line at December 31, 2013 was estimated at $96 million and $2 million, respectively. It was also estimated that these assets were fully depreciated at the time the acquisition was executed since it coincided with the expiration of various agreements under the terms of the original 1985 transaction.

The proposed final accounting entries associated with this transaction were submitted to the FERC on June 27, 2014, in compliance with the accounting under the Uniform System of Accounts (Docket AC14-129-000). On September 29, 2014, FERC approved the final proposed journal entries. In September 2014, the final accounting entries were executed, which increased both Electric plant in service (Account 101) and Accumulated provision for depreciation (Account 108) by $97,861,971 (Steam $94,061,144 and Transmission $3,800,827) with corresponding offsets to Electric plant purchased or sold (Account 102).

In December 2014 PGE acquired an additional 10% undivided interest from another co-owner in the Boardman Plant, and associated equipment and facilities, as well as certain contracts and other rights related to that co-owner's ownership interest in the Boardman Plant.

The original cost of the 10% share of the assets acquired at December 31, 2014 was estimated at $67 million.

On September 19, 2014, PGE filed an application requesting authorization for the acquisition of the rights, titles, and interests associated with this transaction pursuant to section 203(a)(1) of the Federal Power Act (FPA), including proposed accounting entries. On November 14, 2014, the FERC concluded that the proposed transaction was consistent with public interest and authorized the transaction (Docket EC14-147-000). In December 2014, accounting entries were executed which increased Electric plant in service (Account 101) by $67,211,321 (Steam Plant $65,882,727 and Transmission $1,328,594), Accumulated provision for depreciation (Account 108) by $47,707,066 (Steam $46,764,020 and Transmission $943,046), and Construction work in progress (Account 107) by $372,000 with corresponding offsets to Electric plant acquisition adjustments (Account 114).

In accordance with Electric Plant Instruction No. 5 of the Uniform System of Accounts and Electric plant purchased or sold (Account 102), PGE will submit final accounting entries within six months of the date that the proposed transaction was authorized by the FERC.

On January 8, 2014, PGE acquired a 104 kW solar photovoltaic generating facility from Sunway 1, LLC (Sunway). The generating facility and all equipment, materials, and funds relating to Sunway were acquired at net book value.

In accordance with the FERC regulations at 18 CFR Part 101, PGE recorded the acquisition in Electric plant purchased or sold (Account 102). In June 2014, in accordance with Electric plant instruction No. 5 as presented by the FERC, PGE requested approval of proposed journal entries to clear Account 102.

On December 5, 2014 the proposed final accounting entries were approved by the Commission (Docket AC14-119-000). In December 2014 the final entries were executed, which increased Electric plant in service (Account 101) by $42,650, Accumulated provision for depreciation (Account 108) by $42,650, and Construction work in progress account 107 by $181,467, with corresponding offsets to Electric plant purchased or sold (Account 102).

Schedule Page: 200 Line No.: 12 Column: c

See Schedule 200, footnote on Line No.3, Column c

Schedule Page: 200 Line No.: 14 Column: c

See Schedule 200, footnote on Line No.3, Column c

Schedule Page: 200 Line No.: 18 Column: c

See Schedule 200, footnote on Line No.3, Column c

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 2014/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

Line No.	Description of item (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
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			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 2014/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	145,715,660	34,107,753
4	(303) Miscellaneous Intangible Plant	240,173,124	61,538,982
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	385,888,784	95,646,735
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	4,160,671	1,044
9	(311) Structures and Improvements	220,069,745	2,287,225
10	(312) Boiler Plant Equipment	489,631,517	10,426,362
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	161,974,788	-825,011
13	(315) Accessory Electric Equipment	47,140,402	295,379
14	(316) Misc. Power Plant Equipment	12,428,699	276,866
15	(317) Asset Retirement Costs for Steam Production	32,115,880	5,774,101
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	967,521,702	18,235,966
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	49,387,748	1,757,788
29	(332) Reservoirs, Dams, and Waterways	273,609,240	5,404,051
30	(333) Water Wheels, Turbines, and Generators	52,592,695	5,444,840
31	(334) Accessory Electric Equipment	16,790,422	702,169
32	(335) Misc. Power PLant Equipment	2,099,294	1,596
33	(336) Roads, Railroads, and Bridges	10,043,078	861,971
34	(337) Asset Retirement Costs for Hydraulic Production	5,128	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	410,575,232	14,172,415
36	D. Other Production Plant		
37	(340) Land and Land Rights	48,946	
38	(341) Structures and Improvements	116,348,671	46,892,426
39	(342) Fuel Holders, Products, and Accessories	117,332,388	7,521,710
40	(343) Prime Movers		
41	(344) Generators	1,271,604,672	655,099,430
42	(345) Accessory Electric Equipment	67,099,018	27,881,077
43	(346) Misc. Power Plant Equipment	10,961,150	4,110,025
44	(347) Asset Retirement Costs for Other Production	1,563,370	8,490,882
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	1,584,958,215	749,995,550
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	2,963,055,149	782,403,931

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	12,538
49	(352) Structures and Improvements	18,149,759	784,402
50	(353) Station Equipment	245,413,483	18,097,448
51	(354) Towers and Fixtures	46,808,292	302
52	(355) Poles and Fixtures	20,773,920	2,366,936
53	(356) Overhead Conductors and Devices	74,132,476	3,309,154
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)	417,106,979	24,570,780
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	21,606,856	13
61	(361) Structures and Improvements	38,198,947	1,692,534
62	(362) Station Equipment	412,084,913	21,307,378
63	(363) Storage Battery Equipment	351,741	33,192
64	(364) Poles, Towers, and Fixtures	339,907,041	17,379,442
65	(365) Overhead Conductors and Devices	552,023,079	23,452,066
66	(366) Underground Conduit	15,463,125	11,281
67	(367) Underground Conductors and Devices	645,179,499	18,884,402
68	(368) Line Transformers	323,054,436	16,308,662
69	(369) Services	399,676,520	22,612,176
70	(370) Meters	130,446,732	10,996,649
71	(371) Installations on Customer Premises	376,133	
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	60,223,738	11,654,364
74	(374) Asset Retirement Costs for Distribution Plant	476,732	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	2,939,069,492	144,332,159
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	6,750,534	2,913,096
87	(390) Structures and Improvements	95,924,948	12,986,083
88	(391) Office Furniture and Equipment	81,566,654	22,847,627
89	(392) Transportation Equipment	41,632,337	3,779,252
90	(393) Stores Equipment	2,854,812	169,454
91	(394) Tools, Shop and Garage Equipment	12,918,631	2,377,094
92	(395) Laboratory Equipment	9,889,480	-7,024
93	(396) Power Operated Equipment	44,684,701	2,511,103
94	(397) Communication Equipment	85,128,609	11,073,830
95	(398) Miscellaneous Equipment	75,104	78,943
96	SUBTOTAL (Enter Total of lines 86 thru 95)	381,425,810	58,729,458
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)	381,491,099	58,729,458
100	TOTAL (Accounts 101 and 106)	7,086,611,503	1,105,683,063
101	(102) Electric Plant Purchased (See Instr. 8)	-1	1
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)	7,086,611,502	1,105,683,064

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
			179,823,413		3
3,971,063			297,741,043		4
3,971,063			477,564,456		5
					6
					7
			4,161,715		8
324,812	33,784,855		255,817,013		9
1,749,785	87,394,374	-557,386	585,145,082		10
					11
1,564,334	28,860,407		188,445,850		12
49,059	7,772,750		55,159,472		13
	2,131,486	-27,295	14,809,756		14
			37,889,981		15
3,687,990	159,943,872	-584,681	1,141,428,869		16
					17
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					23
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					25
					26
			6,047,627		27
11,000			51,134,536		28
263,720			278,749,571		29
675,651			57,361,884		30
28,780			17,463,811		31
			2,100,890		32
21,224			10,883,825		33
			5,128		34
1,000,375			423,747,272		35
					36
			48,946		37
46,575			163,194,522		38
593,542			124,260,556		39
					40
2,510,274	42,650		1,924,236,478		41
385,946		487,962	95,082,111		42
71,215			14,999,960		43
			10,054,252		44
3,607,552	42,650	487,962	2,331,876,825		45
8,295,917	159,986,522	-96,719	3,897,052,966		46

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
			11,521,146		48
			18,934,161		49
315,401	1,962,334	607,089	265,764,953		50
	1,924,617		48,733,211		51
127,072			23,013,784		52
1,702,376	1,242,470		76,981,724		53
					54
					55
			286,332		56
			34,109		57
2,144,849	5,129,421	607,089	445,269,420		58
					59
6,433			21,600,436		60
32,155			39,859,326		61
2,684,728		1,206,360	431,913,923		62
			384,933		63
3,639,943		-775,226	352,871,314		64
1,567,822		-910,663	572,996,660		65
119,866			15,354,540		66
780,634		-15,881	663,267,386		67
1,335,193		-5,973	338,021,932		68
859,465		-10,346,331	411,082,900		69
624,038		-5,834	140,813,509		70
			376,133		71
					72
561,123		10,315,883	81,632,862		73
			476,732		74
12,211,400		-537,665	3,070,652,586		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
502			9,663,128		86
223,251		301,686	108,989,466		87
9,451,210			94,963,071		88
1,691,753		27,295	43,747,131		89
73,264			2,951,002		90
683,479			14,612,246		91
64,722			9,817,734		92
1,735,851		-301,686	45,158,267		93
451,140			95,751,299		94
6,671			147,376		95
14,381,843		27,295	425,800,720		96
					97
			65,289		98
14,381,843		27,295	425,866,009		99
41,005,072	165,115,943		8,316,405,437		100
					101
					102
					103
41,005,072	165,115,943		8,316,405,437		104

Schedule Page: 204 Line No.: 9 Column: e

In 1985, PGE sold a 15% undivided interest in the Boardman Plant and a 10.714% undivided interest in the Company's share of the Pacific Northwest Intertie transmission line (jointly, the Facility Assets) to an unrelated third party (Purchaser). Under the terms of the original 1985 agreements, on December 31, 2013, PGE acquired the Facility Assets from the Purchaser in exchange for $1 from the Purchaser. This transaction was approved by the FERC on December 19, 2013 through Docket EC14-13-000.

The original cost of the 15% of the Boardman Plant and the 10.714% undivided interest in the Company's share of the Pacific Northwest Intertie transmission line at December 31, 2013 was estimated at $96 million and $2 million, respectively. It was also estimated that these assets were fully depreciated at the time the acquisition was executed since it coincided with the expiration of various agreements under the terms of the original 1985 transaction.

The proposed final accounting entries associated with this transaction were submitted to the FERC on June 27, 2014, in compliance with the accounting under the Uniform System of Accounts (Docket AC14-129-000). On September 29, 2014, FERC approved the final proposed journal entries. In September 2014, the final accounting entries were executed, which increased both Electric plant in service (Account 101) and Accumulated provision for depreciation (Account 108) by $97,861,971 (Steam $94,061,144 and Transmission $3,800,827) with corresponding offsets to Electric plant purchased or sold (Account 102).

In December 2014 PGE acquired an additional 10% undivided interest from another co-owner in the Boardman Plant, and associated equipment and facilities, as well as certain contracts and other rights related to that co-owner's ownership interest in the Boardman Plant.

The original cost of the 10% share of the assets acquired at December 31, 2014 was estimated at $67 million.

On September 19, 2014, PGE filed an application requesting authorization for the acquisition of the rights, titles, and interests associated with this transaction pursuant to section 203(a)(1) of the Federal Power Act (FPA), including proposed accounting entries. On November 14, 2014, the FERC concluded that the proposed transaction was consistent with public interest and authorized the transaction (Docket EC14-147-000). In December 2014, accounting entries were executed which increased Electric plant in service (Account 101) by $67,211,321 (Steam Plant $65,882,727 and Transmission $1,328,594), Accumulated provision for depreciation (Account 108) by $47,707,066 (Steam $46,764,020 and Transmission $943,046), and Construction work in progress (Account 107) by $372,000 with corresponding offsets to Electric plant acquisition adjustments (Account 114).

In accordance with Electric Plant Instruction No. 5 of the Uniform System of Accounts and Electric plant purchased or sold (Account 102), PGE will submit final accounting entries within six months of the date that the proposed transaction was authorized by the FERC.

Schedule Page: 204 Line No.: 10 Column: e

See Schedule 204, Footnote on Line No.9, Column E

Schedule Page: 204 Line No.: 12 Column: e

See Schedule 204, Footnote on Line No.9, Column E

Schedule Page: 204 Line No.: 13 Column: e

See Schedule 204, Footnote on Line No.9, Column E

Schedule Page: 204 Line No.: 14 Column: e

See Schedule 204, Footnote on Line No.9, Column E

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

On January 8, 2014, PGE acquired a 104 kW solar photovoltaic generating facility from Sunway 1, LLC (Sunway). The generating facility and all equipment, materials, and funds relating to Sunway were acquired at net book value.

In accordance with the FERC regulations at 18 CFR Part 101, PGE recorded the acquisition in Electric plant purchased or sold (Account 102). In June 2014, in accordance with Electric plant instruction No. 5 as presented by the FERC, PGE requested approval of proposed journal entries to clear Account 102.

On December 5, 2014 the proposed final accounting entries were approved by the Commission (Docket AC14-119-000). In December 2014 the final entries were executed, which increased Electric plant in service (Account 101) by $42,650, Accumulated provision for depreciation (Account 108) by $42,650, and Construction work in progress account 107 by $181,467, with corresponding offsets to Electric plant purchased or sold (Account 102).

Schedule Page: 204   Line No.: 50   Column: e

See Schedule 204, Footnote on Line No.9, Column E

Schedule Page: 204   Line No.: 51   Column: e

See Schedule 204, Footnote on Line No.9, Column E

Schedule Page: 204   Line No.: 53   Column: e

See Schedule 204, Footnote on Line No.9, Column E

Schedule Page: 204   Line No.: 101   Column: c

See Schedule 204, Footnote on Line No.9, Column E

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				

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	2020	2,817,507
4	Sewell Easement, Washington County, OR	2009	2020	334,928
5	North Bethany, Washington County, OR	2014	2020	538,078
6				
7	Other Land and Land Rights (8 in Number)	Various	Various	329,126
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			4,563,230

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 2014/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	Construct Carty Generating Plant	259,699,209
2	Clackamas PME - North Fork Surface Collector	36,527,701
3	2020 Vision Wave 2 Software Projects - MMS, GIS, OMS	25,620,027
4	Port Westward 2 Generating Plant - 12th Engine	14,922,492
5	Shute Substation - Construct New Distribution Substation	10,866,155
6	Sunset Substation - Capacity Addition	7,572,299
7	Tri-Met Bridge 115-kV Line Construction	4,599,214
8	Beaver Switchyard - Replace 4.15-kV Switchgear	4,519,038
9	Round Butte - Rewind Generators #2 and #3	3,644,726
10	Ruby North Substation - 115-kV Conversion	3,471,324
11	ETRM Risk Management - Software Purchase and Implementation	3,267,310
12	Pelton/Round Butte - Land Mitigation Fund	2,672,396
13	Real Time Dispatch Tool - Software Purchase and Implementation	2,545,533
14	Hayden Island Substation - Capacity Addition	2,499,859
15	River District Infrastructure - Install Vaults and Conduits	2,039,133
16	Substation Fitness Upgrades	2,004,961
17	Tucannon River Wind Facility - Retainage Contract	1,741,216
18	Colstrip Capital Projects	1,721,913
19	Clackamas River PME - Habitat Improvements Lower River Shade Enhancement	1,587,110
20	Oak Grove - Build Harriet Lake Power House	1,556,778
21	Substation TASNET SCADA Replacement Project	1,177,112
22	BI & Data Management - Software Purchase and Implementation	1,150,675
23	Sunset Substation - Replace WR-1 Transformer	1,129,270
24	Communications Equipment - Replace With Cisco VOIP Systems	1,037,784
25	Gresham Substation - Capacity Upgrades	1,026,889
26	Portland Service Center - Facility Upgrades	1,025,662
27	Substation Arc Flash Safety Improvements	1,021,086
28		
29	Minor Projects < 1,000,000 - Represents 4% of CWIP Balance	16,381,354
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	417,028,226

Schedule Page: 216 Line No.: 9 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.

Schedule Page: 216 Line No.: 12 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.

Schedule Page: 216 Line No.: 18 Column: a

Jointly owned with Northwestern Energy, LLC, PP&L Montana, LLC, Puget Sound Energy, Inc., Pacific Corp, and Avista Corporation. Respondent's 20% share of 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 2014/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	3,299,660,915	3,299,660,915		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	241,730,943	241,730,943		
4	(403.1) Depreciation Expense for Asset Retirement Costs	3,569,396	3,569,396		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	4,203,928	4,203,928		
7	Other Clearing Accounts	261,352	261,352		
8	Other Accounts (Specify, details in footnote):				
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	249,765,619	249,765,619		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	37,027,074	37,027,074		
13	Cost of Removal	3,189,583	3,189,583		
14	Salvage (Credit)	1,458,969	1,458,969		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	38,757,688	38,757,688		
16	Other Debit or Cr. Items (Describe, details in footnote):	145,620,706	145,620,706		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	3,656,289,552	3,656,289,552		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	820,210,311	820,210,311		
21	Nuclear Production				
22	Hydraulic Production-Conventional	166,709,413	166,709,413		
23	Hydraulic Production-Pumped Storage				
24	Other Production	507,227,461	507,227,461		
25	Transmission	200,063,618	200,063,618		
26	Distribution	1,792,248,824	1,792,248,824		
27	Regional Transmission and Market Operation				
28	General	169,829,925	169,829,925		
29	TOTAL (Enter Total of lines 20 thru 28)	3,656,289,552	3,656,289,552		

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

In 1985, PGE sold a 15% undivided interest in the Boardman Plant and a 10.714% undivided interest in the Company's share of the Pacific Northwest Intertie transmission line (jointly, the Facility Assets) to an unrelated third party (Purchaser). Under the terms of the original 1985 agreements, on December 31, 2013, PGE acquired the Facility Assets from the Purchaser in exchange for $1 from the Purchaser. This transaction was approved by the FERC on December 19, 2013 through Docket EC14-13-000.

The original cost of the 15% of the Boardman Plant and the 10.714% undivided interest in the Company's share of the Pacific Northwest Intertie transmission line at December 31, 2013 was estimated at $96 million and $2 million, respectively. It was also estimated that these assets were fully depreciated at the time the acquisition was executed since it coincided with the expiration of various agreements under the terms of the original 1985 transaction.

The proposed final accounting entries associated with this transaction were submitted to the FERC on June 27, 2014, in compliance with the accounting under the Uniform System of Accounts (Docket AC14-129-000). On September 29, 2014, FERC approved the final proposed journal entries. In September 2014, the final accounting entries were executed, which increased both Electric plant in service (Account 101) and Accumulated provision for depreciation (Account 108) by $97,861,971 (Steam $94,061,144 and Transmission $3,800,827) with corresponding offsets to Electric plant purchased or sold (Account 102).

In December 2014 PGE acquired an additional 10% undivided interest from another co-owner in the Boardman Plant, and associated equipment and facilities, as well as certain contracts and other rights related to that co-owner's ownership interest in the Boardman Plant.

The original cost of the 10% share of the assets acquired at December 31, 2014 was estimated at $67 million.

On September 19, 2014, PGE filed an application requesting authorization for the acquisition of the rights, titles, and interests associated with this transaction pursuant to section 203(a)(1) of the Federal Power Act (FPA), including proposed accounting entries. On November 14, 2014, the FERC concluded that the proposed transaction was consistent with public interest and authorized the transaction (Docket EC14-147-000). In December 2014, accounting entries were executed which increased Electric plant in service (Account 101) by $67,211,321 (Steam Plant $65,882,727 and Transmission $1,328,594), Accumulated provision for depreciation (Account 108) by $47,707,066 (Steam $46,764,020 and Transmission $943,046), and Construction work in progress (Account 107) by $372,000 with corresponding offsets to Electric plant acquisition adjustments (Account 114).

In accordance with Electric Plant Instruction No. 5 of the Uniform System of Accounts and Electric plant purchased or sold (Account 102), PGE will submit final accounting entries within six months of the date that the proposed transaction was authorized by the FERC.

On January 8, 2014, PGE acquired a 104 kW solar photovoltaic generating facility from Sunway 1, LLC (Sunway). The generating facility and all equipment, materials, and funds relating to Sunway were acquired at net book value.

In accordance with the FERC regulations at 18 CFR Part 101, PGE recorded the acquisition in Electric plant purchased or sold (Account 102). In June 2014, in accordance with Electric plant instruction No. 5 as presented by the FERC, PGE requested approval of proposed journal entries to clear Account 102.

On December 5, 2014 the proposed final accounting entries were approved by the Commission (Docket AC14-119-000). In December 2014 the final entries were executed, which increased Electric plant in service (Account 101) by $42,650, Accumulated provision for depreciation (Account 108) by $42,650, and Construction work in progress account 107 by $181,467, with corresponding offsets to Electric plant purchased or sold (Account 102).

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 2014/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			89
9	Sub - TOTAL			10,089
10				
11	SunWay 1, LLC			
12	Paid in Capital	5/29/08		256,273
13	Dissolution			
14	Equity in Earnings			-72,577
15	Sub - TOTAL			183,696
16				
17	SunWay 2, LLC			
18	Paid in Capital	9/16/08		1,276,014
19	Equity in Earnings			-632
20	Sub - TOTAL			1,275,382
21				
22	SunWay 3, LLC			
23	Paid in Capital	10/19/09		2,415,395
24	Equity in Earnings			-868
25	Sub - TOTAL			2,414,527
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	4,060,819

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 2014/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

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

Equity in Subsidiary Earnings of Year (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
283,870	-275,000	8,959		8
283,870	-275,000	18,959		9
				10
				11
		256,273		12
		-183,695		13
-1		-72,578		14
-1				15
				16
				17
		1,276,014		18
-9		-641		19
-9		1,275,373		20
				21
				22
		2,415,395		23
-9		-877		24
-9		2,414,518		25
				26
				27
				28
				29
				30
				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
283,851	-275,000	3,885,975		42

Schedule Page: 224 Line No.: 15 Column: g

On January 8, 2014, PGE acquired the assets and liabilities of SunWay 1, LLC, a variable interest entity, at net book value. The entity was subsequently dissolved.

Schedule Page: 224 Line No.: 20 Column: g

Represents PGE's share of SunWay2, LLC a variable interest entity jointly owned by PGE (0.01% interest) and U.S. Bank (99.99% interest). SunWay 2, LLC was formed for the sole purpose of (1) Designing, developing, constructing, owning, maintaining, operating, and financing three photovoltaic solar power facilities located on the rooftops of three different buildings in Portland, Oregon, which are owned by ProLogis (a Maryland real estate investment trust), and (2) Selling the energy generated by the facilities.

<u>SunWay 2, LLC statistics at 12/31/2014 (100%)</u>

In-service Production cost: $5,922,280
Total installed capacity: 1.1 MW
Operations and Maintenance for 2014: $382,024

Schedule Page: 224 Line No.: 25 Column: g

Represents PGE's share of SunWay 3, LLC, a variable interest entity jointly owned by PGE (0.01% interest) and Firstar Development, LLC, a wholly-owned subsidiary of US bank, (99.99% interest). SunWay 3, LLC was formed for the sole purpose of (1) Designing, developing, constructing, owning, maintaining, operating, and financing seven photovoltaic solar power facilities located on the rooftops of seven different buildings in Portland, Oregon, which are owned by ProLogis (a Maryland real estate investment trust), and (2) Selling the energy generated by the facilities.

<u>SunWay 3, LLC statistics at 12/31/2014 (100%)</u>

In-service Production cost: $7,454,015
Total installed cappacity: 2.4 MW
Operations and Maintenance for 2014: $476,414

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 2014/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)	24,019,002	39,025,434	Generation
2	Fuel Stock Expenses Undistributed (Account 152)	1,402,813	3,333,157	Generation
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	11,372,887	11,206,292	Distribution
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	19,477,615	20,644,198	Generation
8	Transmission Plant (Estimated)	215,900	237,700	Transmission
9	Distribution Plant (Estimated)	3,439,418	3,574,388	Distribution
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	277,648	307,083	Power Operations
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	34,783,468	35,969,661	
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)	4,765,622	3,164,304	
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	64,970,905	81,492,556	

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

Allowances (Accounts 158.1 and 158.2)

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

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year		2015	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	29,376.00	113,328	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	6,922.00	113,328		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	22,454.00		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	1,153.06		144.78	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	144.78			
40	Balance-End of Year	1,008.28		144.78	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)		65		
45	Gains		65		
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 2014/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.

2016		2017		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
10,031.00		10,030.00		146,244.00		205,711.00	113,328	1
								2
								3
				2,640.00		2,640.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						6,922.00	113,328	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
10,031.00		10,030.00		148,884.00		201,429.00		29
								30
								31
								32
								33
								34
								35
144.78		144.78		4,037.38		5,624.78		36
				76.00		76.00		37
								38
				144.78		289.56		39
144.78		144.78		3,968.60		5,411.22		40
								41
								42
								43
					6		71	44
					6		71	45
								46

Allowances (Accounts 158.1 and 158.2)

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

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2015 No. (d)	2015 Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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.

2016		2017		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	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
								45
								46

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					

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21						
22	Abandoned Trojan Nuclear Plant					
23	Decommissioning Costs;	308,853,794	1,829,511	407,254	1,829,511	
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 # 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	308,853,794	1,829,511		1,829,511	

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) $(1,670,489) - Reclass balance of unrecovered plant and regulatory study costs related to Trojan to Account 254, Regulatory liability. In 2013 and 2014, $44,141,519 and $5,852,567, respectively, were deposited into the Nuclear decommissioning trust due to a settlement of a legal matter concerning costs associated with the operation of the Independent Spent Fuel Storage Installation (ISFSI), causing the balance to become a 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 2014/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					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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	Tax Benefits Related to Book/Tax Basis Differences	47,556,392	5,987,965			53,544,357
2	Previously Flowed to Customers	31,704,261	3,991,977			35,696,238
3	(Amort. period is based on the lives of the					
4	properties, approximately 25 years.)					
5						
6	Photovoltaic Volumetric Incentive Pilot	22,911	6,172,806	407.3	5,051,152	1,144,565
7	(per OPUC Order No. 10-198 dtd 5/28/2010)					
8	Reauthorized per Advice No.13-30 dtd 12/13/2013					
9	amortization period: 1/1/2014-12/31/2014					
10						
11	Colstrip Common Facilities (28 year amort. ending	1,073,807		407.3	322,140	751,667
12	2017, FERC OCA-AD ltr dtd 5/23/1989)					
13						
14	Price Risk Management	176,277,829	94,551,815	various	50,133,063	220,696,581
15						
16	Deferred Broker Settlement	13,328,075	2,328,529	555	12,047,445	3,609,159
17						
18	Intervenor Funding (original deferral per OPUC	467,515	355,369			822,884
19	Order No. 03-388 dtd 7/2/2003)					
20						
21	Independent Evaluator Deferral	40,786	46	various	40,832	
22	(per OPUC Order No. 08-010 dtd 1/14/2008)					
23	amortization per Advice No.12-19 dtd 12/18/2012					
24	amortization period: 1/1/2013-12/31/2013					
25						
26	Independent Evaluator Deferral (2011)	478,581	37,899			516,480
27	(per OPUC Order No. 11-154 dtd 5/10/2011)					
28						
29	Generation Plant Maintenance Deferral	3,422,460		557	684,492	2,737,968
30	(per OPUC Order no. 08-601 dtd 12/29/2008;					
31	amortization period: 1/1/2009 - 12/31/2018)					
32						
33	Stable Rate Revenue Balancing Acct	30,453	16,579	449.1	47,032	
34	(per Advice No 06-13 dtd 6/22/2006)					
35	amortization per Advice No.12-19 dtd 12/18/2012;					
36	amortization period: 1/1/2013-12/31/2013					
37						
38	Residential Sch 123 SNA Deferral-2012	1,386,166	31,790	456	1,417,956	
39	(reauthorized OPUC Order No. 12-061 dtd 2/28/2012)					
40	amortization per Advice No.13-06 dtd 5/31/2013;					
41	amortization period: 6/1/2013-5/31/2014					
42						
43	Residential Sch 123 SNA Deferral-2013	3,855,602	138,182	456	1,414,353	2,579,431
44	TOTAL	516,243,189	212,995,034		114,962,628	614,275,595

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 2014/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	(reauthorized OPUC Order No.13-30 dtd 12/13/2013)					
2	amortization period: 6/1/2014-12/31/2014					
3						
4	Residual Deferred Account	(242,775)	2,275	421	4,330	-244,830
5	(per OPUC Order No. 10-279 dtd 7/23/2010)					
6						
7	Glass Insulator Deferral	1,967,259	547,010	571	34,705	2,479,564
8	(per OPUC Order No. 10-478 dtd 12/17/2010;					
9	UE 215 First Revenue Requirement Stipulation)					
10						
11	Pension Funding	185,791,162	67,269,245	219/926	17,216,664	235,843,743
12	Postretirement Funding	8,099,642	3,980,735	219/926	1,317,492	10,762,885
13	(per SFAS No. 158 adopted 12/31/2006;					
14	OPUC Order No. 07-051 dtd 2/12/2007)					
15						
16	Boardman Decommissioning Balancing	253,005	180,748			433,753
17	(per Advice No. 11-07 dtd 05/27/2011)					
18						
19	UE 215 Four Capital Projects Deferral-2012 Vintage	14,685,707	1,062,525	407.3	15,978,357	-230,125
20	(per OPUC Order No. 10-478 dtd 12/17/2010,					
21	UE 215 Second Revenue Requirement Stipulation)					
22	Approved into amortization as part of UE 262					
23	(per OPUC Order No.13-459 dtd 12/09/2013)					
24	amortization period: 1/1/2014 - 12/31/2014					
25						
26	UE 215 Four Capital Projects Deferral-2013 Vintage	19,246,095	124,874	407.4	12,556	19,358,413
27	(per OPUC Order No. 10-478 dtd 12/17/2010,					
28	UE 215 Second Revenue Requirement Stipulation)					
29						
30	Baldock Revenue Requirement Deferral	7,919		182.3/421	7,919	
31	(per OPUC Order No. 12-063 dtd 2/28/2012)					
32	Amortization per Docket No.UE 249					
33	OPUC Advice No.12-09 dtd 12/18/2012					
34	Amortization period 01/01/2013-12/31/2013					
35						
36	Environmental Remediation Deferral	3,100,000				3,100,000
37						
38	Automated Demand Response Cost Recovery Mechanism	175,408	675,684	various	733,592	117,500
39	(per OPUC order No 13-059 dtd 2/26/2013					
40	Amortization per Advice No 13-04 dtd 3/8/2013					
41	Amortization period 01/01/2014-12/31/2014					
42						
43	2012 Lost Revenue Recovery Adjustment (LRRA)	303,614	1,167	242/256	304,781	
44	TOTAL	516,243,189	212,995,034		114,962,628	614,275,595

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	(reauthorized OPUC Order No.12-061 dtde 2/28/2012;)					
2	amortization per Advice No.13-06 dtd 5/31/2013					
3	Amortization period 6/1/2013-5/31/2014					
4						
5	2013 Lost Revenue Recovery Adjustment (LRRA)	2,586,359	1,537,649	456	254,979	3,869,029
6	(reauthorized OPUC Order No.13-044 dtd 2/12/2013)					
7	Amortization period 6/1/2014-05/31/2015					
8						
9	Direct Access Open Enrollment Deferral -2013	624,956	6,517	447	568,209	63,264
10	(per OPUC Docket UE 246					
11	Advice No.12-09 dtd 12/18/2012)					
12	Amortization period 1/1/2014-12/31/2014					
13						
14	IT O&M 2014 Deferral		8,684,000	various	1,736,800	6,947,200
15	(per OPUC GRC Order No.13-459, dtd 12/9/2013					
16	S-9 Partial Stipulation)					
17	Amortization period 1/1/2014-12/31/2018					
18						
19	CET 2014 Deferral		7,497,007	903	1,600,000	5,897,007
20	(per OPUC GRC Order No.13-459, dtd 12/9/2013					
21	S-7 Partial Stipulation)					
22	Amortization period 1/1/2014-12/31/2018					
23						
24	Tucannon RAC Deferral		1,439,747			1,439,747
25	(per OPUC GRC UE-283 Order No.14-422, dtd 12/4/14					
26	and Advice No.14-06, dtd 3/31/2014)					
27						
28	Port Westward Major Maintenance Accrual		6,372,894	553	4,033,779	2,339,115
29	(per OPUC GRC Order No.13-459, dtd 12/9/2013)					
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	516,243,189	212,995,034		114,962,628	614,275,595

Schedule Page: 232 Line No.: 14 Column: d

Amounts charged to accounts 555, 547 and 219.

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

Current year reauthorizaion approved through OPUC Orders:
$8,333 Order 14-011 dated 01/09/2014, docket UM-1633
$66,125 Order 14-008 dated 01/09/2014, docket UM-1357(47)
$8,304 Order 14-143 dated 05/21/2014, docket UM-1633
$1,100 Order 14-140 dated 04/29/2014, docket UM-1616
$4,296 Order 14-120 dated 04/10/2014, docket UE-262
$31,055 Order 13-455 dated 12/02/2013, docket UE-262
$60,000 Order 13-290 dated 08/06/2013, docket UE-262
$8,333 Order 14-172 dated 05/21/2014, docket UM-1633
$10,493 Order 14-136 dated 06/19/2014, docket UM-1357(47)
$67,212 Order 14-307 dated 09/03/2014, docket UE-283
$28,981 Order 14-309 dated 09/03/2014, docket UE-286
$10,926 Order 14-329 dated 09/26/2014, docket UE-286
$5,925 Order 14-328 dated 09/26/2014, docket UM-1679
$67,462 Order 14-362 dated 10/24/2014, docket UE-283
$3,225 Order 14-411 dated 11/20/2014, docket UM-1690
$15,289 Order 14-407 dated 11/20/2014, docket LC-56
$1,257 Order 14-418 dated 12/03/2014, docket UE-286
The Intervenor CUB fund was reduced by $(46,998) and the Intervenor Issue fund by $(7,651) per agreement with OPUC (Advice No.14-15, dated 12.16.2014. Item No.CA-9 on consent agenda for public meeting on 12.16.2014) to refund uncollectible renewables program premiums as one time retroactive adjustment.
$11,702 was interest accrued in 2014.

Schedule Page: 232 Line No.: 21 Column: d

Accounts debited include: 182.3 "Residual Deferred Account" and 407.3

Schedule Page: 232 Line No.: 21 Column: e

The residual debit balance of $21,264, remaining after the authorized amortization period, was transferred to the Residual Deferred Account, pursuant to PUC Order No.10-279 dated July 23, 2010.

Schedule Page: 232 Line No.: 33 Column: c

The residual credit balance of $16,570 remaining after the authorized amortization period, was transferred to the Residual Deferred Account, pursuant to OPUC Order No.10-279 dated July 23, 2010. $9 interest accrued in 2014.

Schedule Page: 232 Line No.: 33 Column: e

Amount of $47,032 represents remaining amortization for the 01/01/2013-12/31/2013 approved amortization period.

Schedule Page: 232.1 Line No.: 4 Column: c

The residual balance remaining after the authorized amortization period, was transferred to the Residual Deferred account pursuant to OPUC Order No. 10-279.
The following accounts were reclassed:
- account 182.3 "Baldock Solar - Revenue Requirements" in amount of $7,597;
- account 254 "Baldock Solar - Gain on Sale" in amount of $(2,804);
- account 242 "2011 PCAM" in amount of $(12,387);
- account 254 "2012 DA Open Enrollment" in amount of $4,743;
- account 182.3 "Independent Evaluator Deferral" in amount of $21,264;
- account 182.3 "Stable Rate Pilot Sch.07" in amount of $(16,570);
- account 242 "Stable Rate Pilot Sch.32" in amount of $432.

Schedule Page: 232.1 Line No.: 30 Column: e

The residual balance of $7,597, remaining after the authorized amortization period, was transferred to the Residual Deferred Account pursuant to OPUC Order No.10-279.
An accrued interest of $322 was charged to account 421.

Schedule Page: 232.1 Line No.: 38 Column: d

Amounts charged to accounts 431, 456, 555 and 908.

Schedule Page: 232.2 Line No.: 14 Column: d

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

Schedule Page: 232.2 Line No.: 24 Column: c

Renewable Resource Automatic Adjustment Clause (RRAAC) deferral related to the Tucannon Wind Farm going on-line on December 15, 2014, but Base Rates not being adjusted until January 01, 2015.

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 2014/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	247,656	126,340	various	573,345	-199,349
3						
4	Net Co-owner / Trust Contributi	1,807,975	142,369,542	various	144,060,514	117,003
5						
6	Deferred Rent - WTC Tenant					
7	amort. through 2021	927,537	38,679	418	139,441	826,775
8						
9	Deferred Revolving Credit					
10	Agreement Fees					
11	amort. through 2018	2,381,559	2,297,040	431	2,968,394	1,710,205
12						
13	Dispatchable Generation					
14	various amort. periods from					
15	2005 and extending through 2024	7,823,366	2,504,520	903	1,185,474	9,142,412
16						
17	LID Receivable from WTC Tenants					
18	amort. over 20 yrs through 2029	95,828		418	5,989	89,839
19						
20	Colstrip - Lime Contract					
21	amort. over 4 yrs. 2011 - 2014	600,000		various	600,000	
22						
23	Utility Property Sales-					
24	Selling Expenses	2,373,010	17,767	254	2,373,010	17,767
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46						
47	Misc. Work in Progress	294,238				72,155
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	16,551,169				11,776,807

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 2014/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	1,094,274	-10,738,741
3	Regulatory Liabilities	16,086,599	47,454,122
4	Employee Benefits	123,234,494	160,994,463
5	Price Risk Management	76,241,972	91,209,388
6	Tax Credits & NOL's	50,888,594	13,236,327
7	Other	32,979,191	17,462,242
8	TOTAL Electric (Enter Total of lines 2 thru 7)	300,525,124	319,617,801
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)	4,481,514	4,525,075
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	305,006,638	324,142,876

Notes

Line 7 - Other

	Ending Bal 12/31/2013	Ending Bal 12/31/2014
Bad Debt Expense	$2,346,104	$2,563,595
Nuclear Decommissioning Trust	20,233,197	3,977,456
Renewable Energy Development	6,075,684	6,068,920
Miscellaneous	4,324,206	4,852,271
Total Line 7 - Other	$32,979,191	$17,462,242

Line 17 - Other Non Utility	Ending Bal 12/31/2013	Ending Bal 12/31/2014
Property Related	$4,032,008	$4,245,847
Employee Benefits	449,506	279,228
Total Line 17 - Other Non Utility	$4,481,514	$4,525,075

Schedule Page: 234 Line No.: 1 Column:

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 2014/Q4

CAPITAL STOCKS (Account 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Series (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 Account 201:	160,000,000		
5				
6	Account 204:			
7	No Par Value Cumulative Preferred	30,000,000		
8				
9	Total Account 204:	30,000,000		
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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
78,228,339	911,154,338					2
						3
78,228,339	911,154,338					4
						5
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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	
3	compensation and associated income tax benefits	4,804,482
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	2,578,827
18	Reacquired common stock	-68,327
19	Former parent assumption of PGE tax liabilities on Non-Qualified Plan	610,028
20	Oregon tax credit related to PGE's separation from former parent	8,317,516
21	SUBTOTAL Account 211	11,432,576
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40	TOTAL	17,842,676

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 2014/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	10,832,643
2		
3		
4		
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22	TOTAL	10,832,643

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			
15	6.80% Series Due 1/15/2016 - Order No. 08-106 01/28/2008	67,000,000	456,731
16	6.10% Series Due 4/15/2019 - Order No. 09-089 03/16/2009	300,000,000	2,386,224
17			222,000 D
18	5.43% Series Due 5/3/2040 - Order No. 09-245 06/22/2009	150,000,000	1,034,284
19	3.46% Series Due 1/14/2015 - Order No. 09-405 10/08/2009	70,000,000	455,869
20	3.81% Series Due 6/15/2017 - Order No. 09-405 10/08/2009	58,000,000	375,096
21	4.47% Series Due 6/15/2044 - Order No. 13-098 03/26/2013	150,000,000	1,113,047
22	4.47% Series Due 8/14/2043 - Order No. 13-098 03/26/2013	75,000,000	558,740
23	4.84% Series Due 12/15/2048 - Order No. 13-098 03/26/2013	50,000,000	652,029
24	4.74% Series Due 11/15/2042 - Order No. 13-098 03/26/2013	105,000,000	311,154
25			
26	4.39% Series Due 8/15/2045 - Order No. 14-145 04/29/2014	100,000,000	645,383
27	4.44% Series Due 10/15/2046 - Order No. 14-145 04/29/2014	100,000,000	625,030
28	3.51% Series Due 11/15/2024 - Order No. 14-145 04/29/2014	80,000,000	501,502
29			
30	Pollution Control Bonds (Guaranteed by Company) -		
31	Port of Morrow, OR Series 1998A 5% Due 5/1/2033	23,600,000	604,452
32	City of Forsyth, MT Series 1998A 5% Due 5/1/2033	97,800,000	2,615,167
33	TOTAL	2,501,495,828	20,056,750

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 2014/Q4

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1			
2	SUBTOTAL ACCOUNT 221	2,196,400,000	20,011,758
3			
4	ACCOUNT 224 - OTHER LONG TERM DEBT		
5	Variable Interest Due - Libor + 70 basis pts Due 10/30/2015 - Order 14-145 04/29/14	75,000,000	11,248
6	Variable Interest Due - Libor + 70 basis pts Due 10/30/2015 - Order 14-145 04/29/14	75,000,000	11,248
7	Variable Interest Due - Libor + 70 basis pts Due 10/30/2015 - Order 14-145 04/29/14	75,000,000	11,248
8	Variable Interest Due - Libor + 70 basis pts Due 10/30/2015 - Order 14-145 04/29/14	80,000,000	11,248
9	City of Portland Improvement District Loan	95,828	
10	SUBTOTAL ACCOUNT 224	305,095,828	44,992
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32			
33	TOTAL	2,501,495,828	20,056,750

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 2014/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)	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	75,000,000	4,350,000	13
						14
01/15/2009	01/15/2016	01/15/2009	01/15/2016	67,000,000	4,556,000	15
04/16/2009	04/15/2019	04/16/2009	04/15/2019	300,000,000	18,300,000	16
						17
11/30/2009	05/03/2040	11/30/2009	05/03/2040	150,000,000	8,145,000	18
01/15/2010	01/14/2015	01/15/2010	01/14/2015	70,000,000	2,428,239	19
06/15/2010	06/15/2017	06/15/2010	06/15/2017	58,000,000	2,209,800	20
6/27/2013	6/15/2044	6/27/2013	6/15/2044	150,000,000	6,705,000	21
8/29/2013	8/14/2043	8/29/2013	8/14/2043	75,000,000	3,352,500	22
12/16/2013	12/15/2048	12/16/2013	12/15/2048	50,000,000	2,420,000	23
11/15/2013	11/15/2042	11/15/2013	11/15/2042	105,000,000	4,977,000	24
						25
8/15/2014	8/15/2045	8/15/2014	8/15/2045	100,000,000	1,658,439	26
10/15/2014	10/15/2046	10/15/2014	10/15/2046	100,000,000	937,333	27
11/17/2014	11/15/2024	11/17/2014	11/15/2024	80,000,000	343,200	28
						29
						30
05/28/1998	05/01/2033	05/28/1998	05/01/2033	23,600,000	1,180,000	31
05/28/1998	05/01/2033	05/28/1998	05/01/2033	97,800,000	4,890,000	32
				2,501,489,838	111,306,270	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 2014/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
				2,196,400,000	109,842,511	2
						3
						4
5/12/2014	10/30/2015	05/12/2014	10/30/2015	75,000,000	423,905	5
05/31/2014	10/30/2015	05/31/2014	10/30/2015	75,000,000	407,438	6
06/30/2014	10/30/2015	06/30/2014	10/30/2015	75,000,000	324,789	7
07/21/2014	10/30/2015	07/21/2014	10/30/2015	80,000,000	307,627	8
11/16/2009	11/16/2029			89,838		9
				305,089,838	1,463,759	10
						11
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						31
						32
				2,501,489,838	111,306,270	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 2014/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)	175,401,893
2		
3		
4	Taxable Income Not Reported on Books	
5	Depreciation, Depletion & Amortization	18,839,580
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Price Risk Management and Mark-to-Market	44,418,751
11	Regulatory Credits	30,548,721
12	Other (See Footnote)	92,561,913
13		
14	Income Recorded on Books Not Included in Return	
15	Depreciation, Depletion & Amortization	-59,020,120
16	Regulatory Debits	-17,008,736
17	Other (See Footnote)	-470,001
18		
19	Deductions on Return Not Charged Against Book Income	
20	Depreciation, Depletion & Amortization	-70,528,357
21	State & Local Tax Deduction	-1,430,167
22	Other (See Footnote)	-6,331,621
23		
24		
25		
26		
27	Federal Tax Net Income	206,981,856
28	Show Computation of Tax:	
29	Normal Federal Current Provision Benefit @35%	72,443,651
30	Federal Energy Tax Credit	-55,096,916
31	RTA and FAS 109 Adjustment	623,117
32	APIC Tax Adjustment	2,053,195
33	Total Federal Income Tax - PGE	20,023,047
34		
35		
36		
37		
38		
39		
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41		
42		
43		
44		

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

Qualified Nuclear Decommissioning Trust	$9,364,734
Meals & Entertainment	709,642
Politcal Activity	851,607
Bad Debts	543,727
Employee Benefits	13,858,098
Federal Tax Expense	46,202,730
Contingent Royalty Payments	806,123
Obsolete Inventory	660,040
Unamortized loss on Reacquired Debt	1,585,063
Stock Incentive Plans	2,219,243
State Tax Expense	14,873,833
Miscellaneous	887,073
Total Other	92,561,913

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

Key Man Insurance Proceeds	(137,891)
Miscellaneous	(332,110)
Total Other	($470,001)

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

Dividends Received Deduction	($45,000)
IRC Sec 199 Domestic Production Activities Deduction	(1,758,221)
Environmental Remediation	(54,619)
Renewable Energy Initiatives	(2,062,291)
Utility Land Sale	(1,471,630)
Property Tax	(892,651)
Miscellaneous	(47,209)
Total Other	($6,331,621)

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 2014/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	125,001		531,980	531,980	
3	Income Tax		845,805	18,835,903	20,000,000	180,574
4	Foreign Insurance Excise Tax					
5	FICA (Employer Share)	1,375,092		18,988,990	18,537,547	
6	Unemployment	2,491		121,200	126,259	
7	Power License	636,866		2,001,718	1,844,923	
8	Superfund Tax					
9	SUBTOTAL Federal	2,139,450	845,805	40,479,791	41,040,709	180,574
10	State of Montana:					
11	Income Tax		39,695	466,634	442,692	
12	Elec. Energy Producers Tax	187,200		555,910	565,110	
13	Property Taxes	2,578,897		5,464,116	5,313,845	
14	SUBTOTAL Montana	2,766,097	39,695	6,486,660	6,321,647	
15	State of Oregon:					
16	Corp Excise Tax		519,186	-12,536	-99,550	42,435
17	Property Taxes		23,414,592	47,852,944	48,664,138	
18	City Taxes and Licenses	3,386,550		41,634,097	41,489,724	
19	Public Utility Comm Fees			4,613,542	4,613,542	
20	Department of Energy		686,883	1,368,136	1,362,501	
21	Department of Enviro Quality	446,195		45,231	31,422	
22	Unemployment	73,360		2,106,982	2,126,242	
23	Water Power Fee		552,197	551,702	935,557	
24	Transportation Tax	331,922		1,393,583	1,364,459	
25	Workers Comp Assessment	57,764		246,511	246,511	
26	County & City Income Tax		-72,407	1,113,168	1,250,400	21,152
27	SUBTOTAL Oregon	4,295,791	25,100,451	100,913,360	101,984,946	63,587
28	State of Washington:					
29	Property Taxes	38,484		446,672	65,400	
30	Sales Tax					
31	SUBTOTAL Washington	38,484		446,672	65,400	
32	State of Wyoming:					
33	Sales Tax					
34	SUBTOTAL Wyoming					
35	State of California:					
36	Corporate franchise tax		400,000	142,641	300,000	
37	SUBTOTAL California		400,000	142,641	300,000	
38	Canada:					
39	Goods & Services Tax					
40	SUBTOTAL Canada					
41	TOTAL	9,239,822	26,385,951	148,469,124	149,712,702	244,161

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 2014/Q4

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 (I) 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
125,001					531,980	2
	1,829,328	20,555,463			-1,719,560	3
		19,184			-19,184	4
1,826,535		11,294,979			7,694,011	5
-2,568		71,978			49,222	6
555,683	-237,978				2,001,718	7
						8
2,504,651	1,591,350	31,941,604			8,538,187	9
						10
	15,753	485,248			-18,614	11
178,000		327,767			228,143	12
2,729,168		4,507,881			956,235	13
2,907,168	15,753	5,320,896			1,165,764	14
						15
	389,737	347,245			-359,781	16
	24,225,786	45,345,335			2,507,609	17
3,530,923		41,634,095			-3	18
					4,613,542	19
	681,248	1,368,136				20
460,004					45,231	21
54,100		1,251,299			855,683	22
	936,052				551,702	23
361,046		827,624			565,959	24
57,764		146,398			100,113	25
	43,673	1,143,450			-30,282	26
4,463,837	26,276,496	92,063,582			8,849,773	27
						28
419,756		51,839			394,833	29
						30
419,756		51,839			394,833	31
						32
						33
						34
						35
	557,359	142,641				36
	557,359	142,641				37
						38
						39
						40
10,295,412	28,440,958	129,520,562			18,948,557	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	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 2014/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%						
6							
7							
8	TOTAL						
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
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16							
17							
18							
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48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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
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			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 2014/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	Accelerated cost recovery system	751,000				751,000
2	tax benefit sale - amort. over					
3	service lives of related					
4	property					
5						
6	Tenant sub-lease security deposits	44,402	232	3,065		41,337
7						
8	Deferred Liability for Transferred	743,115	421	45,045		698,070
9	Non-Qualified Plan Benefits					
10						
11	Carty Retainage for EPC Contract	6,370,515	107/232	6,370,515		
12						
13	Environmental Remediation Deferral	3,100,000	232	1,550,000		1,550,000
14						
15	TID PPA prepaid coal stock				2,134,000	2,134,000
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
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36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	11,009,032		7,968,625	2,134,000	5,174,407

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

Total amount of $6,370,515 consists of:
- $1,820,147 - reversed Carty retainage (offset by account 107);
- $4,550,368 - reclassed Carty retainage to short-term account 232.

Schedule Page: 269 Line No.: 13 Column: d

Reclassed current portion of accrual for Downtown Reach clean-up to account 232.

Schedule Page: 269 Line No.: 15 Column: e

Deferred liability associated with the acquisition of coal stock inventory from Power Resources Cooperative during PGE's acquisition of PRC's 10% interest in Boardman plant (Turlock Irrigation District Power Purchase Agreement).

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 2014/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	Balance at Beginning of Year	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1	Amounts Credited to Account 411.1
	(a)	(b)	(c)	(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				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	(k)	
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
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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 2014/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	619,065,292	90,800,636	64,933,934
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	619,065,292	90,800,636	64,933,934
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	619,065,292	90,800,636	64,933,934
10	Classification of TOTAL			
11	Federal Income Tax	506,566,013	72,645,617	52,457,917
12	State Income Tax	104,139,799	16,795,417	11,541,471
13	Local Income Tax	8,359,480	1,359,602	934,546

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
		182.3	24,295,111	254	30,283,076	650,919,959	2
							3
							4
			24,295,111		30,283,076	650,919,959	5
							6
							7
							8
			24,295,111		30,283,076	650,919,959	9
							10
			20,207,148		24,997,234	531,543,799	11
			3,777,772		4,890,663	110,506,636	12
			310,191		395,179	8,869,524	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 2014/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)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Property Related	31,705,742		
4	Price Risk Management	5,730,839		2,800,084
5	Regulatory Assets	174,416,473	68,508,685	33,624,313
6	Regulatory Liabilities			
7	Other	15,729,354	946,036	1,222,677
8				
9	TOTAL Electric (Total of lines 3 thru 8)	227,582,408	69,454,721	37,647,074
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other	2,849,190		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	230,431,598	69,454,721	37,647,074
20	Classification of TOTAL			
21	Federal Income Tax	186,117,748	56,098,045	30,407,253
22	State Income Tax	40,993,800	12,355,998	6,697,416
23	Local Income Tax	3,320,049	1,000,678	542,405

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						
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits Account Credited (g)	Debits Amount (h)	Credits Account Debited (i)	Credits Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
		254	16,176,168	182.3	20,166,689	35,696,263	3
						2,930,755	4
						209,300,845	5
							6
						15,452,713	7
							8
			16,176,168		20,166,689	263,380,576	9
							10
							11
							12
							13
							14
							15
							16
							17
789,262	1,799,103	236	129	236	1,583	1,840,803	18
789,262	1,799,103		16,176,297		20,168,272	265,221,379	19
							20
637,437	1,452,737		13,453,603		16,677,892	214,217,529	21
140,454	320,445		2,521,099		3,231,271	47,182,563	22
11,371	25,921		201,594		259,109	3,821,287	23

NOTES (Continued)

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

	Balance at Beginning of Year	Balance at End of Year
ASC 980 Mark-to-Market	55,931,456	48,599,462
Price Risk Mgmt Deferral	14,579,675	39,679,171
ASC 715 Pension & Post Retirement	77,556,321	98,642,651
Regulatory Deferral Earn Test Offset	12,989,164	6,427,842
Miscellaneous	13,359,857	15,951,719
Total Other	$174,416,473	$209,300,845

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

	Balance at Beginning of Year	Balance at End of Year
Unamortized Loss on Reacquired Debt	$ 6,711,798	$ 6,077,773
Prepaid Property Tax	9,077,739	9,435,123
Other	(60,183)	(60,183)
Total Other	$ 15,729,354	$ 15,452,713

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

	Balance at Beginning of Year	Balance at End of Year
Trust-Owned Life Insurance Gain/Loss	$ 1,977,911	$ 671,747
Reg Deferral Earn Test Offset	583,557	1,223,473
Other	287,721	(54,417)
Total Other	$ 2,849,189	$ 1,840,803

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	3,505,692	190	233,780		3,271,912
2						
3	Surplus CAA Allowances	672,916	254/431	672,966	50	
4	(per OPUC Order No. 552 dtd 3/31/1993)					
5						
6	BPA Subscription Power - Balancing Account	6,613,234	456	64,814,600	57,963,366	-238,000
7	(per OPUC Order No. 08-175 dtd 3/20/2008)	361,034	456	596,260	235,226	
8						
9	Gain on Asset Sales	4,438,542			3,426,860	7,865,402
10	(per OPUC Order No. 01-777 dtd 8/31/2001)					
11						
12	Gain on TRC Sales	1,918,002			34,225	1,952,227
13	(per OPUC Order No. 07-083 dtd 3/5/2007)					
14						
15	Boardman Severance	1,499,105			787,416	2,286,521
16	Advice No.14-18, dtd 11/3/2014					
17						
18	Asset Retirement Obligations:	37,436,649	407.3	1,709,662	2,865,251	38,592,238
19	Balancing Account					
20						
21	Coyote Springs Major Maintenance Deferral	2,415,114			1,232,802	3,647,916
22	(per OPUC Order No. 01-777 dtd 8/31/2001;					
23	reauthorization OPUC Order No. 10-478					
24	dtd 12/17/2010)					
25						
26	ISFSI Pollution Control Tax Credit Deferral	8,567,795		1,025,152	125,951	7,668,594
27	(per OPUC Order No. 05-136 dtd 3/15/2005)					
28						
29	Zero Interest Program Loan Repayments	1,569,852			272,421	1,842,273
30	(per Advice No. 05-19 dtd 12/20/2005)					
31						
32	Schedule 110 Energy Efficiency - Balancing Accout	182,034			118,084	300,118
33	(per Advice No. 07-25 dtd 5/20/2008)					
34						
35	Direct Access Open Enrollment - 2012	26,212	447	30,968	4,756	
36	(per Advice 11-31 dtd 11/15/2011)					
37	amortization per Advice 12-19 dtd 12/18/2012;					
38	amortization period: 01/01/2013-12/31/2013)					
39						
40	Sunway 3 Investment Deferral	750,310	407.4	45,480		704,830
41	TOTAL	111,443,593		70,078,203	86,184,241	127,549,631

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 2014/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	(per UM 1480 dtd 4/01/2010;					
2	amortization over 20 years)					
3						
4	Baldock Solar - Gain on Sale	2,804	182.3	2,804		
5	(per OPUC Order No. 12-063 dtd 2/28/2012)					
6	amortization per Advice 12-09 dtd 12/18/2012;					
7	amortization period: 01/01/2013-12/31/2013)					
8						
9	Multnomah County Business Income Tax Balancing	22,569	407.4/242	946,531	923,962	
10	(per Advice No. 11-27 dtd 10/27/2012;					
11	Schedule 6; OAR 860-022-0045)					
12						
13	Direct Access Open Enrollment - 2014				532,815	532,815
14	(per Advice 13-25 dtd 11/15/2013)					
15						
16	Trojan Decommissioning Deferral	41,461,729			7,523,056	48,984,785
17						
18	PRC Acquisition				10,138,000	10,138,000
19	(per OPUC UE-283 Final GRC Order No.14-422,					
20	dated 12/04/2014, and Second Partial					
21	Stipulation dated 09/02/2014)					
22						
23						
24						
25						
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27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	111,443,593		70,078,203	86,184,241	127,549,631

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

Reclassed CAA Allowances along with interest to "Gain on Asset Sales" account 2540003.

Schedule Page: 278 Line No.: 6 Column: d

Debit consists of pass through credits to customers in their billing statements.

Schedule Page: 278 Line No.: 6 Column: e

Credit consists of payments received from Bonneville Power Administration to be credited to customers pursuant to the Residential Exchange Program.

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

The total change on account consists of the following transactions:
- $1,788,031 - reclass of the Bull Run property sales deferral from account 229 to account 254 (authorized by OPUC Order No.11-424 dtd. 10/26/2011;
- $67,833 - reclass of net gain for the Bull Run spillway sale to Western Rivers from account 186;
- $339,929 - reclass of Lone Fir substation land sale from account 186;
- $62,432 - reclass of payment from Portland Service Center from account 107;
- $(286,115) - reclass of gain/loss from the sale of the Portland Service center property to Tri-Met;
- $354,709 - reclass of gain on sale of substation property from account 186;
- $672,966 - reclass of the "Surplus CAA Allowances" from account 254;
- $427,075 in accrued interest, including $313,170 of intrest accrued on the CAA Allowances.

Schedule Page: 278 Line No.: 15 Column: b

Previously recorded as part of Asset Retirement Obligations.

Schedule Page: 278 Line No.: 26 Column: d

Payments to co-owners for their share of the Trojan Spent Fuel settlement:
-$946,294 to Eugene Water and Electric Board;
-$78,858 to Pacificorp.

Schedule Page: 278 Line No.: 35 Column: e

Residual balance of $4,743, remaining after the authorized amortization period, was transferred to the Residual Deferrred Account 182.3 pursuant to OPUC Order No.10-279 dated 07/23/2010.

Schedule Page: 278.1 Line No.: 4 Column: d

Residual balance of $2,804, remaining after the authorized amortization period, was transferred to the Residual Deferred account 182.3 pursuant to OPUC Order No.10-279 dated 07/23/2010.

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

Includes deferral of $800,000 to account 407.4, and reclass of $146,531 to account 242.

Schedule Page: 278.1 Line No.: 16 Column: e

Includes $5,852,567 of proceeds received from Trojan Spent Fuel legal settlement.

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 2014/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	848,594,155	805,593,907
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	633,949,689	592,028,129
5	Large (or Ind.) (See Instr. 4)	221,298,764	206,820,494
6	(444) Public Street and Highway Lighting	17,151,203	17,532,792
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,720,993,811	1,621,975,322
11	(447) Sales for Resale	130,021,814	119,051,973
12	TOTAL Sales of Electricity	1,851,015,625	1,741,027,295
13	(Less) (449.1) Provision for Rate Refunds	3,398,715	-3,676,424
14	TOTAL Revenues Net of Prov. for Refunds	1,847,616,910	1,744,703,719
15	Other Operating Revenues		
16	(450) Forfeited Discounts	3,092,995	2,758,129
17	(451) Miscellaneous Service Revenues	1,716,285	1,855,439
18	(453) Sales of Water and Water Power	-27,627	14,457
19	(454) Rent from Electric Property	7,483,167	6,875,612
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	58,669,708	81,520,491
22	(456.1) Revenues from Transmission of Electricity of Others	8,027,230	7,689,044
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	78,961,758	100,713,172
27	TOTAL Electric Operating Revenues	1,926,578,668	1,845,416,891

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
7,461,863	7,701,768	735,502	728,481	2
				3
6,833,605	6,787,898	105,020	104,131	4
3,210,619	3,075,442	260	263	5
97,100	108,339	211	254	6
				7
				8
				9
17,603,187	17,673,447	840,993	833,129	10
3,476,895	3,553,416	40	41	11
21,080,082	21,226,863	841,033	833,170	12
				13
21,080,082	21,226,863	841,033	833,170	14

Line 12, column (b) includes $ 9,190,000 of unbilled revenues.

Line 12, column (d) includes 132,636 MWH relating to unbilled revenues

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

Includes $15,353,434 in revenue related to the delivery of 563,403 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 2014, the "transition adjustment" credits provided to many commercial and industrial customers were less than the charges for delivering the energy they purchased from ESSs. Since this energy was not sold by PGE, the associated megawatt hours are not reported on Page 301 column(d).

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

Includes $17,407,338 in revenue related to the delivery of 544,768 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 2013, the "transition adjustment" credits provided to many commercial and industrial customers were less than the charges for delivering the energy they purchased from ESSs. Since this energy was not sold by PGE, the associated megawatt hours are not reported on Page 301 column (d).

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

Includes $18,178,625 in revenue related to the delivery of 1,099,271 megawatt hours to customers of Energy Services Suppliers (ESSs). For 2014, the "transition adjustment" credits provided to many commercial and industrial customers were less than the charges for delivering the energy they purchased from ESSs. Since this energy was not sold by PGE, the associated megawatt hours are not reported on Page 301 column(d).

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

Includes $21,862,457 in revenue related to the delivery of 1,065,710 megawatt hours to customers of Energy Services Suppliers (ESSs). For 2013, the "transition adjustment" credits provided to many commercial and industrial customers were less than the charges for delivering the energy they purchased from ESSs. Since this energy was not sold by PGE, the associated megawatt hours are not reported on Page 301 column (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:

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.: 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

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

Other Electric Revenues consist of the following:

	2014
BPA Subscription Power - Balancing Account	49,803,095
BPA ER Wind Curtail Settled - RECS	349,841
Coyote Springs Major Maintenance	(1,232,803)
Tucannon RAC Deferral	1,437,457
Residential Sch 123 SNA Deferral	(2,953,685)
Sch 123 LRRA Deferral	894,039
Boardman Decommissioning Balancing Account	(614,251)
EE Program Delivery Contractor Services	2,187,169
PGE Share of Boardman Ash Sales	171,892
Large Generator Interconnection Process	(5,793)
Automated Demand Response Deferred Costs	(3,205,145)
Park Revenues	602,419
Steam Sales	2,494,638
Gas for Resale	(2,577,025)
Oil for Resale	807,873
Wheeling Resale	9,228,472
Other - net	1,281,512
Totals	$ 58,669,708

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

Other Electric Revenues consist of the following:

	2013
BPA Subscription Power - Balancing Account	$ 58,533,455
Biglow Canyon Phase 3 Deferral	(58,371)
Residential Sch 123 SNA Deferral	2,739,997
Sch 123 LRRA Deferral	3,238,746
Baldock Solar	1,790,798
Boardman Decommissioning Balancing Account	(716,005)
EE Program Delivery Contractor Services	1,881,563
PGE Share of Boardman Ash Sales	291,669
Large Generator Interconnection Process	265,009
Park Revenues	530,566
Steam Sales	2,004,226
Gas for Resale	3,574,536
Oil for Resale	2,502,608
Wheeling Resale	4,508,627
Other - net	433,067
Totals	$ 81,520,491

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 2014/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					
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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 2014/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	7 Residential Service	7,552,691	854,204,599	735,502	10,269	0.1131
3	15 Outdoor Area Lighting	5,066	1,380,556			0.2725
4	Residential Unbilled Revenue	-95,893	-6,991,000			0.0729
5	TOTAL Account 440	7,461,864	848,594,155	735,502	10,145	0.1137
6	General Comm. and Ind. Sales:					
7	15 Comm. Outdoor Lighting	14,749	2,897,121			0.1964
8	32 Small Nonresidential	1,592,536	169,333,805	88,824	17,929	0.1063
9	38 Optional Time of Day -	33,180	4,246,709	316	105,000	0.1280
10	Large Nonresidential					
11	47 Irrigation - Drainage - Small	19,530	3,019,366	2,010	9,716	0.1546
12	49 Irrigation - Drainage - Large	60,159	6,522,654	1,028	58,520	0.1084
13	83-S Large Nonresidential	2,782,757	246,651,548	11,175	249,016	0.0886
14	85-S Large Nonresidential	2,363,367	187,139,706	1,276	1,852,168	0.0792
15	89-S Large Nonresidential	6,561	486,346	1	6,561,000	0.0741
16	485-S COS Opt-Out - Lrg. Nonresid		9,969,528	159		
17	489-S COS Opt-Out - Lrg. Nonresid		589,120	1		
18	515-S DAS - Outdoor Area Lighting		9,183			
19	532-S DAS - Small Nonresidential		221,681	81		
20	583-S DAS - Large Nonresidential		1,722,254	104		
21	585-S DAS - Large Nonresidential		3,023,668	39		
22	Gen Comm. & Ind. Unbilled Revenue	-39,235	-1,883,000			0.0480
23	TOTAL Account 442 - Small	6,833,604	633,949,689	105,014	65,073	0.0928
24	Large Industrial Power Sales:					
25	75 Partial Requirements Service	449,638	22,152,941	1	449,638,000	0.0493
26	89-T Large Nonresidential	68,915	5,033,996	4	17,228,750	0.0730
27	85-P Large Nonresidential	713,695	52,329,746	176	4,055,085	0.0733
28	89-P Large Nonresidential	826,406	53,716,104	17	48,612,118	0.0650
29	90-P Large Nonresidential	1,148,438	69,949,352	4	287,109,500	0.0609
30	489-T COS Opt-Out - Lg. Nonreside		4,127,539	3		
31	485-P COS Opt-Out - Lrg. Nonresid		5,617,963	42		
32	489-P COS Opt-Out - Lg. Nonreside		8,218,452	9		
33	585-P DAS - Large Nonresidential		399,661	4		
34	589-P DAS - Large Nonresidential		23,010			
35	Large Industrial Unbilled Revenue	3,527	-270,000			-0.0766
36	TOTAL Account 442 - Large	3,210,619	221,298,764	260	12,348,535	0.0689
37	Street Lighting					
38	Various Public Street and					
39	Highway Lighting:					
40	Street Lighting	98,136	17,197,203	217	452,240	0.1752
41	TOTAL Billed	17,735,823	1,730,183,811	840,993	21,089	0.0976
42	Total Unbilled Rev.(See Instr. 6)	-132,636	-9,190,000	0	0	0.0693
43	TOTAL	17,603,187	1,720,993,811	840,993	20,931	0.0978

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 Unbilled Rev	-1,035	-46,000			0.0444
2	TOTAL Account 444	97,101	17,151,203	217	447,470	0.1766
3	TOTAL Account 445					
4	Other Sales to Public Authorities					
5	Communication Devices Electr					
6	TOTAL Account 445					
7						
8						
9						
10						
11						
12						
13						
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36						
37						
38						
39						
40						
41	TOTAL Billed	17,735,823	1,730,183,811	840,993	21,089	0.0976
42	Total Unbilled Rev.(See Instr. 6)	-132,636	-9,190,000	0	0	0.0693
43	TOTAL	17,603,187	1,720,993,811	840,993	20,931	0.0978

Schedule Page: 304 Line No.: 13 Column: a
Rate Schedule 83 complete title: Large Nonresidential Standard Service (31 - 200 kW).

Schedule Page: 304 Line No.: 14 Column: a
Rate schedule 85 complete title: Large Nonresidential Standard Service (201 - 4,000 kW).

Schedule Page: 304 Line No.: 15 Column: a
Rate schedule 89 complete title: Large Nonresidential (>4,000 kW) Standard Service.

Schedule Page: 304 Line No.: 16 Column: a
Rate Schedule 485 complete title: Large Nonresidential (201 - 4,000 kW) Cost of Service Opt-out.

Schedule Page: 304 Line No.: 16 Column: b
Customers on this schedule can choose to purchase their energy from an Electricity Service Supplier (ESS) or PGE. PGE serves these customers by delivering the energy purchased from ESSs.

Schedule Page: 304 Line No.: 17 Column: a
Rate Schedule 489 complete title: Large Nonresidential (>4,000 kW) Cost of Service Opt-out.

Schedule Page: 304 Line No.: 17 Column: b
Customers on this schedule can choose to purchase their energy from an Electricity Service Supplier (ESS) or PGE. PGE serves this customer by delivering the energy purchased from ESSs.

Schedule Page: 304 Line No.: 19 Column: a
Rate Schedule 532 complete title: Small Nonresidential Direct Access Service.

Schedule Page: 304 Line No.: 19 Column: b
Customers on this schedule can choose to purchase their energy from an Electricity Service Supplier (ESS) or PGE. PGE serves these customers by delivering the energy purchased from ESSs.

Schedule Page: 304 Line No.: 20 Column: a
Rate Schedule 583 complete title: Large Nonresidential Direct Access Service (31 - 200 kW).

Schedule Page: 304 Line No.: 20 Column: b
Customers on this schedule can choose to purchase their energy from an Electricity Service Supplier (ESS) or PGE. PGE serves these customers by delivering the energy purchased from ESSs.

Schedule Page: 304 Line No.: 21 Column: a
Rate Schedule 585 complete title: Large Nonresidential Direct Access Service (201 - 4,000 kW).

Schedule Page: 304 Line No.: 21 Column: b
Customers on this schedule can choose to purchase their energy from an Electricity Service Supplier (ESS) or PGE. PGE serves these customers by delivering the energy purchased from ESSs.

Schedule Page: 304 Line No.: 26 Column: a
Rate schedule 89 complete title: Large Nonresidential (>4,000 kW) Standard Service.

Schedule Page: 304 Line No.: 27 Column: a
Rate schedule 85 complete title: Large Nonresidential Standard Service (201 - 4,000 kW)

Schedule Page: 304 Line No.: 28 Column: a
Rate schedule 89 complete title: Large Nonresidential (>4,000 kW) Standard Service.

Schedule Page: 304 Line No.: 29 Column: a
Rate schedule 90 complete title: Large Nonresidential Standard Service (>4,000 kW and Aggregate to >100 MWa)

Schedule Page: 304 Line No.: 30 Column: a
Rate Schedule 489 complete title: Large Nonresidential (>4,000 kW) Cost of Service Opt-out.

Schedule Page: 304 Line No.: 30 Column: b
Customers on this schedule can choose to purchase their energy from an Electricity Service Supplier (ESS) or PGE. PGE serves these customers by delivering the energy purchased from

ESSs.

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

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

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

Customers on this schedule can choose to purchase their energy from an Electricity Service Supplier (ESS) or PGE. PGE serves these customers by delivering the energy purchased from ESSs.

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

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

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

Customers on this schedule can choose to purchase their energy from an Electricity Service Supplier (ESS) or PGE. PGE serves these customers by delivering the energy purchased from ESSs.

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

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

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

Customers on this schedule can choose to purchase their energy from an Electricity Service Supplier (ESS) or PGE. PGE serves these customers by delivering the energy purchased from ESSs.

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

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

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

Customers on this schedule can choose to purchase their energy from an Electricity Service Supplier (ESS) or PGE. PGE serves these customers by delivering the energy purchased from ESSs.

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 2014/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	RQ SALES:					
2	Fale Safe Corporation	RQ	PGE-1	75	75	75
3						
4						
5	NON-RQ SALES:					
6	Arizona Public Service`	SF	WSPP-1	NA	NA	NA
7	Avista Corp	SF	WSPP-1	NA	NA	NA
8	Black Hills Power	SF	WSPP-1	NA	NA	NA
9	Bonneville Power Administration	SF	WSPP-1	NA	NA	NA
10	BP Energy Company	SF	PGE-11	NA	NA	NA
11	Brookfield Energy Marketing LP	SF	WSPP-1	NA	NA	NA
12	Burbank, City of	SF	WSPP-1	NA	NA	NA
13	California ISO	SF	CAISO	NA	NA	NA
14	Calpine Energy Services	SF	EEI	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 2014/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	Cargill Alliant LLC	SF	WSPP-1	NA	NA	NA
2	Chelan County, PUD No. 1, Washington	SF	WSPP-1	NA	NA	NA
3	Citigroup Energy Inc.	SF	WSPP-1	NA	NA	NA
4	Clatskanie County PUD, Washington	SF	WSPP-1	NA	NA	NA
5	Constellation Energy Commodities	SF	EEI	NA	NA	NA
6	CP Energy Marketing	SF	WSPP-1	NA	NA	NA
7	Douglas County, PUD No. 1, Washington	SF	WSPP-1	NA	NA	NA
8	EDF Trading NA	SF	WSPP-1	NA	NA	NA
9	Eugene Water & Electric Board	SF	WSPP-1	NA	NA	NA
10	Exelon	SF	WSPP-1	NA	NA	NA
11	Glendale, City of	SF	WSPP-1	NA	NA	NA
12	Grant County, PUD No. 2, Washington	SF	WSPP-1	NA	NA	NA
13	Gridforce Energy	SF	WSPP-1	NA	NA	NA
14	Iberdrola Renewables	SF	EEI	NA	NA	NA
	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 2014/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	Idaho Power Company	SF	WSPP-1	NA	NA	NA
2	J. Aron Company	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	Modesto Irrigation District	SF	WSPP-1	NA	NA	NA
7	Morgan Stanley Capital Group	SF	PGE-11	NA	NA	NA
8	NaturEner	SF	WSPP-1	NA	NA	NA
9	Nevada Power	SF	WSPP-1	NA	NA	NA
10	NextEra Energy Solutions Inc	SF	WSPP-1	NA	NA	NA
11	Northern California Power Agency	SF	WSPP-1	NA	NA	NA
12	NorthWestern Corporation	SF	WSPP-1	NA	NA	NA
13	Okanogan County PUD, Washington	SF	WSPP-1	NA	NA	NA
14	PacifiCorp	LU	PGE-11	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 2014/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.
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LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW): Average Monthly NCP Demand (e)	Actual Demand (MW): Average Monthly CP Demand (f)
1	PacifiCorp	SF	EEI	NA	NA	NA
2	Pacific Northwest Generating Company	SF	WSPP-1	NA	NA	NA
3	Powerex	SF	PGE-11	NA	NA	NA
4	PPL Energy Plus	SF	EEI	NA	NA	NA
5	PUD No. 1 of Clark County	SF	WSPP-1	NA	NA	NA
6	Puget Sound Energy	SF	WSPP-1	NA	NA	NA
7	Rainbow Energy Marketing	SF	WSPP-1	NA	NA	NA
8	Redding, City of	SF	WSPP-1	NA	NA	NA
9	Roseville, City of	SF	WSPP-1	NA	NA	NA
10	Sacramento Municipal Utility Distric	SF	WSPP-1	NA	NA	NA
11	Seattle City Light	SF	WSPP-1	NA	NA	NA
12	Shell Energy NA	SF	WSPP-1	NA	NA	NA
13	Sierra Pacific	SF	WSPP-1	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 2014/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).
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Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Southern California Edison	SF	EEI	NA	NA	NA
2	Tacoma, City of	SF	WSPP-1	NA	NA	NA
3	The Energy Authority	SF	WSPP-1	NA	NA	NA
4	TransAlta Energy Marketing	SF	EEI	NA	NA	NA
5	TransCanada Power	SF	WSPP-1	NA	NA	NA
6	Turlock Irrigation District	SF	WSPP-1	NA	NA	NA
7	Tuscon Electric Power Company	SF	WSPP-1	NA	NA	NA
8	Vitol Inc.	SF	WSPP-1	NA	NA	NA
9	Western Area Power Authority	SF	WSPP-1	NA	NA	NA
10						
11	REC Sale Deferred Revenues			NA	NA	NA
12						
13	Direct Access Deferral - 2014			NA	NA	NA
14	Direct Access Amortization - 2013			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 2014/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.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Direct Access Amortization - 2012			NA	NA	NA
2	PW2 Test Energy Reclass			NA	NA	NA
3						
4	Non-RQ Sales:					
5	Portland General Electric Company	SF	OA96137	NA	NA	NA
6						
7						
8						
9						
10						
11						
12						
13						
14						
	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 2014/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.
					1
	-69,384	532,902		463,518	2
					3
					4
					5
11,696		470,933		470,933	6
33,319		1,181,884		1,181,884	7
361		16,480		16,480	8
23,760		858,105		858,105	9
110,652		3,531,405		3,531,405	10
1,000		31,200		31,200	11
11,924		419,792		419,792	12
810,749		30,999,276		30,999,276	13
26,549		748,512		748,512	14
0	-69,384	532,902	0	463,518	
3,488,059	3,057,544	123,048,813	3,451,939	129,558,296	
3,488,059	**2,988,160**	**123,581,715**	**3,451,939**	**130,021,814**	

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.
125,253		4,446,566		4,446,566	1
3,203		90,999		90,999	2
93,393		2,986,531		2,986,531	3
207		6,608		6,608	4
129		4,395		4,395	5
799		28,783		28,783	6
1,267		62,277		62,277	7
269,712		10,481,138		10,481,138	8
12,728		377,208		377,208	9
30,464		1,011,411		1,011,411	10
2,459		88,750		88,750	11
6,654		303,220		303,220	12
63		1,538		1,538	13
376,028		13,760,199		13,760,199	14
0	-69,384	532,902	0	463,518	
3,488,059	3,057,544	123,048,813	3,451,939	129,558,296	
3,488,059	**2,988,160**	**123,581,715**	**3,451,939**	**130,021,814**	

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.
10,517		366,920		366,920	1
33,900		664,040		664,040	2
27,968			1,361,575	1,361,575	3
74,438		3,436,179		3,436,179	4
33,875		987,617		987,617	5
30,770		1,122,544		1,122,544	6
82,680		2,748,216		2,748,216	7
8		332		332	8
4,677		109,746		109,746	9
90		8,120		8,120	10
6,271		186,770		186,770	11
79,431		3,163,744		3,163,744	12
1,225		51,025		51,025	13
17,000			175,037	175,037	14
0	-69,384	532,902	0	463,518	
3,488,059	3,057,544	123,048,813	3,451,939	129,558,296	
3,488,059	**2,988,160**	**123,581,715**	**3,451,939**	**130,021,814**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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.
58,015		2,225,876		2,225,876	1
16,080		746,820		746,820	2
141,807		4,022,746		4,022,746	3
9,963		332,425		332,425	4
4,392		146,770		146,770	5
183,422		5,851,498		5,851,498	6
28,923		884,287		884,287	7
31,460		1,042,996		1,042,996	8
1,570		77,644		77,644	9
98,997		3,351,473		3,351,473	10
52,829		2,059,537		2,059,537	11
146,482		4,728,452		4,728,452	12
25		125		125	13
3,878		157,518		157,518	14
0	-69,384	532,902	0	463,518	
3,488,059	3,057,544	123,048,813	3,451,939	129,558,296	
3,488,059	**2,988,160**	**123,581,715**	**3,451,939**	**130,021,814**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

SALES FOR RESALE (Account 447) (Continued)

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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.
82,275		2,968,445		2,968,445	1
2,019		54,032		54,032	2
11,645		403,077		403,077	3
87,199		2,711,171		2,711,171	4
38,040		1,871,503		1,871,503	5
56,283		2,047,405		2,047,405	6
2,940		139,736		139,736	7
94,823		3,371,204		3,371,204	8
1,200		33,800		33,800	9
					10
			2,965,335	2,965,335	11
					12
			-512,767	-512,767	13
			-568,209	-568,209	14
0	-69,384	532,902	0	463,518	
3,488,059	3,057,544	123,048,813	3,451,939	129,558,296	
3,488,059	**2,988,160**	**123,581,715**	**3,451,939**	**130,021,814**	

SALES FOR RESALE (Account 447) (Continued)

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

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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.
			30,968	30,968	1
-32,591		-944,640		-944,640	2
					3
					4
11,164	3,057,544	12,450		3,069,994	5
					6
					7
					8
					9
					10
					11
					12
					13
					14
0	-69,384	532,902	0	463,518	
3,488,059	3,057,544	123,048,813	3,451,939	129,558,296	
3,488,059	**2,988,160**	**123,581,715**	**3,451,939**	**130,021,814**	

Schedule Page: 310 Line No.: 2 Column: c

Certificate of Concurrence in Fale-Safe's Tariff No. 1 has been filed with FERC.

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: 310.2 Line No.: 14 Column: j

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

Schedule Page: 310.4 Line No.: 11 Column: j

Deferred revenues for Renewable Energy Credit sales which were made before the title transferred to buyer.

Schedule Page: 310.4 Line No.: 13 Column: j

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

Schedule Page: 310.4 Line No.: 14 Column: j

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

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

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

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

Port Westward 2 test energy reclassified to capital.

Schedule Page: 310.5 Line No.: 5 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 2014/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	2,261,040	2,155,656
5	(501) Fuel	95,128,264	72,917,094
6	(502) Steam Expenses	6,652,434	4,930,412
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses	10,234,615	5,651,322
11	(507) Rents	60,036	40,452
12	(509) Allowances	113,328	138,960
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	114,449,717	85,833,896
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	1,154,943	749,347
16	(511) Maintenance of Structures	1,468,330	1,019,602
17	(512) Maintenance of Boiler Plant	7,935,735	6,737,423
18	(513) Maintenance of Electric Plant	19,692,450	12,056,252
19	(514) Maintenance of Miscellaneous Steam Plant	1,003,944	793,806
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	31,255,402	21,356,430
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	145,705,119	107,190,326
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	630,058	618,646
45	(536) Water for Power	540,191	545,040
46	(537) Hydraulic Expenses	5,094,411	4,659,071
47	(538) Electric Expenses	1,024,224	1,080,812
48	(539) Miscellaneous Hydraulic Power Generation Expenses	3,633,678	2,690,890
49	(540) Rents	753,477	543,556
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	11,676,039	10,138,015
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	524,048	665,534
54	(542) Maintenance of Structures	8,456	44,308
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,857,006	561,882
56	(544) Maintenance of Electric Plant	1,350,764	1,567,244
57	(545) Maintenance of Miscellaneous Hydraulic Plant	1,562,541	1,200,908
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	5,302,815	4,039,876
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	16,978,854	14,177,891

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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	2,893,680	2,290,494
63	(547) Fuel	156,007,795	207,138,283
64	(548) Generation Expenses	5,399,377	4,773,297
65	(549) Miscellaneous Other Power Generation Expenses	5,199,404	5,603,666
66	(550) Rents	286,118	281,224
67	TOTAL Operation (Enter Total of lines 62 thru 66)	169,786,374	220,086,964
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	1,533,108	993,826
70	(552) Maintenance of Structures	376,597	481,179
71	(553) Maintenance of Generating and Electric Plant	32,173,922	35,663,407
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	373,821	309,386
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	34,457,448	37,447,798
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	204,243,822	257,534,762
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	414,524,300	441,802,271
77	(556) System Control and Load Dispatching	74,735	80,921
78	(557) Other Expenses	16,533,641	16,827,789
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	431,132,676	458,710,981
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	798,060,471	837,613,960
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	4,152,570	3,495,647
84			
85	(561.1) Load Dispatch-Reliability	13,201	13,328
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	589,795	562,399
87	(561.3) Load Dispatch-Transmission Service and Scheduling	920,494	826,988
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	124,864	792,363
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		122,583
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	216,775	206,294
94	(563) Overhead Lines Expenses	26,629	199,023
95	(564) Underground Lines Expenses	2,888	
96	(565) Transmission of Electricity by Others	82,339,358	74,555,702
97	(566) Miscellaneous Transmission Expenses	2,797,510	3,123,421
98	(567) Rents	2,578,304	2,309,687
99	TOTAL Operation (Enter Total of lines 83 thru 98)	93,762,388	86,207,435
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	48,555	42,407
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software	1,000,377	975,907
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,317,234	861,968
108	(571) Maintenance of Overhead Lines	437,575	475,971
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	1,096	
111	TOTAL Maintenance (Total of lines 101 thru 110)	2,804,837	2,356,253
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	96,567,225	88,563,688

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	18,457,253	20,616,178
135	(581) Load Dispatching	1,818,721	1,709,316
136	(582) Station Expenses	1,012,425	811,225
137	(583) Overhead Line Expenses	1,468,773	1,573,615
138	(584) Underground Line Expenses	2,822,869	2,463,074
139	(585) Street Lighting and Signal System Expenses	204,822	573,732
140	(586) Meter Expenses	3,713,534	2,992,777
141	(587) Customer Installations Expenses	3,049,623	3,033,787
142	(588) Miscellaneous Expenses	11,526,163	6,387,753
143	(589) Rents	1,608,235	1,622,187
144	TOTAL Operation (Enter Total of lines 134 thru 143)	45,682,418	41,783,644
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	111,615	33,250
147	(591) Maintenance of Structures	138,981	140,003
148	(592) Maintenance of Station Equipment	4,407,846	3,650,066
149	(593) Maintenance of Overhead Lines	38,122,269	29,788,653
150	(594) Maintenance of Underground Lines	5,055,021	3,932,768
151	(595) Maintenance of Line Transformers	605,339	210,877
152	(596) Maintenance of Street Lighting and Signal Systems	1,370,196	1,687,834
153	(597) Maintenance of Meters	188,834	359,299
154	(598) Maintenance of Miscellaneous Distribution Plant	4,156,684	4,830,616
155	TOTAL Maintenance (Total of lines 146 thru 154)	54,156,785	44,633,366
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	99,839,203	86,417,010
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision		
160	(902) Meter Reading Expenses	739,908	885,612
161	(903) Customer Records and Collection Expenses	39,382,359	36,570,856
162	(904) Uncollectible Accounts	6,899,174	6,305,647
163	(905) Miscellaneous Customer Accounts Expenses	4,809,473	5,061,959
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	51,830,914	48,824,074

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	12,086,884	11,336,359
169	(909) Informational and Instructional Expenses	2,091,727	1,951,378
170	(910) Miscellaneous Customer Service and Informational Expenses		
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	14,178,611	13,287,737
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	58,438,223	52,776,420
182	(921) Office Supplies and Expenses	17,806,181	16,402,647
183	(Less) (922) Administrative Expenses Transferred-Credit	9,527,094	10,151,576
184	(923) Outside Services Employed	7,080,592	8,498,581
185	(924) Property Insurance	4,516,221	4,501,427
186	(925) Injuries and Damages	2,418,111	4,909,107
187	(926) Employee Pensions and Benefits	59,935,856	59,857,913
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	7,170,660	7,498,336
190	(929) (Less) Duplicate Charges-Cr.	2,263,775	2,167,352
191	(930.1) General Advertising Expenses	560,593	616,151
192	(930.2) Miscellaneous General Expenses	8,482,432	8,723,902
193	(931) Rents	4,680,348	3,522,784
194	TOTAL Operation (Enter Total of lines 181 thru 193)	159,298,348	154,988,340
195	Maintenance		
196	(935) Maintenance of General Plant	2,473,930	2,730,426
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	161,772,278	157,718,766
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	1,222,248,702	1,232,425,235

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 2014/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Avista Corp. - AVWP (was WWP)	SF	WSPP-1	NA	NA	NA
2	Baldock Solar	LU	Baldock	NA	NA	NA
3	Bellevue Solar	LU	Bellevue	NA	NA	NA
4	Black Hills Power	SF	WSPP-1	NA	NA	NA
5	Bonneville Power Administration	SF	WSPP-1	NA	NA	NA
6	Brookfield Energy Marketing	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	PGE-11	NA	NA	NA
11	Cargill Alliant LLC	SF	WSPP-1	NA	NA	NA
12	Chelan County, PUD No. 1, Washington	SF	WSPP-1	NA	NA	NA
13	Citigroup Energy	SF	WSPP-1	NA	NA	NA
14	Clatskanie County PUD	SF	WSPP-1	NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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PURCHASED POWER (Account 555)
(Including power exchanges)

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1	ConocoPhillips	SF	WSPP-1	NA	NA	NA
2	Constellation Energy Commodities	SF	PGE-11	NA	NA	NA
3	Covanta Marion	LU	QF83-118	NA	NA	NA
4	CP Energy Marketing (US)	SF	WSPP-1	NA	NA	NA
5	Douglas County, PUD No. 1, Washington	LU	Wells	NA	NA	NA
6	Douglas County, PUD No. 1, Washington	LF	Wells	NA	NA	NA
7	Douglas County, PUD No. 1, Washington	SF	WSPP-1	NA	NA	NA
8	EDF Trading North America, LLC	SF	WSPP-1	NA	NA	NA
9	ESI Vansycle Partners, LP	LU	WSPP-1	NA	NA	NA
10	Eugene Water & Electric Board	LU	WSPP-1	NA	NA	NA
11	Eugene Water & Electric Board	OS	ER94-717	NA	NA	NA
12	Eugene Water & Electric Board	SF	WSPP-1	NA	NA	NA
13	Eugene Water & Electric Board	EX	WSPP-1	NA	NA	NA
14	Exelon Generation Co.	SF	WSPP-1	NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Forest Glen Oaks Biomass	LU	FGO	NA	NA	NA
2	Glendale, City of	SF	WSPP-1	NA	NA	NA
3	Grant County, PUD No. 2, Washington	LU	Wanapum	NA	NA	NA
4	Grant County, PUD No. 2, Washington	LU	Priest Rapids	NA	NA	NA
5	Grant County, PUD No. 2, Washington	SF	WSPP-1	NA	NA	NA
6	Iberdrola Renewables	SF	PGE-11	NA	NA	NA
7	Iberdrola Renewables	LU	PGE-11	NA	NA	NA
8	Iberdrola Renewables	LU	PGE-11	NA	NA	NA
9	Idaho Falls, City of	SF	WSPP-1	NA	NA	NA
10	Idaho Power Company	SF	WSPP-1	NA	NA	NA
11	J. Aron Company	SF	PGE-11	NA	NA	NA
12	JC Biomethane	LF	JCBIO	NA	NA	NA
13	JP Morgan Ventures	SF	WSPP-1	NA	NA	NA
14	Load Balance Energy	OS	OATT	NA	NA	NA
	Total					

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PURCHASED POWER (Account 555)
(Including power exchanges)

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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	Noble Americas Gas & Power	SF	WSPP-1	NA	NA	NA
10	Northern Wasco PUD Hydro	LU	NWASCO	NA	NA	NA
11	NorthWestern Corporation	SF	WSPP-1	NA	NA	NA
12	Okanogan County PUD, Washington	SF	WSPP-1	NA	NA	NA
13	Outback Solar	LU	Outback	NA	NA	NA
14	PacifiCorp	RQ	PP&L 147	NA	NA	NA
	Total					

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PURCHASED POWER (Account 555)
(Including power exchanges)

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1	PacifiCorp	SF	PGE-11	NA	NA	NA
2	PaTu Wind	LU	WSPP-1	NA	NA	NA
3	Portland, City of	LU	#2821	NA	NA	NA
4	Powerex	SF	PGE-11	NA	NA	NA
5	PPL Energy Plus	SF	PGE-11	NA	NA	NA
6	PRC - Coffin Butte Biomass	LU	PRC	NA	NA	NA
7	Public Service Company of New Mexico	SF	WSPP-1	NA	NA	NA
8	Public Utility District No. 1 of Clark	SF	WSPP-1	NA	NA	NA
9	Puget Sound Energy	SF	WSPP-1	NA	NA	NA
10	Rainbow Energy Marketing	SF	WSPP-1	NA	NA	NA
11	Roseville, City of	SF	WSPP-1	NA	NA	NA
12	Sacramento Municipal Utility District	SF	WSPP-1	NA	NA	NA
13	Seattle City Light	SF	WSPP-1	NA	NA	NA
14	Shell Energy	SF	WSPP-1	NA	NA	NA
	Total					

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1	Sierra Pacific	SF	WSPP-1	NA	NA	NA
2	Snohomish County, PUD No. 1, Washingtn	SF	WSPP-1	NA	NA	NA
3	Southern California Edison	SF	PGE-11	NA	NA	NA
4	Spokane Energy, LLC	LF	PGE-82	NA	NA	NA
5	Spokane Energy, LLC	EX	PGE-82	NA	NA	NA
6	Tacoma, City of	SF	WSPP-1	NA	NA	NA
7	Tenaska	SF	WSPP-1	NA	NA	NA
8	The Energy Authority	SF	WSPP-1	NA	NA	NA
9	Tillamook Biomass	LU	TBIO	NA	NA	NA
10	TransAlta Energy Marketing	SF	PGE-11	NA	NA	NA
11	TransAlta Energy Marketing	LF	PGE-11	NA	NA	NA
12	TransCanada Energy Marketing	SF	WSPP-1	NA	NA	NA
13	Turlock Irrigation District	SF	WSPP-1	NA	NA	NA
14	Tuscon Electric Power	SF	WSPP-1	NA	NA	NA
	Total					

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PURCHASED POWER (Account 555)
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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	Vitol Inc	SF	WSPP-1	NA	NA	NA
2	Warm Springs Power Enterprises	LU	WSPP-1	NA	NA	NA
3	Western Area Power Authority	SF	WSPP-1	NA	NA	NA
4	Yamhill Solar	LU	Yamhill	NA	NA	NA
5	Lake Oswego Corporation	LU	201	NA	NA	NA
6	Country Village Estates	OS	201	NA	NA	NA
7	Domaine Drouhin	OS	201	NA	NA	NA
8	Von Land Co	OS	201	NA	NA	NA
9	Minikahada Hydropower Co	OS	201	NA	NA	NA
10	Starbucks	OS	201	NA	NA	NA
11	SunWay LLC	LU	201	NA	NA	NA
12	Solar Payment Option	OS	215-217	NA	NA	NA
13	Tualatin Valley Water Dist	OS	201	NA	NA	NA
14	Oregon Heat	OS	203	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 2014/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	Load Curtailment Program			NA	NA	NA
2	Margin on Electric Financials			NA	NA	NA
3	Reserve Trading Credit Risk			NA	NA	NA
4	Green Power			NA	NA	NA
5	REC Retirement Expense			NA	NA	NA
6	Carbon Allowance Expense			NA	NA	NA
7						
8	Non-cash exchanges			NA	NA	NA
9	Energy Storage Expense					
10						
11						
12						
13						
14						
	Total					

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a 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	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received	MegaWatt Hours Delivered	Demand Charges ($)	Energy Charges ($)	Other Charges ($)	Total (j+k+l) of Settlement ($)	
(g)	(h)	(i)	(j)	(k)	(l)	(m)	
44,975				3,215,156		3,215,156	1
2,174							2
1,696				167,595		167,595	3
91				3,575		3,575	4
332,394				7,844,408		7,844,408	5
600				45,800		45,800	6
44,000				1,801,860		1,801,860	7
1,389				43,479		43,479	8
203,509				3,135,666		3,135,666	9
121,819				5,576,460		5,576,460	10
14,650				608,068		608,068	11
9,420				332,998		332,998	12
400				200		200	13
3,634				103,155		103,155	14
11,392,970	454,243	452,897	21,112,400	360,929,903	32,481,997	414,524,300	

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.
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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.
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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.
3,600				150,200		150,200	1
2,304				99,169		99,169	2
87,736				4,534,700		4,534,700	3
1,420				39,570		39,570	4
790,724				9,737,932		9,737,932	5
216,558				6,333,298		6,333,298	6
57,085				2,307,042		2,307,042	7
37,917				1,462,223		1,462,223	8
68,006				4,085,440		4,085,440	9
			399,400			399,400	10
1,698							11
37,923				1,076,242		1,076,242	12
	13,143	10,772					13
69,166				2,031,374		2,031,374	14
11,392,970	454,243	452,897	21,112,400	360,929,903	32,481,997	414,524,300	

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
691				35,188		35,188	1
503				12,895		12,895	2
397,669							3
285,959				14,301,536		14,301,536	4
65,633				1,506,355		1,506,355	5
449,780				14,976,843		14,976,843	6
213,665				11,314,574		11,314,574	7
			1,615,000			1,615,000	8
200				4,800		4,800	9
67,385				2,489,490		2,489,490	10
22,200				1,146,720		1,146,720	11
8,413				376,564		376,564	12
11,810				356,239		356,239	13
2,904				93,300		93,300	14
11,392,970	454,243	452,897	21,112,400	360,929,903	32,481,997	414,524,300	

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
875				-45,276		-45,276	1
74,181				2,292,068		2,292,068	2
823				22,128		22,128	3
85,111				1,695,296		1,695,296	4
1				37		37	5
2,310				142,600		142,600	6
1,050				17,963		17,963	7
264,995				10,150,532		10,150,532	8
22,600				1,048,778		1,048,778	9
41,501				1,914,287		1,914,287	10
-8,989				696,466		696,466	11
22,099				620,955		620,955	12
10,764				962,985		962,985	13
11,443				1,158,754		1,158,754	14
11,392,970	454,243	452,897	21,112,400	360,929,903	32,481,997	414,524,300	

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.
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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.
253,894				7,334,546		7,334,546	1
34,907				2,465,351		2,465,351	2
94,055				4,519,120		4,519,120	3
112,621				5,795,585		5,795,585	4
73,907				2,647,630		2,647,630	5
45,775				2,113,770		2,113,770	6
6				264		264	7
23,952				699,688		699,688	8
123,310				3,894,705		3,894,705	9
3,806				154,900		154,900	10
110				1,905		1,905	11
5,917				276,166		276,166	12
261,360				8,103,531		8,103,531	13
3,754,094				117,419,427		117,419,427	14
11,392,970	454,243	452,897	21,112,400	360,929,903	32,481,997	414,524,300	

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
130				5,590		5,590	1
69,209				1,543,330		1,543,330	2
192,839				3,142,076		3,142,076	3
			19,098,000			19,098,000	4
	441,100	442,125					5
103,367				2,643,214		2,643,214	6
47,893				873,854		873,854	7
96,002				2,260,506		2,260,506	8
5,898				239,374		239,374	9
264,180				10,531,412		10,531,412	10
872,396				36,857,765		36,857,765	11
13,776				508,183		508,183	12
73,512				1,342,560		1,342,560	13
45				1,575		1,575	14
11,392,970	454,243	452,897	21,112,400	360,929,903	32,481,997	414,524,300	

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

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

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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)	
86,800				3,493,773		3,493,773	1
552,276				18,959,501		18,959,501	2
490				15,600		15,600	3
1,348				133,144		133,144	4
431				30,782		30,782	5
45				1,916		1,916	6
109				3,576		3,576	7
193				7,544		7,544	8
324				15,019		15,019	9
29				2,370		2,370	10
3,283				269,740		269,740	11
9,276				581,456		581,456	12
334				11,768		11,768	13
607					19,279	19,279	14
11,392,970	454,243	452,897	21,112,400	360,929,903	32,481,997	414,524,300	

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 2014/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
					1,032,611	1,032,611	1
					23,444,106	23,444,106	2
					37,340	37,340	3
					6,913,981	6,913,981	4
					609,851	609,851	5
					436,199	436,199	6
							7
					-11,370	-11,370	8
							9
							10
							11
							12
							13
							14
11,392,970	454,243	452,897	21,112,400	360,929,903	32,481,997	414,524,300	

Schedule Page: 326.1 Line No.: 5 Column: c

Non jurisdictional utilities.

Schedule Page: 326.1 Line No.: 6 Column: b

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

Schedule Page: 326.1 Line No.: 11 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: 326.1 Line No.: 12 Column: c

Non jurisdictional utilities.

Schedule Page: 326.2 Line No.: 3 Column: c

Non jurisdictional utilities.

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: 326.3 Line No.: 8 Column: b

The NextEra contract expires 12/31/15.

Schedule Page: 326.5 Line No.: 2 Column: c

Non jurisdictional utilities.

Schedule Page: 326.5 Line No.: 4 Column: b

The Spokane Energy, LLC contract expires on 12/31/16.

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

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

Schedule Page: 326.6 Line No.: 6 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

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

Schedule Page: 326.6 Line No.: 10 Column: b

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

Schedule Page: 326.6 Line No.: 12 Column: b

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

Schedule Page: 326.6 Line No.: 13 Column: b

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

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

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

Schedule Page: 326.7 Line No.: 1 Column: l

Power purchased under Load Curtailment Program.

Schedule Page: 326.7 Line No.: 2 Column: l

Margin on electric financial transactions.

Schedule Page: 326.7 Line No.: 3 Column: l

Reserve for trading credit risk.

Schedule Page: 326.7 Line No.: 4 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: 326.7 Line No.: 5 Column: l

Expense of annual REC retirement to meet RPS compliance.

Schedule Page: 326.7 Line No.: 6 Column: l

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

Schedule Page: 326.7 Line No.: 9 Column: g

There are no costs recorded in Account 555.1, Power Purchased for Storage, as the Company did not purchase power for storage purposes during 2014.

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 2014/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	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	Bonneville Power Administration	Bonneville Power Administration	CAISO	NF
4	Bonneville Power Administration	Bonneville Power Administration	Portland General Electric	FNO
5	Bonneville Power Administration	Bonneville Power Administration	Western Oregon Electric Coop	OLF
6	Bonneville Power Administration	Bonneville Power Administration	Other TVI Pumps	OLF
7	Bonneville Power Administration	Bonneville Power Administration	Canby People's Utility District	OLF
8	Bonneville Power Administration	Bonneville Power Administration	Columbia River PUD	OLF
9	Cargill Power Markets, LLC	Bonneville Power Administration	Balancing Authority of N. Calif	NF
10	Cargill Power Markets, LLC	Bonneville Power Administration	Balancing Authority of N. Calif	SFP
11	Cargill Power Markets, LLC	Bonneville Power Administration	CAISO	SFP
12	Cargill Power Markets, LLC	Bonneville Power Administration	CAISO	NF
13	Cargill Power Markets, LLC	Bonneville Power Administration	Portland General Electric	OS
14	EDF Trading North America LLC	Bonneville Power Administration	CAISO	NF
15	Exelon Generation Company LLC	Bonneville Power Administration	Balancing Authority of N. Calif	LFP
16	Exelon Generation Company LLC	Bonneville Power Administration	CAISO	LFP
17	Exelon Generation Company LLC	Bonneville Power Administration	CAISO	NF
18	Iberdrola Renewables Inc.	Bonneville Power Administration	Balancing Authority of N. Calif	NF
19	Iberdrola Renewables Inc.	Bonneville Power Administration	Bonneville Power Administration	NF
20	Iberdrola Renewables Inc.	Bonneville Power Administration	PacifiCorp	NF
21	Iberdrola Renewables Inc.	CAISO	Bonneville Power Administration	NF
22	Macquarie Energy LLC	Balancing Authority of N. Calif	Bonneville Power Administration	NF
23	Macquarie Energy LLC	Bonneville Power Administration	Balancing Authority of N. Calif	NF
24	Macquarie Energy LLC	Bonneville Power Administration	CAISO	SFP
25	Macquarie Energy LLC	Bonneville Power Administration	CAISO	NF
26	Macquarie Energy LLC	CAISO	Bonneville Power Administration	NF
27	Macquarie Energy LLC	CAISO	Bonneville Power Administration	SFP
28	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	Balancing Authority of N. Calif	SFP
29	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	Balancing Authority of N. Calif	NF
30	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	Balancing Authority of N. Calif	LFP
31	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	CAISO	LFP
32	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	CAISO	NF
33	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	CAISO	SFP
34	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	PacifiCorp	NF
	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 2014/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Morgan Stanley Capital Group Inc.	CAISO	Bonneville Power Administration	NF
2	Morgan Stanley Capital Group Inc.	CAISO	Bonneville Power Administration	OS
3	Nextera Energy Power Marketing, LLC	Bonneville Power Administration	CAISO	NF
4	Noble Americas Energy Solutions	Bonneville Power Administration	Portland General Electric	NF
5	Noble Americas Energy Solutions	Portland General Electric	Portland General Electric	NF
6	Pacificorp	PacifiCorp	Portland General Electric	OLF
7	Powerex Corp.	Balancing Authority of N. Calif	Bonneville Power Administration	NF
8	Powerex Corp.	Bonneville Power Administration	Balancing Authority of N. Calif	NF
9	Powerex Corp.	Bonneville Power Administration	Balancing Authority of N. Calif	LFP
10	Powerex Corp.	Bonneville Power Administration	CAISO	LFP
11	Powerex Corp.	Bonneville Power Administration	CAISO	NF
12	Powerex Corp.	Bonneville Power Administration	PacifiCorp	LFP
13	Powerex Corp.	Bonneville Power Administration	PacifiCorp	NF
14	Powerex Corp.	CAISO	Bonneville Power Administration	OS
15	Powerex Corp.	CAISO	Bonneville Power Administration	NF
16	Powerex Corp.			OS
17	PUD No. 1 of Cowlitz County			LFP
18	PUD No. 1 of Franklin County			LFP
19	PUD No. 1 of Klickitat County			LFP
20	PUD No. 1 of Lewis County			LFP
21	Puget Sound Energy	Balancing Authority of N. Calif	Bonneville Power Administration	LFP
22	Puget Sound Energy	Bonneville Power Administration	Bonneville Power Administration	LFP
23	Puget Sound Energy	Bonneville Power Administration	CAISO	OS
24	Puget Sound Energy	CAISO	Bonneville Power Administration	LFP
25	Puget Sound Energy	CAISO	Bonneville Power Administration	NF
26	Puget Sound Energy	CAISO	Bonneville Power Administration	SFP
27	Rainbow Energy Marketing Corp	Bonneville Power Administration	CAISO	LFP
28	Rainbow Energy Marketing Corp			OS
29	Sacramento Municipal Utility Dist	Bonneville Power Administration	Balancing Authority of N. Calif	NF
30	Seattle City Light Marketing	Bonneville Power Administration	Balancing Authority of N. Calif	NF
31	Seattle City Light Marketing	Bonneville Power Administration	CAISO	NF
32	Shell Energy North America (US), L.P.	Bonneville Power Administration	Balancing Authority of N. Calif	NF
33	Shell Energy North America (US), L.P.	Bonneville Power Administration	Balancing Authority of N. Calif	LFP
34	Shell Energy North America (US), L.P.	Bonneville Power Administration	CAISO	LFP
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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	Shell Energy North America (US), L.P.	Bonneville Power Administration	CAISO	NF
2	Shell Energy North America (US), L.P.	Bonneville Power Administration	PacifiCorp	NF
3	Shell Energy North America (US), L.P.	Bonneville Power Administration	PacifiCorp	LFP
4	Shell Energy North America (US), L.P.	CAISO	Bonneville Power Administration	NF
5	Shell Energy North America (US), L.P.	CAISO	Bonneville Power Administration	OS
6	Southern California Edison	Bonneville Power Administration	CAISO	NF
7	The Energy Authority	Balancing Authority of N. Calif	Bonneville Power Administration	OS
8	The Energy Authority	Balancing Authority of N. Calif	Bonneville Power Administration	NF
9	The Energy Authority	Bonneville Power Administration	Balancing Authority of N. Calif	NF
10	The Energy Authority	Bonneville Power Administration	Balancing Authority of N. Calif	LFP
11	The Energy Authority	Bonneville Power Administration	CAISO	LFP
12	The Energy Authority	Bonneville Power Administration	CAISO	NF
13	The Energy Authority	CAISO	Bonneville Power Administration	NF
14	The Energy Authority	CAISO	Bonneville Power Administration	OS
15	The Energy Authority		RESALE to Cargill Power Markets,	SFP
16	TransAlta Energy Marketing U.S. Inc.	Bonneville Power Administration	Balancing Authority of N. Calif	NF
17	TransAlta Energy Marketing U.S. Inc.	Bonneville Power Administration	CAISO	NF
18	TransAlta Energy Marketing U.S. Inc.	Bonneville Power Administration	PacifiCorp	NF
19	TransAlta Energy Marketing U.S. Inc.	CAISO	Bonneville Power Administration	NF
20	TransAlta Energy Marketing U.S. Inc.	CAISO	Bonneville Power Administration	SFP
21	Turlock Irrigation District	Bonneville Power Administration	Balancing Authority of N. Calif	NF
22	Accrual			AD
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	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 2014/Q4

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

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
8	John Day	Captain Jack		106,393	106,393	1
8	John Day	Malin 500		529,347	529,347	2
8	John Day	Malin 500		4,719	4,719	3
8	BPAT.PGE	PGE		88,858	88,818	4
72	Various Subs	Various Subs		14,489	12,463	5
72	Various Subs	Various Subs		10,248	8,815	6
72	Various Subs	Various Subs		156,133	134,301	7
72	Various Subs	Various Subs		250,200	215,215	8
8	John Day	Captain Jack		1,672	1,672	9
8	John Day	Captain Jack		15,943	15,943	10
8	John Day	Malin 500		3,075	3,075	11
8	John Day	Malin 500		150	150	12
8	BPAT.PGE	PGE		153	153	13
8	John Day	Malin 500		3,125	3,125	14
8	John Day	Captain Jack		76	76	15
8	John Day	Malin 500		40,433	40,433	16
8	John Day	Malin 500		7,541	7,541	17
8	John Day	Captain Jack		51	51	18
8	K Falls Gen	John Day		485	485	19
8	John Day	Malin 500		6	6	20
8	Malin 500	John Day		3,506	3,506	21
8	Captain Jack	John Day		175	175	22
8	John Day	Captain Jack		260	260	23
8	John Day	Malin 500		30	30	24
8	John Day	Malin 500		46,843	46,843	25
8	Malin 500	John Day		14,112	14,112	26
8	Malin 500	John Day		2,350	2,350	27
8	John Day	Captain Jack		38,075	38,075	28
8	John Day	Captain Jack		10,760	10,760	29
8	John Day	Captain Jack		157,268	157,268	30
8	John Day	Malin 500		20,025	20,025	31
8	John Day	Malin 500		20,418	20,418	32
8	John Day	Malin 500		430	430	33
8	John Day	Malin 500		25	25	34
			0	**6,762,016**	**6,579,608**	

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 2014/Q4

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

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
8	Malin 500	John Day		14,986	14,986	1
8	Malin 500	John Day		1,086	1,086	2
8	John Day	Malin 500		28,842	28,842	3
8	BPAT.PGE	PGE		1,692,046	1,567,611	4
8	PGE.Internal	PGE		2,600	2,408	5
Exch	John Day	Various Subs		1,706	4,241	6
8	Captain Jack	John Day		75	75	7
8	John Day	Captain Jack		28,157	28,157	8
8	John Day	Captain Jack		102,556	102,556	9
8	John Day	Malin 500		1,663,817	1,663,817	10
8	John Day	Malin 500		84,834	84,834	11
8	John Day	Malin 500		377	377	12
8	John Day	Malin 500		3,291	3,291	13
8	Malin 500	John Day		1,619	1,619	14
8	Malin 500	John Day		5,702	5,702	15
8	John Day	COB				16
8	John Day	COB				17
8	John Day	COB				18
8	John Day	COB				19
8	John Day	COB				20
8	Captain Jack	John Day		5	5	21
8	K Falls Gen	John Day		5,575	5,575	22
8	John Day	Malin 500		3,813	3,813	23
8	Malin 500	John Day		26,381	26,381	24
8	Malin 500	John Day		9,161	9,161	25
8	Malin 500	John Day		83,117	83,117	26
8	John Day	Malin 500		320	320	27
8	John Day	Malin 500				28
8	John Day	Captain Jack		15	15	29
8	John Day	Captain Jack		2,068	2,068	30
8	John Day	Malin 500		40	40	31
8	John Day	Captain Jack		112	112	32
8	John Day	Captain Jack		58,521	58,521	33
8	John Day	Malin 500		1,105,925	1,105,925	34
			0	**6,762,016**	**6,579,608**	

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 2014/Q4

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

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
8	John Day	Malin 500		25,596	25,596	1
8	John Day	Malin 500		466	466	2
8	John Day	Malin 500		449	449	3
8	Malin 500	John Day		828	828	4
8	Malin 500	John Day		1,311	1,311	5
8	John Day	Malin 500		16,671	16,671	6
8	Captain Jack	John Day		396	396	7
8	Captain Jack	John Day		4,124	4,124	8
8	John Day	Captain Jack		7,762	7,762	9
8	John Day	Captain Jack		54,963	54,963	10
8	John Day	Malin 500		109,517	109,517	11
8	John Day	Malin 500		84	84	12
8	Malin 500	John Day		7,427	7,427	13
8	Malin 500	John Day		668	668	14
8	John Day	COB				15
8	John Day	Captain Jack		56	56	16
8	John Day	Malin 500		16,994	16,994	17
8	John Day	Malin 500		98	98	18
8	Malin 500	John Day		17,660	17,660	19
8	Malin 500	John Day		8,225	8,225	20
8	John Day	Captain Jack		14,600	14,600	21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			0	**6,762,016**	**6,579,608**	

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.
	107,606		107,606	1
	535,383		535,383	2
	6,540		6,540	3
84,446		1,962	86,408	4
	109,632	-3,391	106,241	5
	37,056		37,056	6
	359,149	-92,991	266,158	7
	26,228	-91,992	-65,764	8
	1,794		1,794	9
	30,198		30,198	10
	5,824		5,824	11
	161		161	12
				13
	2,778		2,778	14
	100		100	15
	52,997		52,997	16
	20,978		20,978	17
	56		56	18
	535		535	19
	7		7	20
	3,867		3,867	21
	201		201	22
	298		298	23
	63		63	24
	53,700		53,700	25
	16,178		16,178	26
	4,968		4,968	27
	52,970		52,970	28
	13,626		13,626	29
	126,780		126,780	30
	16,143		16,143	31
	25,856		25,856	32
	598		598	33
	32		32	34
1,750,236	**6,176,770**	**100,224**	**8,027,230**	

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.
	18,977		18,977	1
				2
	33,606		33,606	3
1,663,234			1,663,234	4
2,556			2,556	5
		247,287	247,287	6
	132		132	7
	49,430		49,430	8
	559,053		559,053	9
	9,069,793		9,069,793	10
	148,928		148,928	11
	2,055		2,055	12
	5,777		5,777	13
				14
	10,010		10,010	15
	-7,827,882		-7,827,882	16
	64,299		64,299	17
	64,299		64,299	18
	70,729		70,729	19
	70,729		70,729	20
	101		101	21
	112,157		112,157	22
				23
	530,731		530,731	24
	9,271		9,271	25
	89,594		89,594	26
	-7,812,314		-7,812,314	27
	7,823,030		7,823,030	28
	19		19	29
	2,466		2,466	30
	48		48	31
	134		134	32
	64,604		64,604	33
	1,220,878		1,220,878	34
1,750,236	**6,176,770**	**100,224**	**8,027,230**	

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 2014/Q4

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

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	30,658		30,658	1
	558		558	2
	496		496	3
	992		992	4
				5
	22,802		22,802	6
				7
	4,831		4,831	8
	9,092		9,092	9
	21,270		21,270	10
	42,381		42,381	11
	98		98	12
	8,700		8,700	13
				14
	-36,000		-36,000	15
	74		74	16
	22,365		22,365	17
	129		129	18
	23,242		23,242	19
	11,721		11,721	20
	20,405		20,405	21
		39,349	39,349	22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
1,750,236	**6,176,770**	**100,224**	**8,027,230**	

Schedule Page: 328 Line No.: 1 Column: d
Contract with Avista Corporation Washington Water Power Division expires 01/01/2023.

Schedule Page: 328 Line No.: 2 Column: d
Contract with Avista Corporation Washington Water Power Division expires 01/01/2023.

Schedule Page: 328 Line No.: 4 Column: m
Represents monthly facility usage charges.

Schedule Page: 328 Line No.: 5 Column: d
Contract with Bonneville Power Administration continues until terminated.

Schedule Page: 328 Line No.: 5 Column: m
Represents monthly facility usage charges.

Schedule Page: 328 Line No.: 6 Column: d
Contract with Bonneville Power Administration continues until terminated.

Schedule Page: 328 Line No.: 7 Column: d
Contract with Bonneville Power Administration continues until terminated.

Schedule Page: 328 Line No.: 7 Column: m
Represents monthly facility usage charges.

Schedule Page: 328 Line No.: 8 Column: d
Contract with Bonneville Power Administration continues until terminated.

Schedule Page: 328 Line No.: 8 Column: m
Represents monthly facility usage charges.

Schedule Page: 328 Line No.: 13 Column: d
Represents non-billed redirected MWHs of Cargill Power Markets LLC’s service.

Schedule Page: 328 Line No.: 15 Column: d
Contract with Exelon Generation Company LLC expires 01/01/2034.

Schedule Page: 328 Line No.: 16 Column: d
Contract with Exelon Generation Company LLC expires 01/01/2034.

Schedule Page: 328 Line No.: 30 Column: d
Contract with Morgan Stanley Capital Group Inc expires 01/01/2034.

Schedule Page: 328 Line No.: 31 Column: d
Contract with Morgan Stanley Capital Group Inc expires 01/01/2034.

Schedule Page: 328.1 Line No.: 2 Column: d
Represents non-billed redirected MWHs of Morgan Stanley Capital Group Inc’s service.

Schedule Page: 328.1 Line No.: 6 Column: d
Exchange agreement with PacifiCorp.

Schedule Page: 328.1 Line No.: 6 Column: e
Exchange agreement with Pacificorp. No tariff applicable to exchange agreement.

Schedule Page: 328.1 Line No.: 6 Column: m
Represents monthly facility usage charges.

Schedule Page: 328.1 Line No.: 9 Column: d
Contract with Powerex Corp expires 01/01/2034.

Schedule Page: 328.1 Line No.: 10 Column: d
Contract with Powerex Corp expires 01/01/2034.

Schedule Page: 328.1 Line No.: 12 Column: d
Contract with Powerex Corp expires 01/01/2034.

Schedule Page: 328.1 Line No.: 14 Column: d
Represents non-billed redirected MWHs of Powerex Corp’s service.

Schedule Page: 328.1 Line No.: 16 Column: c
Represents the reassignment of Powerex Corp's transmission capacity rights.

Schedule Page: 328.1 Line No.: 16 Column: d
Represents non-billed redirected MWHs of Powerex Corp’s service.

Schedule Page: 328.1 Line No.: 17 Column: b
Represents the reassignment of Public Utility District No. 1 of Cowlitz County's transmission capacity rights.

Schedule Page: 328.1 Line No.: 17 Column: c

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

Schedule Page: 328.1 Line No.: 17 Column: d

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Schedule Page: 328.1 Line No.: 21 Column: d

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

Schedule Page: 328.1 Line No.: 22 Column: d

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

Schedule Page: 328.1 Line No.: 23 Column: d

Represents non-billed redirected MWHs of Puget Sound Energy’s service.

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

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

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

Contract with Rainbow Energy Marketing Corp expires 01/01/2034.

Schedule Page: 328.1 Line No.: 28 Column: b

Represents the reassignment of Rainbow Energy Marketing Corp.'s transmission capacity rights.

Schedule Page: 328.1 Line No.: 28 Column: c

Represents the reassignment of Rainbow Energy Marketing Corp.'s transmission capacity rights.

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

Represents non-billed redirected MWHs of Rainbow Enery Marketing Corp’s service.

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

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

Schedule Page: 328.1 Line No.: 34 Column: d

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

Schedule Page: 328.2 Line No.: 3 Column: d

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

Schedule Page: 328.2 Line No.: 5 Column: d

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

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

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

Schedule Page: 328.2 Line No.: 10 Column: d

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

Schedule Page: 328.2 Line No.: 11 Column: d

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

Schedule Page: 328.2 Line No.: 14 Column: d

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

Schedule Page: 328.2 Line No.: 22 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.

Schedule Page: 328.2 Line No.: 22 Column: m

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 2014/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 2014/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	Arizona Public Service	NF	579	579		4,002		4,002
2	Avista Corp	NF	6,510	6,510		36,873		36,873
3	Bonneville Power Admin	LFP			62,445,484			62,445,484
4	Bonneville Power Admin	OS					17,838,238	17,838,238
5	Bonneville Power Admin	SFP	135,230	135,230		305,833		305,833
6	Bonneville Power Admin	NF	52,523	52,523		223,991		223,991
7	Columbia River PUD	NF	9	9		4,263		4,263
8	Fale-Safe, Inc	OS					-1,110,728	-1,110,728
9	Idaho Power Company	NF	37,654	37,654		184,579		184,579
10	Los Angeles Dept. Water	NF	764	764		9,166		9,166
11	McMinnville Water & Lig	NF	892	892		8,112		8,112
12	Montana, State of	OS					1,187,554	1,187,554
13	Morgan Stanley	NF	183,600	183,600		282,744		282,744
14	NV Energy	NF	12,732	12,732		103,068		103,068
15	Northwestern Corp	NF	112,714	112,714		604,326		604,326
16	PacifiCorp	OS					103,752	103,752
	TOTAL		560,207	560,207	62,445,484	1,875,058	18,018,816	82,339,358

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 2014/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	PacifiCorp	NF	15,571	15,571		101,926		101,926
2	Puget Sound Energy	NF	160	160		452		452
3	Sacramento Municipal	NF	618	618		4,641		4,641
4	Salt River Project	NF	50	50		178		178
5	Sierra Pacific	NF				-1,505		-1,505
6	WAPA	NF	601	601		2,409		2,409
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		560,207	560,207	62,445,484	1,875,058	18,018,816	82,339,358

Schedule Page: 332 Line No.: 3 Column: b

The Bonneville Power Administration PTP Network contract expires on 12/31/2019. The PTP contract for Rocky Reach expires on 5/31/2015, the PTP contract for John Day and Big Eddy expires on 9/30/2015, and the PTP contract for Vansycle expires on 11/30/2016.

Schedule Page: 332 Line No.: 4 Column: g

Represents Bonneville Power Administration Ancillary Transmission Services.

Schedule Page: 332 Line No.: 8 Column: g

Represents payment for certain Fale-Safe obligations, net of interest income, in exchange for additional access to Intertie.

Schedule Page: 332 Line No.: 12 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.: 16 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 2014/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	1,770,318
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	1,391,205
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	1,594,575
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Involuntary Severance	35,639
7	Diretors Pension	91,757
8	Directors Fees & Expenses	239,519
9	Directors and Officers Expenses	2,205,429
10	Misc Admin Expenses	520,049
11	Colstrip-PPL Montana	469,127
12	Internal & External Reporting	106,504
13	Bull Run PME-Decommissioning	48,840
14	Misc Admin R&D Expenses	9,470
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46	TOTAL	8,482,432

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 2014/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.

Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.

In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.

For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.

4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			25,400,209		25,400,209
2	Steam Production Plant	26,864,548	3,524,192			30,388,740
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	11,847,381	69			11,847,450
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	48,953,920	29,916			48,983,836
7	Transmission Plant	9,806,436	1			9,806,437
8	Distribution Plant	118,339,518	13,150			118,352,668
9	Regional Transmission and Market Operation					
10	General Plant	25,919,140	2,068			25,921,208
11	Common Plant-Electric					
12	TOTAL	241,730,943	3,569,396	25,400,209		270,700,548

B. Basis for Amortization Charges

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 2014/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							
13	Complete data will be						
14	provided in the 2015						
15	Form 1 (5 year						
16	interval).						
17							
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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		215,922	215,922	
2	Docket No. RM06-16				
3					
4	FERC-NERC Reliability		170,986	170,986	
5	Docket No. RM06-22				
6					
7	OPUC-2015 General Rate Case		512,269	512,269	
8	Docket No. UE 283				
9					
10	OPUC matters less than $25,000		216,403	216,403	
11					
12	FERC matters less than $25,000		11,709	11,709	
13					
14	Non Docs matters		155,578	155,578	
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46	TOTAL		1,282,867	1,282,867	

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO			Deferred to Account 182.3	Contra Account	Amount	Deferred in Account 182.3 End of Year	Line No.
Department (f)	Account No. (g)	Amount (h)	(i)	(j)	(k)	(l)	
	928	215,922					1
							2
							3
	928	170,986					4
							5
							6
	928	512,269					7
							8
							9
	928	216,403					10
							11
	928	11,709					12
							13
	928	155,578					14
							15
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		1,282,867					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 2014/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)(a)	Hydroelectric
3	A(1)(b)	Fossil-fuel Steam
4	A(1)(c)	Interanl Combustion or Gas Turbine
5	A(1)(e)	Unconventional Generation
6	A(2)	Electric R, D & D Performed Internally - Transmission
7	A(3)	Electric R, D & D Performed Internally - Distribution
8	A(5)	Electric R, D & D Performed Internally - Environment
9	B(1)	Electric R, D & D Performed Externally
10		Research Support to the Electrical Research Council or EPRI
11		
12		
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26	Totals	
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RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.

4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)

5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.

6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."

7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
60,027		930.2	60,027		3
					4
671,822		930.2	671,822		5
125,000		930.2	125,000		6
283,606		930.2	283,606		7
50,000		930.2	50,000		8
	200,750	930.2	200,750		9
					10
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1,190,455	200,750		1,391,205		26
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

DISTRIBUTION OF SALARIES AND WAGES

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

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	25,828,452		
4	Transmission	3,483,470		
5	Regional Market			
6	Distribution	17,563,943		
7	Customer Accounts	24,812,495		
8	Customer Service and Informational	6,670,609		
9	Sales			
10	Administrative and General	34,210,266		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	112,569,235		
12	Maintenance			
13	Production	11,265,720		
14	Transmission	1,277,632		
15	Regional Market			
16	Distribution	24,078,018		
17	Administrative and General	845,271		
18	TOTAL Maintenance (Total of lines 13 thru 17)	37,466,641		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	37,094,172		
21	Transmission (Enter Total of lines 4 and 14)	4,761,102		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	41,641,961		
24	Customer Accounts (Transcribe from line 7)	24,812,495		
25	Customer Service and Informational (Transcribe from line 8)	6,670,609		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	35,055,537		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	150,035,876	16,520,876	166,556,752
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

DISTRIBUTION OF SALARIES AND WAGES (Continued)

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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)	150,035,876	16,520,876	166,556,752
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	67,341,889	3,981,367	71,323,256
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	67,341,889	3,981,367	71,323,256
72	Plant Removal (By Utility Departments)			
73	Electric Plant	795,523	41,822	837,345
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	795,523	41,822	837,345
77	Other Accounts (Specify, provide details in footnote):			
78	Other Income and Deductions	1,479,815	145,613	1,625,428
79	Co-Owner Shares of Generating Facilities	6,288,144	251,827	6,539,971
80	Other	879,667	3,663,657	4,543,324
81	Payroll Allocated	24,605,162	-24,605,162	
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	33,252,788	-20,544,065	12,708,723
96	TOTAL SALARIES AND WAGES	251,426,076		251,426,076

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 2014/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 2014/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)	1,194,129	1,322,376	416,772	3,135,666
3	Net Sales (Account 447)	6,853,626	6,894,049	8,952,594	30,999,275
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8					
9					
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46	TOTAL	8,047,755	8,216,425	9,369,366	34,134,941

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	46,284	MW	17,058,037	7,731,543	Various	158,232
2	Reactive Supply and Voltage				3,887,442	Various	101,495
3	Regulation and Frequency Response				3,883,413	Various	236,190
4	Energy Imbalance	2,904	MWh	92,803	28,514	MWh	1,252,016
5	Operating Reserve - Spinning				273,110	MWh	65,276
6	Operating Reserve - Supplement				273,110	MWh	65,276
7	Other						
8	Total (Lines 1 thru 7)	49,188		17,150,840	16,077,132		1,878,485

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

Scheduling, System Control and Dispatch	**No of Units**	**Amount**
MW Day	48,524	$3,855
MW Hour	340,996	7,861
MW Month	179	7,861
MW Week	1,578	553
MW Year	3,457,032	112,212
Sum of Peak Demand (KW)	3,883,234	31,515
	7,731,543	**$158,232**

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

Reactive Supply and Voltage	**No of Units**	**Amount**
MW Day	3,772	$47
MW Hour	257	27
MW Month	179	6,874
Sum of Peak Demand (KW)	3,883,234	94,547
	3,887,442	**$101,495**

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

Regulation and Frequency Response	**No of Units**	**Amount**
MW Month	179	$15,579
Sum of Peak Demand (KW)	3,883,234	220,611
	3,883,413	**$236,190**

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	273,110	$65,276

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

Operating Reserve - Supplement	**No of Units**	**Amount**
MW Month	273,110	$65,276

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 2014/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	4,086	10	900	2,588	215	1,250		4,227	97
2	February	4,651	6	1900	3,672	216	1,250		4,381	86
3	March	3,848	11	800	2,717	215	1,250		4,227	
4	Total for Quarter 1	12,585			8,977	646	3,750		12,835	183
5	April	3,762	1	800	2,470	281	1,250		4,227	182
6	May	3,851	14	2100	2,558	317	1,250		4,227	10
7	June	4,071	30	1800	2,588	315	1,250		4,227	31
8	Total for Quarter 2	11,684			7,616	913	3,750		12,681	223
9	July	4,784	28	1800	3,200	253	1,250		4,227	50
10	August	4,657	4	1800	3,288	261	1,250		4,237	75
11	September	3,986	2	2000	2,306	219	1,250		4,239	
12	Total for Quarter 3	13,427			8,794	733	3,750		12,703	125
13	October	4,001	6	2000	2,874		1,250		4,227	22
14	November	4,496	12	1800	3,054	206	1,250		4,302	
15	December	4,517	31	1900	3,341		1,250		4,323	71
16	Total for Quarter 4	13,014			9,269	206	3,750		12,852	93
17	Total Year to Date/Year	50,710			34,656	2,498	15,000		51,071	624

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 2014/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	289	29	300			307			
2	February	292	6	1300			307			
3	March	293	18	2400			307			
4	Total for Quarter 1	874					921			
5	April	298	19	500			307			
6	May	239	3	2300			307			
7	June	176	9	1800			307			
8	Total for Quarter 2	713					921			
9	July	295	15	600			307			
10	August	289	25	300			307			
11	September	291	4	1800			307			
12	Total for Quarter 3	875					921			
13	October	244	12	2300			307			
14	November	291	27	2000			307			
15	December	289	31	1100			307			
16	Total for Quarter 4	824					921			
17	Total Year to Date/Year	3,286					3,684			

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

Long Term Firm Point-to-Point Reservations: Q1

Reservation #	Customer	MW Granted Jan 2014	MW Granted Feb 2014	MW Granted Mar 2014	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	86	86	86	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
76412778	Portland General Electric Company	200	200	200	01/01/2017
77316434	Avista Corp Washington Water Power Division	100	100	100	01/01/2023
77594664	Powerex Inc.	165	165	165	06/01/2018
79072075	Powerex Inc.	10	10	10	01/01/2034
79082732	Portland General Electric Company	10	10	10	01/01/2034
79084421	Exelon Generation Company, LLC	10	10	10	01/01/2034
79091330	Rainbow Energy Marketing Corp.	10	10	10	01/01/2034
79091530	Morgan Stanley Capital Group	10	10	10	01/01/2034
79091653	Public Utility District No. 1 of Klickitat County	11	11	11	01/01/2034
79091680	The Energy Authority, 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
		1,250	**1,250**	**1,250**	

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 2014	MW Granted Feb 2014	MW Granted Mar 2014
79096937	Portland General Electric Company	3,300	-	-
79096947	Portland General Electric Company	200	-	-
79096967	Portland General Electric Company	25	-	-
79097011	Portland General Electric Company	500	-	-
79097012	Portland General Electric Company	200	-	-
79097013	Portland General Electric Company	2	-	-
79241254	Portland General Electric Company	-	3,300	-
79241314	Portland General Electric Company	-	200	200
79241386	Portland General Electric Company	-	25	25
79241394	Portland General Electric Company	-	500	500
79241395	Portland General Electric Company	-	200	200
79241398	Portland General Electric Company	-	2	2
79266282	Puget Sound Energy Marketing	-	96	-
79266502	Transalta Energy Marketing US Inc.	-	58	-
79345291	Portland General Electric Company	-	-	3,300
	Total	**4,227**	**4,381**	**4,227**

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

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 2014	MW Granted May 2014	MW Granted Jun 2014	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
75731986	Puget Sound Energy Marketing	100	100	100	01/01/2017
76412778	Portland General Electric Company	200	200	200	01/01/2017
74566698	Portland General Electric Company	100	100	100	01/01/2022
74382640	Portland General Electric Company	86	86	86	07/01/2017
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
79091330	Rainbow Energy Marketing Corp.	10	10	10	01/01/2034
79091530	Morgan Stanley Capital Group	10	10	10	01/01/2034
79091653	Public Utility District No. 1 of Klickitat County	11	11	11	01/01/2034
79091680	The Energy Authority, 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
		1,250	**1,250**	**1,250**	

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 2014	MW Granted May 2014	MW Granted Jun 2014
79241314	Portland General Electric Company	200	200	200
79241386	Portland General Electric Company	25	25	25
79241394	Portland General Electric Company	500	500	500
79241395	Portland General Electric Company	200	200	200
79241398	Portland General Electric Company	2	2	2
79466549	Portland General Electric Company	3,300	-	-
79601339	Portland General Electric Company	-	3,300	-
79748841	Portland General Electric Company	-	-	3,300
	Total	**4,227**	**4,227**	**4,227**

Schedule Page: 400 Line No.: 8 Column: j

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 2014	MW Granted Aug 2014	MW Granted Sep 2014	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	86	86	86	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
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
79091330	Rainbow Energy Marketing Corp.	10	10	10	01/01/2034
79091530	Morgan Stanley Capital Group	10	10	10	01/01/2034
79091653	Public Utility District No. 1 of Klickitat County	11	11	11	01/01/2034
79091680	The Energy Authority, 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
		1,250	**1,250**	**1,250**	

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 2014	MW Granted Aug 2014	MW Granted Sep 2014
79241314	Portland General Electric Company	200	200	200
79241386	Portland General Electric Company	25	25	25
79241394	Portland General Electric Company	500	500	500
79241395	Portland General Electric Company	200	200	200
79241398	Portland General Electric Company	2	2	2
79828225	Portland General Electric Company	-	10	-
79828261	Portland General Electric Company	-	-	12
79865863	Portland General Electric Company	3,300	-	-
79989358	Portland General Electric Company	-	3,300	-
80131965	Portland General Electric Company	-	-	3,300
	Total	**4,227**	**4,237**	**4,239**

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

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

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

Long Term Firm Point-to-Point Reservations: Q4

Reservation #	Customer	MW Granted Oct 2014	MW Granted Nov 2014	MW Granted Dec 2014	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	86	86	86	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
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
79091330	Rainbow Energy Marketing Corp.	10	10	10	01/01/2034
79091530	Morgan Stanley Capital Group	10	10	10	01/01/2034
79091653	Public Utility District No. 1 of Klickitat County	11	11	11	01/01/2034
79091680	The Energy Authority, 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
		1,250	**1,250**	**1,250**	

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 2014	MW Granted Nov 2014	MW Granted Dec 2014
79241314	Portland General Electric Company	200	200	200
79241386	Portland General Electric Company	25	25	25
79241394	Portland General Electric Company	500	500	500
79241395	Portland General Electric Company	200	200	200
79241398	Portland General Electric Company	2	2	2
80263527	Portland General Electric Company	3,300	-	-
80452960	Puget Sound Energy Marketing	-	75	-
80392584	Portland General Electric Company	-	3,300	-
80494407	Portland General Electric Company	-	-	3,300
80647688	Puget Sound Energy Marketing	-	-	96
	Total	**4,227**	**4,302**	**4,323**

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

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:
These entries are the "Transmission Provider's Monthly Transmission System Peak" as

defined in PGE's OATT in Section 1.47, the maximum firm usage of PGE's 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 2014	MW Granted Feb 2014	MW Granted Mar 2014	Earliest Termination Date
76059414	Portland General Electric Co.	307	307	307	7/1/2022

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

Monthly Peak MW:
These entries are the "Transmission Provider's Monthly Transmission System Peak" as defined in PGE's OATT in Section 1.47, the maximum firm usage of PGE's transmission system during the calendar month.

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

Long Term Firm Point-to-Point Reservations: Q1

Reservation #	Customer	MW Granted Apr 2014	MW Granted May 2014	MW Granted Jun 2014	Earliest Termination Date
76059414	Portland General Electric Co.	307	307	307	7/1/2022

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

Monthly Peak MW:
These entries are the "Transmission Provider's Monthly Transmission System Peak" as defined in PGE's OATT in Section 1.47, the maximum firm usage of PGE's transmission system during the calendar month.

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

Long Term Firm Point-to-Point Reservations: Q1

Reservation #	Customer	MW Granted Jul 2014	MW Granted Aug 2014	MW Granted Sep 2014	Earliest Termination Date
76059414	Portland General Electric Co.	307	307	307	7/1/2022

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

Monthly Peak MW:
These entries are the "Transmission Provider's Monthly Transmission System Peak" as defined in PGE's OATT in Section 1.47, the maximum firm usage of PGE's transmission system during the calendar month.

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

Long Term Firm Point-to-Point Reservations: Q1

Reservation #	Customer	MW Granted Oct 2014	MW Granted Nov 2014	MW Granted Dec 2014	Earliest Termination Date
76059414	Portland General Electric Co.	307	307	307	7/1/2022

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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									

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 2014/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	17,603,187
3	Steam	4,465,664			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	
5	Hydro-Conventional	1,750,572			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	3,476,895
7	Other	4,601,085			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	10,817,321	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	26,472
10	Purchases	11,392,970	27	Total Energy Losses	1,287,491
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	22,394,045
12	Received	454,243			
13	Delivered	452,897			
14	Net Exchanges (Line 12 minus line 13)	1,346			
15	Transmission For Other (Wheeling)				
16	Received	6,762,016			
17	Delivered	6,579,608			
18	Net Transmission for Other (Line 16 minus line 17)	182,408			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	22,394,045			

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 2014/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	1,888,084	111,684	3,264	27	19
30	February	1,762,642	133,078	3,866	6	19
31	March	1,822,691	278,269	2,917	11	8
32	April	1,647,872	243,522	2,671	1	8
33	May	1,646,624	242,958	2,944	14	18
34	June	1,630,794	251,523	2,828	30	19
35	July	2,086,167	450,952	3,528	16	18
36	August	2,200,486	560,015	3,646	11	16
37	September	1,934,472	476,898	3,048	6	18
38	October	1,801,205	341,200	2,896	6	18
39	November	1,912,111	302,953	3,406	13	18
40	December	1,878,489	131,717	3,477	30	19
41	TOTAL	22,211,637	3,524,769			

Schedule Page: 401 Line No.: 7 Column: b

In addition to the generation from the Beaver, Port Westward 1, Port Westward 2, and Coyote Springs generation plants, as shown on page 403, Other Generation includes 1,171,899 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 1,174,091 megawatt hours.

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

In-service production cost at 12/31/2014:	$922,030,681
Total installed capacity:	450 megawatts
Operations and maintenance expenses for 2014:	$21,348,799

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

In-service production cost at 12/31/2014	$461,380,520
Total installed capacity:	267 megawatts
Operations and maintenance expenses for 2014:	$114,190

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 2014, 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 2014 to FERC 584.1 - Operation of Energy Storage Equipment ($22,643) and FERC 592.2 - Maintenance of Energy Storage Equipment ($55,231). Line loss includes 1 MWh of Energy stored in this battery at year end.

Schedule Page: 401 Line No.: 40 Column: c

Line Losses associated with Sales for Resale have been estimated. This note applies to column (c), lines 29 - 40.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: Boardman (b)			Plant Name: Boardman (PGE Share) (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	1980			1980		
4	Year Last Unit was Installed	1980			1980		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	642.20			577.90		
6	Net Peak Demand on Plant - MW (60 minutes)	602			0		
7	Plant Hours Connected to Load	6586			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	112			0		
12	Net Generation, Exclusive of Plant Use - KWh	3156002000			2539107000		
13	Cost of Plant: Land and Land Rights	939463			832853		
14	Structures and Improvements	153125738			140717275		
15	Equipment Costs	573361223			509882149		
16	Asset Retirement Costs	42531987			38183765		
17	Total Cost	769958411			689616042		
18	Cost per KW of Installed Capacity (line 17/5) Including	1198.9387			1193.3138		
19	Production Expenses: Oper, Supv, & Engr	2813003			2025643		
20	Fuel	80763450			63848815		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	5956318			4604011		
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	10264791			8236250		
27	Rents	0			0		
28	Allowances	113328			113328		
29	Maintenance Supervision and Engineering	880559			608784		
30	Maintenance of Structures	647531			517124		
31	Maintenance of Boiler (or reactor) Plant	2531412			2035252		
32	Maintenance of Electric Plant	20999605			16819142		
33	Maintenance of Misc Steam (or Nuclear) Plant	222308			176573		
34	Total Production Expenses	125192305			98984922		
35	Expenses per Net KWh	0.0397			0.0390		
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	1853491	17606	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	8517	138690	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	42.352	122.432	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	37.175	126.339	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	2.182	21.689	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.018	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	8456.700	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 2014/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			1926557000		
13	Cost of Plant: Land and Land Rights	0			3328862		
14	Structures and Improvements	0			115099738		
15	Equipment Costs	0			333678011		
16	Asset Retirement Costs	0			-293784		
17	Total Cost	0			451812827		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			1451.8407		
19	Production Expenses: Oper, Supv, & Engr	0			235396		
20	Fuel	0			31279450		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			2048422		
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			1998365		
27	Rents	0			60036		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			546159		
30	Maintenance of Structures	0			951206		
31	Maintenance of Boiler (or reactor) Plant	0			5900483		
32	Maintenance of Electric Plant	0			2873310		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			827370		
34	Total Production Expenses	0			46720197		
35	Expenses per Net KWh	0.0000			0.0243		
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

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Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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
		465			409			271	6
		1694			5543			5969	7
		0			0			0	8
		533			415			270	9
		0			0			0	10
		49			24			29	11
		214128000			1941064000			1273555000	12
		0			0			0	13
		32713232			41227746			11087356	14
		181800345			222634871			175533462	15
		-617406			231072			113193	16
		213896171			264093689			186734011	17
		350.1329			546.4384			688.5472	18
		158529			516610			1222090	19
		13821329			87922568			49822640	20
		0			0			0	21
		0			0			0	22
		0			0			0	23
		0			0			0	24
		1972721			2314691			1097774	25
		2425396			1789137			736313	26
		175220			33680			72382	27
		0			0			0	28
		1184455			212079			95296	29
		253207			66474			42738	30
		0			0			0	31
		3648396			7299232			5344422	32
		182404			48133			11653	33
		23821657			100202604			58445308	34
		0.1112			0.0516			0.0459	35
Gas	Oil		Gas	Oil		Gas	Oil		36
Mcf's	Barrels		Mcf's	Barrels		Mcf's	Barrels		37
2032360	855	0	13732986	0	0	9729335	0	0	38
1019000	138690	0	1019000	138690	0	1019000	138690	0	39
2.350	0.000	0.000	4.207	0.000	0.000	3.881	0.000	0.000	40
6.767	78.755	0.000	6.402	0.000	0.000	5.121	0.000	0.000	41
6.638	13.546	0.000	6.280	0.000	0.000	5.024	0.000	0.000	42
0.064	0.000	0.000	0.045	0.000	0.000	0.039	0.000	0.000	43
9675.200	0.000	0.000	7202.200	0.000	0.000	7766.300	0.000	0.000	44

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Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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: (e)	Plant Name: (f)	Line No.
Reciprocating Engine			1
Outdoor			2
2014			3
2014			4
206.30	0.00	0.00	5
118	0	0	6
13	0	0	7
0	0	0	8
205	0	0	9
0	0	0	10
0	0	0	11
439000	0	0	12
0	0	0	13
28387889	0	0	14
242549819	0	0	15
647461	0	0	16
271585169	0	0	17
1316.4574	0	0	18
0	0	0	19
72804	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
12343	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
191	0	0	32
0	0	0	33
85338	0	0	34
0.1944	0.0000	0.0000	35

									Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	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.

In 1985, PGE sold a 15% undivided interest in the Boardman Plant and a 10.714% undivided interest in the Company's share of the Pacific Northwest Intertie transmission line (jointly, the Facility Assets) to an unrelated third party (Purchaser). Under the terms of the original 1985 agreements, on December 31, 2013, PGE acquired the Facility Assets from the Purchaser in exchange for $1 from the Purchaser. This transaction was approved by the FERC on December 19, 2013 through Docket EC14-13-000.

The original cost of the 15% of the Boardman Plant and the 10.714% undivided interest in the Company's share of the Pacific Northwest Intertie transmission line at December 31, 2013 was estimated at $96 million and $2 million, respectively. It was also estimated that these assets were fully depreciated at the time the acquisition was executed since it coincided with the expiration of various agreements under the terms of the original 1985 transaction.

The proposed final accounting entries associated with this transaction were submitted to the FERC on June 27, 2014, in compliance with the accounting under the Uniform System of Accounts (Docket AC14-129-000). On September 29, 2014, FERC approved the final proposed journal entries. In September 2014, the final accounting entries were executed, which increased both Electric plant in service (Account 101) and Accumulated provision for depreciation (Account 108) by $97,861,971 (Steam $94,061,144 and Transmission $3,800,827) with corresponding offsets to Electric plant purchased or sold (Account 102).

In December 2014 PGE acquired an additional 10% undivided interest from another co-owner in the Boardman Plant, and associated equipment and facilities, as well as certain contracts and other rights related to that co-owner's ownership interest in the Boardman Plant.

The original cost of the 10% share of the assets acquired at December 31, 2014 was estimated at $67 million.

On September 19, 2014, PGE filed an application requesting authorization for the acquisition of the rights, titles, and interests associated with this transaction pursuant to section 203(a)(1) of the Federal Power Act (FPA), including proposed accounting entries. On November 14, 2014, the FERC concluded that the proposed transaction was consistent with public interest and authorized the transaction (Docket EC14-147-000). In December 2014, accounting entries were executed which increased Electric plant in service (Account 101) by $67,211,321 (Steam Plant $65,882,727 and Transmission $1,328,594), Accumulated provision for depreciation (Account 108) by $47,707,066 (Steam $46,764,020 and Transmission $943,046), and Construction work in progress (Account 107) by $372,000 with corresponding offsets to Electric plant acquisition adjustments (Account 114).

In accordance with Electric Plant Instruction No. 5 of the Uniform System of Accounts and Electric plant purchased or sold (Account 102), PGE will submit final accounting entries within six months of the date that the proposed transaction was authorized by the FERC.

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, 2014, as appropriate. Details are reported in Page 402 col (b).

In 1985, PGE sold a 15% undivided interest in the Boardman Plant and a 10.714% undivided interest in the Company's share of the Pacific Northwest Intertie transmission line (jointly, the Facility Assets) to an unrelated third party (Purchaser). Under the terms of the original 1985 agreements, on December 31, 2013, PGE acquired the Facility Assets from the Purchaser in exchange for $1 from the Purchaser. This transaction was approved by the FERC on December 19, 2013 through Docket EC14-13-000.

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In accordance with Electric Plant Instruction No. 5 of the Uniform System of Accounts and Electric plant purchased or sold (Account 102), PGE will submit final accounting entries within six months of the date that the proposed transaction was authorized by the FERC.

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 Line No.: 28 Column: b

Represents PGE only SO2 Allowance Expense reported in FERC Account 509 Allowances.

Schedule Page: 402.1 Line No.: -1 Column: c

Jointly owned. PP&L 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: d

On December 30, 2014 the Port Westward 2 Plant was declared in-service and commercially operable to PGE as of this date. The Plant uses 12 natural gas-fired reciprocating engines.

Schedule Page: 402 Line No.: 44 Column: b2

The Boardman Coal Plant does not use oil for generation. Oil is used during startup or setup conditions and other temporary operating conditions.

Schedule Page: 402 Line No.: 44 Column: d1

The Beaver Plant uses gas extensively for generation with minimal oil usage. The Average BTU per KWh Net Generation reported is a composite heat rate for both fuels.

Schedule Page: 402 Line No.: 44 Column: e1

The Port Westward 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.

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	8,759
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	46
12	Net Generation, Exclusive of Plant Use - Kwh	0	160,974,000
13	Cost of Plant		
14	Land and Land Rights	0	33,434
15	Structures and Improvements	0	6,486,039
16	Reservoirs, Dams, and Waterways	0	25,580,414
17	Equipment Costs	0	9,638,287
18	Roads, Railroads, and Bridges	0	1,976,298
19	Asset Retirement Costs	0	90
20	TOTAL cost (Total of 14 thru 19)	0	43,714,562
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	1,187.8957
22	Production Expenses		
23	Operation Supervision and Engineering	0	97,285
24	Water for Power	0	62,016
25	Hydraulic Expenses	0	470,269
26	Electric Expenses	0	188,816
27	Misc Hydraulic Power Generation Expenses	0	1,337,892
28	Rents	0	142,154
29	Maintenance Supervision and Engineering	0	396,565
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	422,973
32	Maintenance of Electric Plant	0	424,307
33	Maintenance of Misc Hydraulic Plant	0	565,164
34	Total Production Expenses (total 23 thru 33)	0	4,107,441
35	Expenses per net KWh	0.0000	0.0255

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Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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)	114	0
7	Plant Hours Connect to Load	7,585	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	422,526,000	281,698,000
13	Cost of Plant		
14	Land and Land Rights	3,672,025	2,448,139
15	Structures and Improvements	8,908,961	5,933,344
16	Reservoirs, Dams, and Waterways	15,523,560	10,572,546
17	Equipment Costs	10,068,283	6,696,030
18	Roads, Railroads, and Bridges	3,219,852	2,151,533
19	Asset Retirement Costs	52	52
20	TOTAL cost (Total of 14 thru 19)	41,392,733	27,801,644
21	Cost per KW of Installed Capacity (line 20 / 5)	376.9830	379.8039
22	Production Expenses		
23	Operation Supervision and Engineering	223,110	146,204
24	Water for Power	156,011	87,868
25	Hydraulic Expenses	2,161,281	1,578,986
26	Electric Expenses	204,554	143,931
27	Misc Hydraulic Power Generation Expenses	469,218	247,760
28	Rents	14,402	6,878
29	Maintenance Supervision and Engineering	84,568	51,195
30	Maintenance of Structures	1,781	1,781
31	Maintenance of Reservoirs, Dams, and Waterways	37,436	37,436
32	Maintenance of Electric Plant	308,060	58,693
33	Maintenance of Misc Hydraulic Plant	146,347	51,135
34	Total Production Expenses (total 23 thru 33)	3,806,768	2,411,867
35	Expenses per net KWh	0.0090	0.0086

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	80	6
8,595	8,757	8,623	7
			8
58	25	44	9
7	4	19	10
0	0	6	11
204,604,000	104,996,000	209,159,000	12
			13
377,100	86,408	9,457	14
8,472,478	2,930,004	7,166,089	15
30,878,567	53,922,488	22,511,077	16
8,339,563	8,562,940	9,471,959	17
2,591,397	458,019	2,322,130	18
6	64	2,122	19
50,659,111	65,959,923	41,482,834	20
1,241.6449	3,201.9380	813.3889	21
			22
63,103	49,607	64,251	23
48,744	40,332	52,788	24
941,636	140,847	842,179	25
128,195	140,062	162,066	26
248,541	241,178	600,460	27
36,640	0	541,235	28
120,665	48,100	-244,343	29
0	0	512	30
469,765	42,203	106,261	31
58,814	165,869	88,304	32
191,149	135,489	154,391	33
2,307,252	1,003,687	2,368,104	34
0.0113	0.0096	0.0113	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 2014/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
324.90	216.60	15.40	5
298	0	18	6
7,970	0	8,646	7
			8
345	0	18	9
192	0	7	10
35	0	1	11
992,592,000	661,761,000	127,380,000	12
			13
3,726,481	2,521,011	572,077	14
16,235,873	10,779,154	9,367,427	15
170,250,725	111,716,127	23,568,353	16
30,468,411	20,395,849	13,821,957	17
2,053,479	1,384,448	0	18
165	165	2,630	19
222,735,134	146,796,754	47,332,444	20
685.5498	677.7320	3,073.5353	21
			22
267,312	173,316	36,291	23
298,321	215,035	33,408	24
1,721,156	1,009,462	111,033	25
222,334	148,240	112,913	26
1,007,503	736,831	221,015	27
35,767	26,570	0	28
138,477	97,688	54,178	29
6,163	6,163	0	30
668,254	668,254	110,114	31
640,917	336,136	218,643	32
489,325	372,955	92,258	33
5,495,529	3,790,650	989,853	34
0.0055	0.0057	0.0078	35

Schedule Page: 406.1 Line No.: -2 Column: b

Respondent is the principal owner (66.67% interest) and operator of the Pelton Plant. The other owner is the Confederated Tribes of the Warm Springs Reservation of Oregon.
Reported here are 100% costs and plant statistics, including shared and non-shared costs.

Schedule Page: 406.1 Line No.: -2 Column: c

Jointly owned. Installed capacity on line 5 represents 66.67% share. Details reported on Page 406.1, column (b). Reported here are respondent's 66.67% share of cost of plant, net generation and production expenses.

Schedule Page: 406.1 Line No.: -2 Column: d

Respondent is the principal owner (66.67% interest) and operator of the Round Butte Plant. The other owner is the Confederated Tribes of the Warm Springs Reservation of Oregon.
Reported here are 100% costs and plant statistics, including shared and non-shared costs.

Schedule Page: 406.1 Line No.: -2 Column: e

Jointly owned. Installed capacity on line 5 represents 66.67% share. Details reported on Page 407.1, column (d). Reported here are respondent's 66.67% share of cost of plant, net generation and production expenses.

Schedule Page: 406.1 Line No.: 5 Column: e

The Round Butte Hydro plant name plate rating has changed from 184.80-MW to 216.60-MW due to efficiencies from the rewind of generator unit #3.

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 2014/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 2014/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.
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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	1	104,631
2	Oregon Military Dept/A.F.R.C	2001	1.60	1.6	25	164,147
3	US Bank Corp Columbia Center	2001	6.40	6.2	135	488,058
4	Portland State University	2004	2.80	2.8	4	261,732
5	Oregon Military Joint Forces HQ	2005	1.60	1.6	25	191,439
6	Stimson Lumber	2005	0.57	0.5	6	159,546
7	FORTIX (ViaWest)	2005	8.50	7.7	147	515,393
8	Skyline	2005	2.00	1.8	29	201,526
9	Tri-Quint	2005	0.60	0.5	4	109,968
10	NCCWC- Filter Plant	2005	2.00	1.8	28	122,958
11	PCC Structurals	2005	1.00	0.9	12	113,874
12	Providence Portland Medical Center	2005	6.00	5.4	77	265,383
13	Salem Hospital	2006	4.00	3.6	58	188,494
14	Sunrise Water Authority Pump Station	2006	1.25	1.1	14	88,272
15	Providence Newberg Hospital	2006	1.50	1.4	21	156,833
16	Sungard DSG	2006	2.00	1.8	32	331,845
17	Kaiser Sunnyside Hospital	2007	4.50	4.0	87	352,752
18	Newberg Waste Water Treatment Plant	2008	2.00	1.8	26	154,458
19	Xerox Corp	2007	4.00	3.6	49	380,259
20	Newberg Water Treatment Plant	2007	1.00	0.9	15	78,159
21	MEMC (Solaicx)	2008	1.00	0.9	13	62,963
22	Solar World	2008	3.00	2.7	31	219,984
23	Oregon Dept of Admin Serv - Data Center	2010	2.00	1.8	4	277,254
24	Sanyo	2010	1.00	0.9	12	43,144
25	Sysco Foods	2010	2.00	1.8	29	191,386
26	Clackamas Intertie 2	2012	0.60	0.5	8	135,045
27	Dawson Creek	2012	0.80	0.7	11	95,706
28	Kaiser Westside Hospital	2012	4.00	3.6	61	408,815
29	North Plains Pump Station	2012	0.80	0.7	12	53,132
30	Oak Lodge Sanitary District	2012	2.00	1.8	29	229,144
31	Oregon Dept of Admin Serv - Revenue Bldg	2012	1.50	1.4	18	284,255
32	Oregon State Hospital	2012	4.00	3.6	69	172,879
33	Portland Service Center	2012	0.50	0.5	8	322,698
34	Sandy Highschool	2012	1.25	1.1	15	179,894
35	TATA Communications - Hillsboro	2012	4.50	3.3	12	328,979
36	Tri-City Wastewater Treatment Plant	2012	2.50	2.3	35	161,695
37	TATA Communications - Portland	2013	6.60	5.9	32	612,983
38	City of Hillsboro Crandall Reservoir	2013	0.80	0.7	7	105,307
39	East County Courts	2013	1.50	1.4	20	316,848
40	City of Portland-Columbia Blvd WWTP	2013	1.00	0.9	15	160,271
41	Food Services of America	2013	2.00	1.8	6	221,986
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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	6	263,775
2	Carver (Readiness Center) DSG	2014	2.00	1.8	17	818,159
3	Juvenile Justice Center	2014	0.70	0.8	4	171,334
4	Clackamas River Water DSG	2014	2.00	1.8	15	375,089
5	SunWay 1	2014	0.10	0.1		42,650
6	Total					10,685,102
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GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
209,263			25,557	diesel-low s	2,376	1
102,592		5,362	12,839	diesel-low s	2,386	2
76,259		45,001	116,819	diesel-low s	1,636	3
93,476			100,856	diesel-low s	2,643	4
119,650			36,233	diesel-low s	2,389	5
282,382		1,608	15,521	diesel-low s	2,348	6
60,635		32,732	48,194	diesel-low s	2,215	7
100,763		7,563	30,875	diesel-low s	1,663	8
183,279		1,237	4,381	diesel-low s	2,457	9
61,479		5,670	11,843	diesel-low s	2,284	10
113,874		1,772	5,984	diesel-low s	2,077	11
44,231			32,162	diesel-low s	2,571	12
47,124		35,224	33,637	diesel-low s	2,306	13
70,617			20,580	diesel-low s	2,389	14
104,555		14,553	19,164	diesel-low s	2,349	15
165,922		4,428	7,207	diesel-low s	1,833	16
78,389		18,643	135,261	diesel-low s	1,893	17
77,229			14,980	diesel-low s	2,389	18
95,065		10,145	23,499	diesel-low s	2,179	19
78,159			11,448	diesel-low s	2,389	20
62,963		2,625	46,589	diesel-low s	2,342	21
73,328		7,471	-6,496	diesel-low s	1,893	22
138,627			612	diesel-low s	2,389	23
43,144		4,243	79,647	diesel-low s	2,021	24
95,693		6,758	9,857	diesel-low s	1,918	25
225,075		2,412		diesel-low s	2,064	26
119,632		4,960	9,456	diesel-low s	2,286	27
102,204		28,359	33,070	diesel-low s	2,060	28
66,415		2,514	8,780	diesel-low s	2,618	29
114,572			13,064	diesel-low s	2,478	30
189,503		3,997	6,293	diesel-low s	2,111	31
43,220		36,794	24,138	diesel-low s	2,336	32
645,396			13,780	diesel-low s	2,336	33
143,915		4,326	7,974	diesel-low s	2,241	34
73,106			37,593	diesel-low s	2,336	35
64,678		4,269	37,463	diesel-low s	2,386	36
92,876			51,925	diesel-low s	2,334	37
131,634			40	diesel-low s	2,332	38
211,232			7,406	diesel-low s	2,276	39
160,271		2,949	14,650	diesel-low s	2,276	40
110,993		3,936	8,957	diesel-low s	2,198	41
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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.
329,719			6,644	diesel-low s	2,192	1
409,080			20,979	diesel-low s	2,192	2
228,445			7,617	diesel-low s	2,192	3
187,545			1,459	diesel-low s	2,192	4
426,497				solar		5
		299,551	1,148,537			6
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2014/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						
7	BOARDMAN	BPA SLATT	500.00	500.00	ST. TOWER	17.83		1
8	COYOTE SPRINGS	BPA SLATT	500.00	500.00				2
9	COLSTRIP PROJECT:							
10	COLSTRIP SWYD.	BROADVIEW 'A'	500.00	500.00	ST. TOWER		112.30	1
11	COLSTRIP SWYD.	BROADVIEW 'B'	500.00	500.00	ST. TOWER		115.80	1
12	BROADVIEW SWYD.	TOWNSEND 'A'	500.00	500.00	ST. TOWER		133.40	1
13	BROADVIEW SWYD.	TOWNSEND 'B'	500.00	500.00	ST. TOWER		133.40	1
14	Colstrip Project Costs	Project Lines						
15	Tot 500KV Line Expenses							
16								
17	BIGLOW CANYON WF	JOHN DAY	230.00	230.00				1
18	TUCANNON WF	CENTRAL FERRY BPA	230.00	230.00	H-WOOD	20.70		1
19								
20	PELTON 230KV PROJECT							
21	PELTON	ROUND BUTTE	230.00	230.00	H-WOOD	7.87		1
22								
23	NON PROJECT 230KV:							
24	BETHEL	ROUND BUTTE	230.00	230.00	H-WOOD	53.85		1
25			230.00	230.00	ST. TOWER	44.85		1
26	ROUND BUTTE	BPA REDMOND	230.00	230.00	H-WOOD	23.58		1
27	BETHEL	BPA TIE (SANTIAM)	230.00	230.00	H-WOOD	3.64		1
28	BETHEL	McLOUGHLIN	230.00	230.00	H-WOOD	35.57		1
29	CARVER	GRESHAM	230.00	230.00	H-WOOD	7.17		1
30	McLOUGHLIN	CARVER #1	230.00	230.00	H-WOOD	4.95		1
31	McLOUGHLIN	CARVER #2	230.00	230.00	ST. MONOP	4.88		1
32	BPA KEELER	ST. MARY'S W.	230.00	230.00	H-WOOD	2.89		1
33			230.00	230.00	ST. TOWER	3.78		2
34	BLUE LAKE	TROUTDALE BPA	230.00	230.00	H-WOOD	0.84		1
35			230.00	230.00	ST. MONOP	0.58		1
36					TOTAL	610.46	536.65	58

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	PEARL BPA	SHERWOOD	230.00	230.00	ST. TOWER		4.72	2
2			230.00	230.00	ST. TOWER	0.16		1
3	GRESHAM	LINNEMAN	230.00	230.00	ST. TOWER	0.31		1
4	McLOUGHLIN	SHERWOOD	230.00	230.00	ST. TOWER	11.51		1
5			230.00	230.00	H-TOWER	0.60		1
6	NON PROJECT 230KV							
7	McLOUGHLIN	SHERWOOD	230.00	230.00	ST. TOWER		4.40	2
8	ST. MARY'S W.	MURRAYHILL	230.00	230.00	ST. TOWER	5.92		1
9	HORIZON	KEELER BPA	230.00	230.00	ST. MONOP	1.47		1
10	MURRAYHILL	SHERWOOD	230.00	230.00	ST. TOWER	5.68		2
11	PORT WESTWARD	TROJAN #1	230.00	230.00	ST. MONOP	18.78		1
12	PORT WESTWARD	TROJAN #2	230.00	230.00	ST. MONOP	9.39		1
13	TROJAN	ST. MARY'S W.	230.00	230.00	H-WOOD	0.10		1
14			230.00	230.00	ST. TOWER	8.07		1
15					ST.TOWER		32.20	1
16	TROJAN	RIVERGATE	230.00	230.00	ST. TOWER	32.20		2
17			230.00	230.00	ST. TOWER	2.88		2
18								
19	Tot Nonproj 230kv Costs							
20								
21	GRESHAM	TROUTDALE BPA	230.00	230.00	ST. TOWER		0.43	1
22	BOARDMAN	PPL DALREED	230.00	230.00	H-WOOD	16.76		1
23								
24	Tot 230KV LINE EXPENSES							
25								
26	PROJECT 115 KV LINES							
27	FARADAY	MCLOUGHLIN	115.00	115.00	H-WOOD	14.70		1
28	NORTH FORK	FARADAY	115.00	115.00	H-WOOD	2.79		1
29	OAK GROVE	FARADAY	115.00	115.00	DC LATTICE	18.68		2
30	OAK GROVE	MCLOUGHLIN	115.00	115.00	H-WOOD	14.70		2
31			115.00	115.00	DC LATTICE	18.68		2
32	Tot 115KV LINE EXPENSES							
33								
34								
35								
36					TOTAL	610.46	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 2014/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		5,883,809	5,883,809					7
		3,624,934	3,624,934					8
								9
								10
								11
								12
								13
	1,194,326	43,101,062	44,295,388					14
				1,625,172	551,602	800,231	2,977,005	15
								16
		3,040,852	3,040,852					17
795KCMAAC		2,031,709	2,031,709					18
								19
				434,669	147,532	247,970	830,171	20
795MCMACSR	7,579	298,654	306,233					21
								22
								23
1272MCMACSR								24
1272MCMACSR								25
795MCMACSR								26
795MCMACSR								27
1272MCMACSR								28
1272MCMAAC								29
1272MCMAAC								30
1272MCMACSS								31
1590MCMACSRTW								32
1590MCMACSRTW								33
1780MCMACSR								34
								35
	10,565,024	149,015,051	159,580,075	2,059,841	699,134	1,118,820	3,877,795	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 2014/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.
2388MCMAACTW								1
2388MCMAACTW								2
1272MCMAAC								3
1272MCMAAC								4
1780MCMACSR								5
								6
1272MCMAAC								7
1272MCMAAC								8
1272MCMACSS								9
1272MCMAAC								10
2156MCMACSS								11
2156MCMACSS								12
1272MCMAAC								13
1590MCMAAC								14
1590MCMAAC								15
1590MCMAAC								16
1272MCMACSR								17
								18
	8,875,815	67,649,098	76,524,913					19
								20
954KCMACSR								21
795KCMAAC		1,074,170	1,074,170					22
								23
								24
								25
								26
795KCMACSR		871,841	871,841					27
556KCMACSR	120,248	621,351	741,599					28
250CU	12,477	503,937	516,414					29
795KCMACSR								30
250CU	22,295	884,661	906,956					31
						70,619	70,619	32
								33
								34
								35
	10,565,024	149,015,051	159,580,075	2,059,841	699,134	1,118,820	3,877,795	36

Schedule Page: 422 Line No.: 3 Column: a

In 1985, PGE sold a 15% undivided interest in the Boardman Plant and a 10.714% undivided interest in the Company's share of the Pacific Northwest Intertie transmission line (jointly, the Facility Assets) to an unrelated third party (Purchaser). Under the terms of the original 1985 agreements, on December 31, 2013, PGE acquired the Facility Assets from the Purchaser in exchange for $1 from the Purchaser. This transaction was approved by the FERC on December 19, 2013 through Docket EC14-13-000.

The original cost of the 15% of the Boardman Plant and the 10.714% undivided interest in the Company's share of the Pacific Northwest Intertie transmission line at December 31, 2013 was estimated at $96 million and $2 million, respectively. It was also estimated that these assets were fully depreciated at the time the acquisition was executed since it coincided with the expiration of various agreements under the terms of the original 1985 transaction.

The proposed final accounting entries associated with this transaction were submitted to the FERC on June 27, 2014, in compliance with the accounting under the Uniform System of Accounts (Docket AC14-129-000). On September 29, 2014, FERC approved the final proposed journal entries. In September 2014, the final accounting entries were executed, which increased both Electric plant in service (Account 101) and Accumulated provision for depreciation (Account 108) by $97,861,972 (Steam $94,061,144 and Transmission $3,800,827) with corresponding offsets to Electric plant purchased or sold (Account 102).

In December 2014 PGE acquired an additional 10% undivided interest from another co-owner in the Boardman Plant, and associated equipment and facilities, as well as certain contracts and other rights related to that co-owner's ownership interest in the Boardman Plant.

The original cost of the 10% share of the assets acquired at December 31, 2014 was estimated at $67 million.

On September 19, 2014, PGE filed an application requesting authorization for the acquisition of the rights, titles, and interests associated with this transaction pursuant to section 203(a)(1) of the Federal Power Act (FPA), including proposed accounting entries. On November 14, 2014, the FERC concluded that the proposed transaction was consistent with public interest and authorized the transaction (Docket EC14-147-000). In December 2014, accounting entries were executed which increased Electric plant in service (Account 101) by $67,211,321 (Steam Plant $65,882,727 and Transmission $1,328,594), Accumulated provision for depreciation (Account 108) by $47,707,066 (Steam $46,764,020 and Transmission $943,046), and Construction work in progress (Account 107) by $372,000 with corresponding offsets to Electric plant acquisition adjustments (Account 114).

In accordance with Electric Plant Instruction No. 5 of the Uniform System of Accounts and Electric plant purchased or sold (Account 102), PGE will submit final accounting entries within six months of the date that the proposed transaction was authorized by the FERC.

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

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

Schedule Page: 422 Line No.: 8 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.: 9 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.: 15 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.: 17 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.: 21 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.: 1 Column: a

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

Schedule Page: 422.1 Line No.: 21 Column: a

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

Schedule Page: 422.1 Line No.: 22 Column: a

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

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 2014/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	TUCANNON WF	CENTRAL FERRY SUB,BPA	20.70	H-WOOD			
2	PORT WESTWARD	TROJAN #2	9.39	H-WOOD			
3							
4							
5							
6							
7							
8							
9							
10							
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41							
42							
43							
44	TOTAL		30.09				

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	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
954	ACSR		230		1,015,854	1,015,855		2,031,709	1
2156	ACSS		230		1,225,331	2,292,143		3,517,474	2
									3
									4
									5
									6
									7
									8
									9
									10
									11
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					2,241,185	3,307,998		5,549,183	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	/ /	2014/Q4

FOOTNOTE DATA

Schedule Page: 424 Line No.: 2 Column: a

Represents costs for the upgrading of structures and the reconductoring to 2156MCM ACSS wire. Approximately 9 miles of the Port Westward to Trojan#2 230-kV transmission line.

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 2014/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	12.50	
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 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 2014/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	12.50	
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	57.00	13.00	

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 2014/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Midway, near Portland, OR	Distrib./unattended	115.00	13.00	
2	Mill Creek, near Salem, OR	Distrib./unattended	115.00	13.00	
3	Mobile sub No. 1, OR	Distrib./unattended	115.00	57.00	13.00
4	Mobile sub No. 2, OR	Distrib./unattended	115.00	57.00	13.00
5	Mobile Sub No. 3, OR	Distrib./unattended	115.00	57.00	12.50
6	Mobile Sub No. 4, OR	Distrib./unattended	115.00	57.00	13.00
7	Molalla, Molalla, OR	Distrib./unattended	57.00	13.00	
8	Mt. Angel, Mt. Angel, OR	Distrib./unattended	57.00	13.00	
9	Mt. Pleasant, Oregon City, OR	Distrib./unattended	115.00	13.00	
10	Multnomah, Portland, OR	Distrib./unattended	115.00	13.00	
11	Newberg, Newberg, OR	Distrib./unattended	115.00	13.00	
12	North Marion, near Woodburn, OR	Distrib./unattended	57.00	13.00	
13	North Plains, North Plains, OR	Distrib./unattended	57.00	13.00	
14	Northern, Portland, OR	Distrib./unattended	57.00	11.00	
15	Oak Hills, near Beaverton, OR	Distrib./unattended	115.00	13.00	
16	Oregon City - BPA, near Wilsonville, OR	Distrib./unattended	57.00		
17	Orenco, near Hillsboro, OR	Distrib./unattended	115.00	57.00	13.00
18	Orenco, near Hillsboro, OR	Distrib./unattended	115.00	13.00	
19	Orient, near Gresham, OR	Distrib./unattended	57.00	13.00	
20	Oswego, Lake Oswego, OR	Distrib./unattended	115.00	13.00	
21	Oxford, Salem, OR	Distrib./unattended	115.00	13.00	
22	Peninsula Park, Portland, OR	Distrib./unattended	115.00	13.00	
23	Pleasant Valley, near Portland, OR	Distrib./unattended	115.00	12.50	
24	Portsmouth, Portland, OR	Distrib./unattended	115.00	13.00	
25	Progress, near Tigard, OR	Distrib./unattended	115.00	13.00	
26	Raleigh Hills, near Portland, OR	Distrib./unattended	115.00	13.00	
27	Ramapo, near Portland, OR	Distrib./unattended	115.00	13.00	
28	Redland, near Oregon City, OR	Distrib./unattended	115.00	13.00	
29	Reedville, near Beaverton, OR	Distrib./unattended	115.00	13.00	
30	Rhododendron Switching, OR	Distrib./unattended	57.00		
31	Rivergate South Yard, near Portland, OR	Distrib./unattended	115.00	13.00	
32	Rivergate South Yard, near Portland, OR	Distrib./unattended	115.00	11.00	
33	Riverview, Portland, OR	Distrib./unattended	115.00	13.00	
34	Rockwood, near Gresham, OR	Distrib./unattended	115.00	13.00	
35	Rosemont, near Lake Oswego, OR	Distrib./unattended	115.00	13.00	
36	Roseway, Hillsboro, OR	Distrib./unattended	115.00	13.00	
37	Ruby, North, Gresham, OR	Distrib./unattended	57.00		
38	Ruby, South, Gresham, OR	Distrib./unattended	57.00	13.00	
39	Salem-PGE, near Salem, OR	Distrib./unattended	57.00	13.00	
40	Sandy, Sandy, 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 2014/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	Scappoose, Scappoose, OR	Distrib./unattended	115.00		
2	Scholls Ferry, Beaverton, OR	Distrib./unattended	115.00	13.00	
3	Scoggin, near Gaston, OR	Distrib./unattended	57.00	13.00	
4	Sellwood, Portland, OR	Distrib./unattended	115.00	57.00	13.00
5	Sellwood, Portland, OR	Distrib./unattended	115.00	13.00	
6	Sheridan, Sheridan, OR	Distrib./unattended	57.00	13.00	
7	Silverton, Silverton, OR	Distrib./unattended	57.00	13.00	
8	Six Corners, Six Corners, OR	Distrib./unattended	115.00	13.00	
9	Springbrook, Newberg, OR	Distrib./unattended	115.00	13.00	
10	Springdale, near Springdale, OR	Distrib./unattended		12.50	
11	St. Helens, near St. Helens, OR	Distrib./unattended	115.00		
12	St. Johns-BPA, near Portland, OR	Distrib./unattended		11.00	
13	St. Louis, St. Louis, OR	Distrib./unattended	57.00	13.00	
14	St. Marys, East Yard, near Beaverton, OR	Distrib./unattended	115.00	13.00	
15	Stephens, Portland, OR	Distrib./unattended	57.00	11.00	
16	Sullivan, West Linn, OR	Distrib./unattended	115.00	13.00	
17	Summit, Government Camp, OR	Distrib./unattended	57.00	13.00	
18	Summit, Government Camp, OR	Distrib./unattended	24.00	13.00	
19	Sunset, near Hillsboro, OR	Distrib./unattended	115.00	13.00	
20	Sunset, near Hillsboro, OR	Distrib./unattended	115.00	34.50	
21	Swan Island, Portland, OR	Distrib./unattended	115.00	13.00	
22	Sylvan, near Portland, OR	Distrib./unattended	115.00	13.00	
23	Tabor, Portland, OR	Distrib./unattended	115.00	13.00	
24	Tabor, Portland, OR	Distrib./unattended	57.00		
25	Tektronix, Beaverton, OR	Distrib./unattended	115.00	13.00	
26	Tigard, Tigard, OR	Distrib./unattended	115.00	12.50	
27	Town Center, Portland, OR	Distrib./unattended	115.00	13.00	
28	Tualitin, Tualitin, OR	Distrib./unattended	115.00	13.00	
29	Twilight, Canby, OR	Distrib./unattended	57.00	13.00	
30	University, Salem, OR	Distrib./unattended	115.00	13.00	
31	Urban, Portland, OR	Distrib./unattended	115.00	13.00	
32	Waconda, near Hopmere, OR	Distrib./unattended	57.00	12.50	
33	Wallace, Salem, OR	Distrib./unattended	115.00	13.00	
34	Welches, near Welches, OR	Distrib./unattended	57.00	24.00	
35	Welches, near Welches, OR	Distrib./unattended	57.00	13.00	
36	West Portland, Lower Yard, near Tigard, OR	Distrib./unattended	115.00		
37	West Portland, Upper Yard, near Tigard, OR	Distrib./unattended	115.00	13.00	
38	West Union, near Hillsboro, OR	Distrib./unattended	57.00	12.50	
39	Willamina, near Willamina, OR	Distrib./unattended	57.00	13.00	
40	Willbridge, Portland, OR	Distrib./unattended	115.00	11.00	

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 2014/Q4

SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Wilsonville, near Wilsonville, OR	Distrib./unattended	57.00	13.00	
2	Woodburn, Woodburn, OR	Distrib./unattended	57.00	13.00	
3	Yamhill, near Yamhill, OR	Distrib./unattended	57.00	13.00	
4					
5					
6					
7	Bakeoven, BPA, near Bakeoven, OR	Transm./unattended	500.00		
8	Beaver Plant, near Clatskanie, OR	Transm./unattended	230.00	13.00	
9	Beaver Plant, near Clatskanie, OR	Transm./unattended	230.00	24.00	
10	Bethel, Salem, OR	Transm./unattended	230.00	115.00	13.00
11	Bethel, Salem, OR	Transm./unattended	115.00	57.00	13.00
12	Bethel, Salem, OR	Transm./unattended	115.00	13.00	
13	Biglow Canyon Wind Farm, Wasco, OR	Transm./unattended	230.00	34.50	13.80
14	Blue Lake, Troutdale, OR	Transm./unattended	230.00	115.00	13.00
15	Blue Lake, Troutdale, OR	Transm./unattended	115.00	13.00	
16	Boardman, near Boardman, OR	Transm./unattended	500.00	24.00	
17	Boardman, OR	Transm./unattended	230.00	7.20	
18	Boardman, OR	Transm./unattended	24.00	7.20	
19	Broadview Subst. near Broadview, MT	Transm./unattended	500.00	230.00	
20	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	Gresham, near Gresham, OR	Transm./unattended	230.00	115.00	13.00
31	Grizzly, BPA, near Madras, OR	Transm./unattended	500.00		
32	Horizon, Hillsboro, OR	Transm./unattended	230.00	115.00	13.00
33	Keeler, BPA, Hillsboro, OR				
34	Linneman, near Gresham, OR	Transm./unattended	230.00	115.00	13.00
35	Malin, BPA, near Malin, OR	Transm./unattended	500.00		
36	McLoughlin, near Oregon City, OR	Transm./unattended	230.00	115.00	13.00
37	Monitor, near Monitor, OR	Transm./unattended	230.00	57.00	13.00
38	Murrayhill, Beaverton, OR	Transm./unattended	230.00	115.00	13.00
39	Murrayhill, Beaverton, OR	Transm./unattended	115.00	13.00	
40	North Fork, near Estacada, OR	Transm./unattended	115.00	13.00	

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Oak Grove, Three Lynx, OR	Transm./unattended	115.00	13.00	
2	Oak Grove, Three Lynx, OR	Transm./unattended	115.00	11.00	
3	Oak Grove, Three Lynx, OR	Transm./unattended	13.00	11.00	
4	Oak Grove, Three Lynx, OR	Transm./unattended	13.00	0.48	
5	Pearl, BPA, near Wilsonville, OR	Transm./unattended	230.00		
6	Pelton, near Madras, OR	Transm./unattended	230.00	13.00	
7	Pelton, near Madras, OR	Transm./unattended	13.00	13.00	
8	Port Westward, near Clatskanie, OR	Transm./unattended	230.00	18.00	16.50
9	River Mill, near Estacada, OR	Transm./unattended	57.00	11.00	
10	Rivergate North Yard, near Portland, OR	Transm./unattended	230.00	115.00	13.00
11	Round Butte, near Madras, OR	Transm./unattended	500.00	230.00	12.50
12	Round Butte, near Madras, OR	Transm./unattended	230.00	12.50	
13	Sand Springs, 22 mi E/22 mi S of Bend, OR	Transm./unattended	500.00		
14	Sherwood, near Six Corners, OR	Transm./unattended	230.00	115.00	13.00
15	Slatt, BPA, Arlington, OR	Transm./unattended	500.00		
16	St. Marys, West Yard, near Beaverton, OR	Transm./unattended	230.00	115.00	13.00
17	Sullivan, West Linn, OR	Transm./Unattended	57.00	4.15	
18	Sycan, 27 mi S of Silver Lake, OR	Transm./unattended	500.00		
19	Trojan, near Rainier, OR	Transm./unattended	230.00	12.50	
20	Tucannon Mullan Switchyard, Dayton, WA	Transm./unattended	230.00	34.50	13.00
21	TOTAL MVa		28853.00	4977.03	379.80
22					
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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 Type of Equipment	Number of Units	Total Capacity (In MVa)	Line No.
(f)	(g)	(h)	(i)	(j)	(k)	
69	9		Capacitor Banks	3	15,600	1
17	1					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

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 2014/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.
17	1					1
32	2		Capacitor Banks	4	14,400	2
26	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
17	1		Capacitor Banks	2	7,200	14
50	2		Capacitor Banks	4	12,000	15
28	1		Capacitor Banks	2	6,600	16
34	2					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	13,200	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 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 2014/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.
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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
19	1					4
29	1					5
34	1					6
42	2		Capacitor Banks	4	9,000	7
20	1		Capacitor Banks	3	15,000	8
45	2		Capacitor Banks			9
39	2		Capacitor Banks	3	9,600	10
45	2		Capacitor Banks	4	12,000	11
31	3		Capacitor Banks	3	15,000	12
20	1		Capacitor Banks	4	18,000	13
28	2					14
56	2		Capacitor Banks	4	14,400	15
						16
280	2					17
81	3		Capacitor Banks	6	18,600	18
15	2					19
34	2		Capacitor Banks	2	7,200	20
50	2		Capacitor Banks	4	12,300	21
28	1		Capacitor Banks	2	6,000	22
55	2		Capacitor Banks	4	12,000	23
28	1					24
50	2		Capacitor Banks	4	13,800	25
28	1		Capacitor Banks	2	6,600	26
28	1		Capacitor Banks	2	6,000	27
22	1					28
84	3		Capacitor Banks	6	18,000	29
						30
22	1		Capacitor Banks	2	7,200	31
22	1		Capacitor Banks	2	6,716	32
28	1		Capacitor Banks	2	6,000	33
78	3		Capacitor Banks	5	10,200	34
28	1		Capacitor Banks		6,000	35
28	1		Capacitor Banks	2	6,000	36
						37
15	2		Capacitor Banks	2	3,600	38
45	2		Capacitor Banks	4	12,000	39
28	1		Capacitor Banks	2	6,000	40

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 2014/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.
						1
28	1		Capacitor Banks	2	6,000	2
13	2		Capacitor Banks	1	10,800	3
140	1		Capacitor Banks	1	24,000	4
28	1		Capacitor Banks	2	6,000	5
17	1		Capacitor Banks	3	19,200	6
33	3		Capacitor Banks	2	3,600	7
49	2		Capacitor Banks	2	6,000	8
56	2		Capacitor Banks	5	36,000	9
						10
			Capacitor Banks	1	24,000	11
						12
24	2		Capacitor Banks	2	7,200	13
56	2		Capacitor Banks	4	12,000	14
100	2		Capacitor Banks	2	16,800	15
45	2		Capacitor Banks	5	36,000	16
8	1	1				17
14	1					18
378	8		Capacitor Banks	21	105,618	19
100	2					20
53	2		Capacitor Banks	4	12,000	21
22	1		Capacitor Banks	2	6,000	22
22	1		Capacitor Banks	2	6,000	23
						24
56	2		Capacitor Banks	4	12,000	25
45	2		Capacitor Banks	4	12,000	26
56	2		Capacitor Banks	2	6,000	27
56	2		Capacitor Banks	4	13,200	28
28	1		Capacitor Banks	3	19,200	29
22	1		Capacitor Banks	2	7,200	30
112	4		Capacitor Banks	7	43,200	31
41	2		Capacitor Banks	2	6,000	32
28	1		Capacitor Banks	2	6,000	33
10	1		Capacitor Banks	1	12,000	34
18	2		Capacitor Banks	2	6,000	35
			Capacitor Banks	1	24,000	36
56	2		Capacitor Banks	4	13,200	37
28	1		Capacitor Banks	3	15,200	38
24	2		Capacitor Banks	3	7,800	39
20	1					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (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.
84	3		Capacitor Banks	6	18,000	1
42	2		Capacitor Banks	4	13,200	2
15	2		Capacitor Banks	1	1,800	3
						4
						5
						6
						7
464	4					8
170	1					9
502	2					10
140	1					11
28	1		Capacitor Banks	2	6,000	12
480	3					13
320	1					14
28	1		Capacitor Banks	2	6,000	15
685	3					16
55	1					17
55	1					18
80	3					19
						20
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
572	2					30
						31
320	1					32
						33
168	1					34
			Reactors	3	180,000	35
640	2					36
125	1					37
320	1					38
56	2		Capacitor Banks	2	10,800	39
53	3	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.
8	1					1
64	2					2
						3
						4
						5
164	4					6
3	1					7
450	3					8
32	2					9
520	4		Capacitor Banks	1	22,000	10
561	3		Reactors	12	180,000	11
394	4	2				12
			Series Capacitor	1	546,000	13
640	2					14
						15
960	3		Capacitor Banks	3	108,000	16
33	1					17
			Series Capacitor	1	546,000	18
56	2					19
320	2		Capacitors/Reactors	6	90,000	20
18107	360	4		412	3,529,904	21
						22
						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 regulation 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 regulation 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 regulation equipment.

Schedule Page: 426.2 Line No.: 16 Column: a

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

Schedule Page: 426.2 Line No.: 30 Column: a

Switching only.

Schedule Page: 426.2 Line No.: 37 Column: a

Switching only.

Schedule Page: 426.3 Line No.: 1 Column: a

Switching only. Distribution owned by Columbia River PUD.

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

Regulating only.

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

Switching only. Distribution owned by Columbia River PUD.

Schedule Page: 426.3 Line No.: 12 Column: a

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

Schedule Page: 426.3 Line No.: 24 Column: a

Switching only.

Schedule Page: 426.3 Line No.: 36 Column: a

Switching only.

Schedule Page: 426.4 Line No.: 7 Column: a

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

Schedule Page: 426.4 Line No.: 16 Column: a

Jointly owned with Idaho Power Company. PGE has an 90% share of the jointly owned capacity. 100% of the capacity is reported.

Schedule Page: 426.4 Line No.: 17 Column: a

Jointly owned with Idaho Power Company. PGE has an 90% share of the jointly owned capacity, 100% of the capacity is reported.

Schedule Page: 426.4 Line No.: 18 Column: a

Jointly owned with Idaho Power Company. PGE has an 90% share of the jointly owned capacity. 100% of the capacity is reported.

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

Jointly owned with Northwestern Energy LLC, Puget Sound Energy, Inc., PacifiCorp, and Avista Corporation. PGE has a 16% share of the jointly owned capacity. 100% of the capacity is reported.

Schedule Page: 426.4 Line No.: 20 Column: a

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

Schedule Page: 426.4 Line No.: 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 2006 in the amount of 261,281 to FERC account 353.
Contribution in aid of construction made to Bonneville Power Administration in 1995 in the amount of 1,115,709 to FERC account 353.

Schedule Page: 426.4 Line No.: 29 Column: a

Line compensation only.

Schedule Page: 426.4 Line No.: 31 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.: 33 Column: a

Owned and operated by Bonneville Power Administration. Contribution in aid of construction made to BPA in 2012 in the amount of 2,881,411 recorded to FERC account 353.

Schedule Page: 426.4 Line No.: 35 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.: 5 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.: 6 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.: 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.: 12 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

Line compensation only.

Schedule Page: 426.5 Line No.: 15 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.: 18 Column: a

Line compensation only.

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 2014/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	930,800
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21				
22	Administrative Services	Salmon Springs Hospitality Group	186	945,050
23				
24				
25				
26				
27				
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