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

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2014)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2014)
Form 3-Q Approved
OMB No.1902-0205
(Expires 05/31/2014)

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** 2013/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 2013/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*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(503) 464-7121	(1) [X] An Original (2) [ ] A Resubmission	/ /

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name / 02 Title	03 Signature	04 Date Signed *(Mo, Da, Yr)*
01 Name James F. Lobdell 02 Title SVP of Finance, CFO and Treasurer	James F. Lobdell	03/18/2014

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 2013/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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	Not Applicable
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	Not Applicable
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	None
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	None
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	
24	Extraordinary Property Losses	230	None
25	Unrecovered Plant and Regulatory Study Costs	230	
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	Not Applicable

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	None
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Regional Transmission Service Revenues (Account 457.1)	302	None
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310-311	
46	Electric Operation and Maintenance Expenses	320-323	
47	Purchased Power	326-327	
48	Transmission of Electricity for Others	328-330	
49	Transmission of Electricity by ISO/RTOs	331	Not Applicable
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant	336-337	
53	Regulatory Commission Expenses	350-351	
54	Research, Development and Demonstration Activities	352-353	
55	Distribution of Salaries and Wages	354-355	
56	Common Utility Plant and Expenses	356	None
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	Not Applicable
61	Electric Energy Account	401	
62	Monthly Peaks and Output	401	
63	Steam Electric Generating Plant Statistics	402-403	
64	Hydroelectric Generating Plant Statistics	406-407	
65	Pumped Storage Generating Plant Statistics	408-409	None
66	Generating Plant Statistics Pages	410-411	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

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

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	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 2013/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.

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	0.01	
15				
16	SunWay 2, LLC	Solar power generation	0.01	
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18	SunWay 3, LLC	Solar power generation	0.01	
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27				

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

SunWay 1, 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.: 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 2013/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	708,559
2	Senior Vice President of Finance, Chief Financial	James F. Lobdell	301,664
3	Officer and Treasurer		
4	Senior Vice President of Power Supply & Operations	Maria M. Pope	421,135
5	and Resource Strategy		
6	Senior Vice President, Customer Service,	William O. Nicholson	282,534
7	Transmission and Distribution		
8	Vice President, General Counsel and Corporate	J. Jeffery Dudley	324,411
9	Compliance Officer		
10	Vice President, Nuclear and Power Supply/Generation	Stephen M. Quennoz	292,562
11	Vice President, Vice President, Human Resources,	Arleen N. Barnett	257,459
12	Diversity and Inclusion, and Administration		
13	Vice President, Customer Strategies and Business	Carol A. Dillin	259,081
14	Development		
15	Vice President, Information Technology and Chief	Campbell A. Henderson	222,368
16	Information Officer		
17	Vice President, Distribution	O. Bruce Carpenter	243,966
18	Vice President, Public Policy	W. David Robertson	242,571
19	Vice President, Customer Service Operations	Kristin A. Stathis	197,302
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Schedule Page: 104 Line No.: 1 Column: c

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

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 (formerly The Regence Group)	
16	Corbin A. McNeill, Jr.	Jackson Hole, Wyoming
17	Retired Chair of the Board of Portland General Electric	
18	Retired Chairman and co-Chief Executive Officer of	
19	Exelon Corp.	
20	Neil J. Nelson	Portland, Oregon
21	President and Chief Executive Officer of Siltronic Corp.	
22	M. Lee Pelton	Boston, Massachusetts
23	President of Emerson College	
24	James J. Piro	Portland, Oregon
25	President and Chief Executive Officer of	
26	Portland General Electric Company	
27	Robert T. F. Reid	Vancouver, British Columbia, Canada
28	Retired Chair and Corporate Director of British Columbia	
29	Transmission Corporation	
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Schedule Page: 105 Line No.: 5 Column: a

Elected to succeed Mr. McNeill as Chairman of the Board, effective October 31, 2013.

Schedule Page: 105 Line No.: 16 Column: a

Mr. McNeill retired from the Board effective October 31, 2013.

Schedule Page: 105 Line No.: 27 Column: a

Mr. Reid passed away on June 28, 2013.

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 2013/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 2013/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 2013/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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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

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

1. None

2. None

3. 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 Generally Accepted Accounting Principles and the FERC's Uniform System of Accounts. Proposed final accounting entries will be submitted to the FERC no later than June 30th, 2014, which is within six months after the transaction was consummated, as required.

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.

PGE has the following two unsecured revolving credit facilities as of December 31, 2013, that together provide a total of $700 million in available short-term financing: 1) a $300 million syndicated credit facility, which is scheduled to terminate in December 2017; and 2) a $400 million syndicated credit facility, which is scheduled to terminate in November 2018. As of December 31, 2013, PGE had no borrowings or commercial paper outstanding and $37 million of letters of credit issued under the revolving credit facilities.

The Company also has two letter of credit facilities under which it may obtain letters of credit in an aggregate amount not to exceed $60 million. As of December 31, 2013, PGE had issued an additional $37 million of letters of credit under these facilities.

During 2013, PGE issued a total of $380 million of First Mortgage Bonds (FMBs) as authorized by the Public Utilities Commission of Oregon (OPUC) in its March 26, 2013 Order No. 13-098 in Docket No. UF 4259, consisting of the following:

- In June, issued $150 million of 4.47% Series FMBs due 2044;
- In August, issued $75 million of 4.47% Series FMBs due 2043;
- In November, issued $105 million of 4.74% Series FMBs due 2042;
- In December, issued $50 million of 4.84% Series FMBs due 2048.

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, 2013, management believes the likelihood is remote that PGE would be required to perform under such indemnification provisions or otherwise incur any significant losses with respect to such indemnities. The Company has not recorded any liability on the consolidated balance sheets with respect to these indemnities.

7. None

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 Public Utility Commission of Oregon (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. Opening briefs have been filed and oral argument occurred March 4, 2014.

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 July 2001, the FERC called for a preliminary evidentiary 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. During that period, PGE both sold and purchased electricity in the Pacific Northwest. In June 2003, the FERC issued an order terminating the proceeding and denying the claims for refunds. Parties appealed various aspects of these FERC orders to the U.S. Ninth Circuit Court of Appeals (Ninth Circuit).

In August 2007, the Ninth Circuit issued its decision on appeal, concluding that the FERC failed to adequately explain how it considered or examined new evidence showing intentional market manipulation in California and the potential ties to the Pacific Northwest and that the FERC should not have excluded from the Pacific Northwest Refund proceeding purchases of energy made by the California Energy Resources Scheduling (CERS) division in the Pacific Northwest spot market. The Ninth Circuit remanded the case to the FERC to (i) address the new market manipulation evidence in detail and account for the evidence in any future orders regarding the award or denial of refunds in the proceedings, (ii) include sales to CERS in its analysis, and (iii) further consider its refund decision in light of related, intervening opinions of the court. The Ninth Circuit offered no opinion on the FERC's findings based on the record established by the administrative law judge and did not rule on the FERC's ultimate decision to deny refunds. After denying requests for rehearing, the Ninth Circuit, in April 2009, issued a mandate giving immediate effect to its August 2007 order remanding the case to the FERC.

In October 2011, the FERC issued an Order on Remand establishing an evidentiary hearing to determine whether any seller had engaged in unlawful market activity in the Pacific Northwest spot markets during the December 25, 2000 through June 20, 2001 period by violating specific contracts or tariffs, and, if so, whether a direct connection existed between the alleged unlawful conduct and the rate charged under the applicable contract. The FERC 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 before a refund could be ordered. 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. Certain parties claiming refunds filed requests for rehearing of the Order on Remand.

In December 2012, the FERC issued an order granting an interlocutory appeal of the trial judge's ruling on the scope of the remand proceeding. In this order, the FERC held that its Order on Remand was not intended to alter the general state of the law regarding the Mobile-Sierra presumption. The FERC also held that the Mobile-Sierra presumption could be 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.

On April 5, 2013, and subject to its December 2012 clarification in the interlocutory appeal, the FERC denied rehearing requests from refund proponents that had contested the FERC's use of the Mobile-Sierra standard in the remand proceeding, its denial of a market-wide remedy, and the restraints in the Order on Remand that limited the types of evidence that could be introduced in the hearing. However, the FERC granted rehearing on the issue of the appropriate refund period, holding that parties could 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. Refund claimants have filed petitions for appeal of the Order on Remand and the Order on Rehearing with the Ninth Circuit.

In its October 2011 Order on Remand, the FERC held the hearing procedures in abeyance pending the results of settlement discussions, which it ordered be convened before a FERC settlement judge. Pursuant to the settlement proceedings, 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.

In May 2007, the FERC approved a settlement between PGE and certain parties in the California refund case in Docket No. EL00-95, et seq. This resolved the 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. The settlement with the California parties did not resolve 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 ongoing remand proceedings, which are limited to initial and direct claims for refunds, but there remains a possibility that additional claims could be asserted against the Company in future proceedings if refunds are ordered against current respondents.

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 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, 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 suit. On September 27, 2013, the plaintiffs filed an amended complaint that deleted the 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. This matter is scheduled for trial in March 2015.

10. None

11. (Reserved)

12. None

13. Changes in Directors and Officers:

On February 20, 2013, the board of directors of Portland General Electric Company appointed Maria M. Pope as the Company's Senior Vice President of Power Supply and Operations, and Resource Strategy, and James F. Lobdell as the Company's Senior Vice President of Finance, Chief Financial Officer and Treasurer. Both appointments were effective March 1, 2013.

Robert T. F. Reid, director, passed away on June 28, 2013.

On October 30, 2013, Corbin A. McNeill, Jr., Chairman of the Board of Directors of the Company (the Board) notified the Board of his retirement from the Board effective October 31, 2013. Mr. McNeill was a member of the Nominating and Corporate Governance Committee of the Board. The Board elected director Jack E. Davis to succeed Mr. McNeill as Chairman of the Board, effective October 31, 2013. Mr. Davis has been a member of the Board since June 2012 and also serves on the Nominating and Corporate Governance Committee.

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 2013/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	7,090,483,780	6,806,135,364
3	Construction Work in Progress (107)	200-201	507,603,106	140,303,251
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		7,598,086,886	6,946,438,615
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	3,469,615,339	3,250,583,440
6	Net Utility Plant (Enter Total of line 4 less 5)		4,128,471,547	3,695,855,175
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)		4,128,471,547	3,695,855,175
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		29,584,446	28,250,053
19	(Less) Accum. Prov. for Depr. and Amort. (122)		12,642,675	12,977,481
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	4,060,819	3,722,671
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)		117,942,828	70,949,452
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		1,542,540	2,562,521
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		140,487,958	92,507,216
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		2,126,637	11,578,489
36	Special Deposits (132-134)		8,977,158	45,558,970
37	Working Fund (135)		23,067	25,367
38	Temporary Cash Investments (136)		104,000,000	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		136,264,476	117,278,145
41	Other Accounts Receivable (143)		15,388,642	40,152,976
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		5,865,261	5,300,261
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		590,693	287,260
45	Fuel Stock (151)	227	24,019,002	39,663,607
46	Fuel Stock Expenses Undistributed (152)	227	1,402,813	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	34,783,468	33,167,801
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	478,608	252,288

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 2013/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	4,765,622	4,817,251
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)		41,592,784	53,874,917
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)		103,522,377	96,665,402
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		14,322,488	6,078,475
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		1,542,540	2,562,521
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)		484,850,034	441,538,166
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		10,862,206	9,181,075
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	3,402,786
72	Other Regulatory Assets (182.3)	232	516,243,189	645,926,821
73	Prelim. Survey and Investigation Charges (Electric) (183)		1,441,335	13,145,091
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)		140,232	178,997
77	Temporary Facilities (185)		0	57,891
78	Miscellaneous Deferred Debits (186)	233	16,551,169	14,170,614
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)		16,779,494	21,958,086
82	Accumulated Deferred Income Taxes (190)	234	305,006,638	339,534,982
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		867,024,263	1,047,556,343
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		5,620,833,802	5,277,456,900

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 2013/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	905,787,872	832,388,455
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	16,366,513	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	7,776,148
11	Retained Earnings (215, 215.1, 216)	118-119	912,391,179	893,192,136
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	102,547	-135,601
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)	-5,062,788	-6,376,798
16	Total Proprietary Capital (lines 2 through 15)		1,818,752,680	1,727,658,557
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,916,400,000	1,636,400,000
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	95,828	101,817
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		770,596	880,399
24	Total Long-Term Debt (lines 18 through 23)		1,915,725,232	1,635,621,418
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)		8,484,264	7,939,406
29	Accumulated Provision for Pensions and Benefits (228.3)		261,246,787	354,789,256
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		9,905,441	7,905,584
32	Long-Term Portion of Derivative Instrument Liabilities		141,371,181	72,963,408
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		99,533,202	93,721,755
35	Total Other Noncurrent Liabilities (lines 26 through 34)		520,540,875	537,319,409
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	16,999,434
38	Accounts Payable (232)		254,713,428	180,099,242
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		490,937	425,485
41	Customer Deposits (235)		14,655,022	13,781,610
42	Taxes Accrued (236)	262-263	9,239,822	17,799,529
43	Interest Accrued (237)		23,164,992	22,696,098
44	Dividends Declared (238)		22,378,496	21,322,540
45	Matured Long-Term Debt (239)		0	0

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		11,467,270	11,354,877
48	Miscellaneous Current and Accrued Liabilities (242)		8,451,916	13,961,668
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		190,600,317	199,714,587
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		141,371,181	72,963,408
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)		393,791,019	425,191,662
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	11,009,032	1,596,555
60	Other Regulatory Liabilities (254)	278	111,443,593	73,382,141
61	Unamortized Gain on Reaquired Debt (257)		74,481	82,533
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		619,065,292	597,926,639
64	Accum. Deferred Income Taxes-Other (283)		230,431,598	278,677,986
65	Total Deferred Credits (lines 56 through 64)		972,023,996	951,665,854
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		5,620,833,802	5,277,456,900

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 2013/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	1,845,416,891	1,823,171,165		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,119,861,086	1,050,371,588		
5	Maintenance Expenses (402)	320-323	112,564,149	116,283,095		
6	Depreciation Expense (403)	336-337	228,686,066	222,779,529		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	3,771,528	2,906,607		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	22,054,865	21,547,511		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		3,500,000	3,500,396		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		5,620,441	15,321,396		
13	(Less) Regulatory Credits (407.4)		17,923,138	21,047,348		
14	Taxes Other Than Income Taxes (408.1)	262-263	102,358,656	101,046,406		
15	Income Taxes - Federal (409.1)	262-263	27,599,530	16,674,750		
16	- Other (409.1)	262-263	4,306,119	482,682		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	234,017,928	301,377,302		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	225,398,603	254,055,178		
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)			12,796		
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		2,291,604	1,792,958		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,623,310,231	1,578,994,490		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		222,106,660	244,176,675		

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 2013/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

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

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
1,845,416,891	1,823,171,165					2
						3
1,119,861,086	1,050,371,588					4
112,564,149	116,283,095					5
228,686,066	222,779,529					6
3,771,528	2,906,607					7
22,054,865	21,547,511					8
						9
3,500,000	3,500,396					10
						11
5,620,441	15,321,396					12
17,923,138	21,047,348					13
102,358,656	101,046,406					14
27,599,530	16,674,750					15
4,306,119	482,682					16
234,017,928	301,377,302					17
225,398,603	254,055,178					18
						19
						20
	12,796					21
						22
						23
2,291,604	1,792,958					24
1,623,310,231	1,578,994,490					25
222,106,660	244,176,675					26

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)		222,106,660	244,176,675		
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	225,478		
33	Revenues From Nonutility Operations (417)		3,305,302	3,636,103		
34	(Less) Expenses of Nonutility Operations (417.1)		2,399,247	3,151,534		
35	Nonoperating Rental Income (418)		2,059,541	1,278,410		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	588,148	479,392		
37	Interest and Dividend Income (419)		125,871	105,780		
38	Allowance for Other Funds Used During Construction (419.1)		12,755,088	6,067,376		
39	Miscellaneous Nonoperating Income (421)		6,701,374	1,064,528		
40	Gain on Disposition of Property (421.1)		66,775	-90,406		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		23,168,034	9,164,171		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)			4,864		
45	Donations (426.1)		1,648,042	1,807,987		
46	Life Insurance (426.2)		-2,810,998	-1,942,614		
47	Penalties (426.3)		91,587	14,456		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		800,736	725,643		
49	Other Deductions (426.5)		58,500,515	3,016,725		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		58,229,882	3,627,061		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	1,236,915	1,146,300		
53	Income Taxes-Federal (409.2)	262-263	-18,019,089	-1,114,917		
54	Income Taxes-Other (409.2)	262-263	-4,277,692	-13,115		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	3,635,375	2,451,443		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	940,796	2,062,663		
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)		-18,365,287	407,048		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-16,696,561	5,130,062		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		96,939,583	99,124,496		
63	Amort. of Debt Disc. and Expense (428)		1,076,551	2,294,416		
64	Amortization of Loss on Reaquired Debt (428.1)		5,178,592	6,068,563		
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)		4,523,785	4,210,794		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		6,891,655	3,699,361		
70	Net Interest Charges (Total of lines 62 thru 69)		100,818,804	107,990,856		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		104,591,295	141,315,881		
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)		104,591,295	141,315,881		

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		889,339,341	829,756,801
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)		104,003,147	140,836,489
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			-85,154,104	(81,653,949)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-85,154,104	(81,653,949)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		350,000	400,000
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		908,538,384	889,339,341
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		3,852,795	3,852,795
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		3,852,795	3,852,795
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		912,391,179	893,192,136
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-135,601	(214,993)
50	Equity in Earnings for Year (Credit) (Account 418.1)		588,148	479,392
51	(Less) Dividends Received (Debit)		350,000	400,000
52				
53	Balance-End of Year (Total lines 49 thru 52)		102,547	(135,601)

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 2013/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)	104,591,295	141,315,881
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	254,512,459	247,233,647
5	Amortization of Debt Discount	6,247,091	8,354,927
6	Amortization of Unrecovered Plant	3,500,000	3,500,396
7	Price Risk Management	-17,358,283	-174,190,283
8	Deferred Income Taxes (Net)	11,313,904	47,710,904
9	Investment Tax Credit Adjustment (Net)		
10	Net (Increase) Decrease in Receivables	-817,405	-4,179,336
11	Net (Increase) Decrease in Inventory	12,451,434	-6,418,092
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	4,613,174	4,931,546
14	Net (Increase) Decrease in Other Regulatory Assets	27,222,148	176,573,309
15	Net Increase (Decrease) in Other Regulatory Liabilities	-6,402,569	-2,885,465
16	(Less) Allowance for Other Funds Used During Construction	12,755,088	6,067,376
17	(Less) Undistributed Earnings from Subsidiary Companies	588,148	479,392
18	Other: Proceeds Received from Trojan Spent Fuel Legal Settlement	44,254,757	
19	Other: Write Off Casade Crossing Transmission Project	51,919,581	
20	Other: Margin and Customer Deposits	37,455,224	39,918,718
21	Other Operating	22,853,133	20,918,766
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	543,012,707	496,238,150
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-653,185,696	-302,421,677
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-2,422,590	-588,320
30	(Less) Allowance for Other Funds Used During Construction	-12,755,088	-6,067,376
31	Other (provide details in footnote):		
32	Other Capital Expenditures	-4,471,466	-6,834,667
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-647,324,664	-303,777,288
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38	Sale of Utility Property	481,156	9,750,000
39	Investments in and Advances to Assoc. and Subsidiary Companies	-688,148	-271,608
40	Contributions and Advances from Assoc. and Subsidiary Companies	350,000	400,000
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 2013/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48	Other Investments	575,099	2,647,014
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	-26,357,249	-25,501,801
54	Sale of Trojan Decommissioning Trust Securities	25,129,569	22,807,578
55	Contribution to Nuclear Decommissioning Trust	-44,151,519	
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-691,985,756	-293,946,105
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	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)	481,711,004	
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-100,005,989	-100,005,989
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Debt Issuance Costs	-2,634,980	-1,318,750
78	Net Decrease in Short-Term Debt (c)	-16,999,434	-12,998,541
79	Payments on Revolving Line of Credit	-35,000,000	
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-83,551,704	-81,358,854
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	243,518,897	-195,682,134
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	94,545,848	6,609,911
87			
88	Cash and Cash Equivalents at Beginning of Period	11,603,856	4,993,945
89			
90	Cash and Cash Equivalents at End of period	106,149,704	11,603,856

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

During the third quarter of 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. 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: b

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 "Electric Utility Plant, Net" within Note 2: Balance Sheet Components, contained on p. 123 herein.

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

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.: 38 Column: c

In January 2012, PGE completed construction of a $10 million, 1.75 MW solar powered electrical generating facility, which was sold to, and simultaneously leased-back from, a financial institution. The Company operates the facility and receives 100% of the power generated by this facility.

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

During the third quarter of 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. 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.

NOTES TO FINANCIAL STATEMENTS

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

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

Supplemental Disclosures

Supplemental Information to Statement of Cash Flows

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

	Balance at Beginning of Year	Balance at End of Year
Cash (131)	$ 11,578,489	$ 2,126,637
Working Funds (135)	25,367	23,067
Temporary Cash Investments (136)	—	104,000,000
	$ 11,603,856	$ 106,149,704

	2012	2013
Cash paid during the year:		
Interest	$ 100,320,282	$ 96,535,309
AFDC - Borrowed	(3,699,361)	(6,891,655)
	$ 96,620,921	$ 89,643,654
Income Taxes	$ 13,401,781	$ 10,360,000
Non-cash investing and financing activities:		
Accrued capital additions	$ 18,547,538	$ 84,469,331
Accrued dividends payable	21,332,540	22,378,496
Preliminary engineering transferred to Construction work in progress from Other noncurrent assets	—	9,379,785

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, 2013, PGE served 836,070 retail customers with a service area population of approximately 1.7 million, comprising approximately 44% of the state’s population.

As of December 31, 2013, PGE had 2,596 employees, with 795 employees covered under two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 760 and 35 employees and expire in February 2015 and August 2014, 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 balance sheets 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 on the Company's price risk management activities, see Note 5 - Price Risk Management). In addition, certain items that are considered to be non-operating in nature are recorded in Other deductions in the FERC statements of income but are recorded within Operating expenses in financial statements prepared in accordance with GAAP.

Reclassifications

To conform with the 2013 presentation, PGE collapsed the contribution to voluntary employees' benefit association trust in the amount of $2,195,378 into Other Operating in the Operating Activities section of the statement of cash flows for 2012.

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.

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 $104 million as of December 31, 2013 and none as of December 31, 2012.

Accounts Receivable

Accounts receivable are recorded at invoiced amounts based on prices that are subject to federal (FERC) and state (OPUC) regulations. Balances do not bear interest; however, late fees are assessed beginning 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 receivable related to retail sales are charged to Operation expenses and are recorded in the same period as the related revenues, with an offsetting credit to the Accumulated provision for uncollectible accounts. Such estimates are based on management's assessment of the probability of collection, aging of accounts receivable, bad debt write-offs, actual customer billings, and other factors.

Provisions for uncollectible accounts receivable 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 2013 and 2012.

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 balance sheets 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 classified as Special deposits in the balance sheets and were $9 million and $46 million as of December 31, 2013 and 2012, respectively. Letters of credit provided as collateral are not recorded on the Company's balance sheets and were $29 million and $45 million as of December 31, 2013 and 2012, 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.

Electric Utility Plant

Capitalization Policy

Electric 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 Electric utility plant on the balance sheets. If the project becomes probable of being abandoned, such costs are expensed in the period such determination is made. If any costs are expensed, 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 FERC account 426.5, Other deductions, 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 statements of income. The average rate used by PGE was 7.5% in 2013 and in 2012. AFDC from borrowed funds was $7 million in 2013 and $4 million in 2012 and is reflected as a reduction to Interest expense. AFDC from equity funds was $13 million in 2013 and $6 million in 2012 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 3.7% in 2013 and 3.8% in 2012. Estimated asset retirement removal costs included in depreciation expense were $55 million in 2013 and 2012.

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 2009, with an order received from the OPUC in September 2010 authorizing new depreciation rates effective January 1, 2011. During 2013, a depreciation study was completed, which has been incorporated into the Company’s general rate case filed with the OPUC on February 13, 2014, with new prices expected to become 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 2050. 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 $170 million and $151 million as of December 31, 2013 and 2012, respectively, with amortization expense of $22 million in 2013 and in 2012. Future estimated amortization expense as of December 31, 2013 is as follows: $23 million in 2014; $22 million in 2015; $19 million in 2016; $16 million in 2017; and $14 million in 2018.

Marketable Securities

All of PGE's investments in marketable securities, included in the Non-qualified benefit plan trust and Nuclear decommissioning trust on the balance sheets, 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 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 and fuel 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 variance to be collected from or refunded to customers, subject to a regulated earnings test. Pursuant to the 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 10% for 2013, and 2012.

Any estimated refund to customers pursuant to the PCAM is recorded as a reduction in Revenues in the Company's statements 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 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 will be made by the OPUC through a public filing and review in 2014.

For 2012, actual NVPC was below baseline NVPC by $17 million, and exceeded the lower deadband threshold of $15 million. However, based on results of the regulated earnings test, no estimated refund to customers was recorded as of December 31, 2012. A final determination regarding the 2012 PCAM results was made by the OPUC through a public filing and review in 2013, which confirmed no refund to customers pursuant to the PCAM for 2012.

Asset Retirement Obligations

Legal obligations related to the future retirement of tangible long-lived assets are classified as AROs on PGE's 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 balance sheets 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 and amortization in the statements of income. Changes in the ARO resulting from the passage of time (accretion) is based on the original discount rate and recognized as an increase in the carrying amount of the liability and as a charge to accretion expense, which is classified as Depreciation and amortization expense in the Company's statements 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 balance sheets. PGE had a regulatory liability related to AROs in the amount of $39 million as of December 31, 2013 and 2012. 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 balance sheets 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 statements 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 $41 million in 2013 and $42 million in 2012.

Retail revenue is billed monthly based on meter readings taken throughout the month. Unbilled revenue 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. Unbilled revenue is 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 $76 million and $80 million as of December 31, 2013 and 2012, 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 balance sheets.

PGE records any interest and penalties related to income tax deficiencies in Other interest expense and Other income deductions respectively, in the statements of income.

Recent Accounting Pronouncement

Accounting Standards Update (ASU) 2011-11, *Balance Sheet (Topic 210) - Disclosures about Offsetting Assets and Liabilities* (ASU 2011-11), requires an entity to disclose information about offsetting and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. In addition, ASU 2013-01, *Balance Sheet (Topic 210) - Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities* (ASU 2013-01), was issued in January 2013 and clarifies that the scope of ASU 2011-11 applies to financial instruments accounted for in accordance with Topic 815, *Derivatives and Hedging*. Both ASUs were effective January 1, 2013 for the Company, and require retrospective application. PGE adopted the amendments contained in ASU 2011-11 and ASU 2013-01 on January 1, 2013, which did not have an impact on the Company's financial position, results of operations, or cash flows. See Note 5, Price Risk Management, for the additional disclosures made pursuant to the adoption of these ASUs.

NOTE 3: BALANCE SHEET COMPONENTS

Accounts Receivable

The following is the activity in the Accumulated provision for uncollectible accounts (in millions):

	Years Ended December 31,	
	2013	**2012**
Balance as of beginning of year	$ 5	$ 6
Increase in provision	6	6
Amounts written off, less recoveries	(5)	(7)
Balance as of end of year	$ 6	$ 5

Trust Accounts

PGE maintains two trust accounts as follows:

Nuclear decommissioning trust—Reflects assets held in trust to cover general decommissioning costs and operation of the Independent Spent Fuel Storage Installation (ISFSI) and represent amounts collected from customers less qualified expenditures plus any realized and unrealized gains and losses on the investments held therein. During 2013, the Company received $44 million 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	
	2013	**2012**	**2013**	**2012**
Cash equivalents	$ 59	$ 15	$ —	$ 2
Marketable securities, at fair value:				
Equity securities	—	—	8	5
Debt securities	23	23	1	2
Insurance contracts, at cash surrender value	—	—	26	23
	$ 82	$ 38	$ 35	$ 32

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 balance sheets, for which it is practicable to estimate fair value as of December 31, 2013 and 2012, 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, 2013 and 2012, 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, 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 regulatory assets or 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, 2012			
	Level 1	Level 2	Level 3	Total
Assets:				
Nuclear decommissioning trust (1):				
Money market funds	$ —	$ 15	$ —	$ 15
Debt securities:				
Domestic government	7	8	—	15
Corporate credit	—	8	—	8
Non-qualified benefit plan trust (2):				
Money market funds	—	2	—	2
Equity securities:				
Domestic	2	2	—	4
International	1	—	—	1
Debt securities - domestic government	2	—	—	2
Assets from price risk management activities (1) (3):				
Electricity	—	1	—	1
Natural gas	—	3	2	5
	$ 12	$ 39	$ 2	$ 53
Liabilities - Liabilities from price risk management activities (1) (3):				
Electricity	$ —	$ 72	$ 10	$ 82
Natural gas	—	110	8	118
	$ —	$ 182	$ 18	$ 200

(1) Activities are subject to regulation, with certain gains and losses deferred pursuant to regulatory accounting and included in regulatory assets or regulatory liabilities as appropriate.
(2) Excludes insurance policies of $23 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 in PGE's balance sheets and invested in securities that are exposed to interest rate, credit and market volatility risks. These assets are classified within Level 1, 2 or 3 based on the following factors:

> *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 balance sheets 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 over-the-counter forwards, commodity 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 swaps, forwards, and futures.

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, 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					
As of December 31, 2012:							
Natural gas financial swaps	$ 2	$ 8	Discounted cash flow	Natural gas forward price (per Dth)	$ 3.67	$ 5.21	$ 4.28
Electricity financial swaps	—	10	Discounted cash flow	Electricity forward price (per MWh)	7.12	51.72	41.14
	$ 2	$ 18					

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 quotes from brokers with whom the Company transacts. 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,	
	2013	2012
Net liabilities from price risk management activities as of beginning of year	$ 16	$ 79
Net realized and unrealized losses (1)	134	15
Purchases	—	(1)
Issuances	—	(1)
Settlements	(1)	—
Net transfers out of Level 3 to Level 2	(10)	(76)
Net liabilities from price risk management activities as of end of year	$ 139	$ 16
Level 3 net unrealized losses that have been fully offset by the effect of regulatory accounting	$ 133	$ 14

(1) Includes realized losses, net of $1 million in 2013 and in 2012.

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, 2013 and 2012, there were no transfers into Level 3 from Level 2. Transfers out of Level 3 occur when the significant inputs become more observable, such as when the time between the valuation date and the delivery term of a transaction becomes shorter. PGE records transfers in and transfers out of Level 3 at the end of the reporting period for all of its financial 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 balance sheets. The fair value of long-term debt 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. As of December 31, 2013, the estimated aggregate fair value of PGE's long-term debt was $2,074 million, compared to its $1,916 million carrying amount. As of December 31, 2012, the estimated aggregate fair value of PGE's long-term debt was $1,949 million, compared to its $1,636 million carrying amount.

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 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,	
	2013	**2012**
Current assets:		
Commodity contracts:		
Electricity	$ 9	$ 1
Natural gas	4	3
Total current derivative assets	13	4
Noncurrent assets:		
Commodity contracts:		
Electricity	1	—
Natural gas	—	2
Total noncurrent derivative assets	1	2
Total derivative assets not designated as hedging instruments	$ 14	$ 6
Total derivative assets	$ 14	$ 6
Current liabilities:		
Commodity contracts:		
Electricity	$ 20	$ 44
Natural gas	29	83
Total current derivative liabilities	49	127
Noncurrent liabilities:		
Commodity contracts:		
Electricity	107	38
Natural gas	34	35
Total noncurrent derivative liabilities	141	73
Total derivative liabilities not designated as hedging instruments	$ 190	$ 200
Total derivative liabilities	$ 190	$ 200

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,					
	2013			2012		
Commodity contracts:						
Electricity		14	MWh		11	MWh
Natural gas		106	Dth		86	Dth
Foreign currency exchange	$	7	Canadian	$	7	Canadian

PGE has elected to report gross on the balance sheets 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 Balance Sheets		Net Amount
				Derivatives	Cash Collateral(1)	
As of December 31, 2013:						
Liabilities:						
Commodity contracts:						
Electricity(2)	$ 91	$ —	$ 91	$ (91)	$ —	$ —
Natural gas(2)	1	—	1	(1)	—	—
	$ 92	$ —	$ 92	$ (92)	$ —	$ —
As of December 31, 2012:						
Liabilities:						
Commodity contracts:						
Electricity(2)	$ 20	$ —	$ 20	$ (20)	$ —	$ —
Natural gas(2)	7	—	7	(7)	—	—
	$ 27	$ —	$ 27	$ (27)	$ —	$ —

(1) As of December 31, 2013 and 2012, the Company had collateral posted of $7 million and $18 million, respectively, which consists entirely of letters of credit.
(2) Included in Liabilities from price risk management activities—current and Liabilities from price risk management activities—noncurrent.

Net realized and unrealized losses on derivative transactions not designated as hedging instruments are classified in Purchased power in the statements of income and were as follows (in millions):

	Years Ended December 31,	
	2013	**2012**
Commodity contracts:		
Electricity	$ 78	$ 56
Natural Gas	28	19
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, 2013 and 2012, $120 million and $42 million, respectively, have been offset.

Assuming no changes in market prices and interest rates, the following table indicates the year in which the net unrealized loss recorded as of December 31, 2013 related to PGE's derivative activities would be realized as a result of the settlement of the underlying derivative instrument (in millions):

	2014	**2015**	**2016**	**2017**	**2018**	**Thereafter**	**Total**
Commodity contracts:							
Electricity	$ 11	$ 26	$ 12	$ 5	$ 5	$ 58	$ 117
Natural gas	25	10	14	10	—	—	59
Net unrealized loss	$ 36	$ 36	$ 26	$ 15	$ 5	$ 58	$ 176

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, 2013 was $186 million, for which the Company had posted $30 million in collateral, consisting primarily of letters of credit. If the credit-risk-related contingent features underlying these agreements were triggered at December 31, 2013, the cash requirement to either post as collateral or settle the instruments immediately would have been $181 million. As of December 31, 2013, PGE had posted an additional $9 million in cash collateral for derivative instruments with no credit-risk-related contingent features, which is classified as Special deposits on the Company's balance sheet.

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

	As of December 31,	
	2013	**2012**
Assets from price risk management activities:		
Counterparty A	53%	—%
Counterparty B	5	21
Counterparty C	5	11
Counterparty D	4	13
Counterparty E	—	10
	67%	55%
Liabilities from price risk management activities:		
Counterparty F	43%	—%
Counterparty G	11	—
Counterparty H	6	24
Counterparty I	5	10
Counterparty A	2	14
	67%	48%

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, 2013		As of December 31, 2012	
Regulatory assets:					
Price risk management (2)	6 years	$	176	$	194
Pension and other postretirement plans (2)	(3)		194		321
Deferred income taxes (2)	(4)		79		84
Deferred broker settlements (2)	1 year		13		20
Deferred capital projects	2 years		34		16
Other (5)	Various		20		11
Total regulatory assets		$	516	$	646
Regulatory liabilities:					
Trojan decommissioning activities	(6)		41		—
Asset retirement obligations (7)	(4)		39		39
Other	Various		31		34
Total regulatory liabilities		$	111	$	73

(1) As of December 31, 2013.
(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 $16 million and $11 million as of December 31, 2013 and 2012, respectively.
(6) Refund period not yet determined.
(7) Included in rate base for ratemaking purposes.

As of December 31, 2013, PGE had regulatory assets of $59 million earning a return on investment at the following rates: (i) $34 million at PGE's cost of debt of 6.065%; (ii) $15 million earning a return by inclusion in rate base; (iii) $9 million at the approved rate for deferred accounts under amortization, ranging from 1.38% to 2.24%, depending on the year of approval; and (iv) $1 million at PGE's cost of capital of 8.033%.

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 future customer prices is subject to a regulated earnings test and approval by the OPUC.

Trojan decommissioning activities represent a $44 million settlement for the reimbursement of certain monitoring costs incurred related to spent nuclear fuel at the Company's Trojan nuclear power plant (Trojan). The proceeds will benefit customers in future regulatory proceedings and offset amounts previously collected from customers in relation to Trojan decommissioning activities.

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,	
	2013	**2012**
Trojan decommissioning activities	$ 41	$ 42
Utility plant	49	39
Non-utility property	10	13
Asset retirement obligations	$ 100	$ 94

Trojan decommissioning activities represents the present value of future decommissioning expenditures 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 early 2012, and on November 30, 2012, the U.S. Court of Federal Claims issued a judgment awarding certain damages to the Plaintiffs. The judgment did not state the precise amount of the damages award, but directed the parties to consult and propose a final amount for the Plaintiffs' recovery that was based on certain adjustments specified in the court's ruling. In July 2013, the parties reached a settlement wherein the Trojan co-owners were to receive approximately $70 million for the period through 2009. PGE's share, approximately $44 million, was received during the third quarter 2013 and 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. The Trojan ARO is not impacted by the outcome of this case as such recovery is for past decommissioning costs and the ARO reflects only future decommissioning expenditures.

The settlement agreement also provided for a process to submit claims for allowable costs for the period 2010 through 2013. In January 2014, the settlement agreement was extended to cover costs through 2016. The Company will seek recovery of any costs for subsequent periods in future extensions of the agreement.

In October 2013, the Trojan co-owners submitted a claim for $9 million related to 2010 through 2012 costs, with PGE's share approximating $6 million. The Company expects to receive payment for the submitted claim in mid-2014.

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.

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

During 2011, an updated decommissioning study for PGE's Boardman coal-fired generating plant (Boardman) was completed, which included the assumption that Boardman's coal-fired operations cease in 2020 rather than 2040. As a result of the study, PGE increased its ARO related to Boardman by approximately $20 million, with a corresponding increase in the cost basis of the plant, included in Utility plant on the balance sheet. Furthermore, in December 2013, PGE increased the ARO by $4 million related to the acquisition of an additional 15% interest in Boardman.

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

	Years Ended December 31,	
	2013	**2012**
Balance as of beginning of year	$ 94	$ 87
Liabilities incurred	4	—
Liabilities settled	(4)	(3)
Accretion expense	6	6
Revisions in estimated cash flows	—	4
Balance as of end of year	$ 100	$ 94

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, currently at approximately $4 million annually, with an equal amount recorded in Depreciation and amortization expense.

PGE maintains a separate trust account, Nuclear decommissioning trust in the balance sheet, for funds collected from customers through prices to cover the cost of Trojan decommissioning activities. See "*Trust Accounts*" in Note 3, 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 syndicated unsecured revolving credit facility, which is scheduled to terminate in November 2018; and
- A $300 million syndicated unsecured 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, 2013, PGE was in compliance with this covenant with a 51.3% debt to total capital ratio.

PGE classifies any borrowings under the revolving credit facilities and outstanding commercial paper as Short-term debt in the balance sheets. As of December 31, 2013, PGE had no borrowings or commercial paper outstanding, $37 million of letters of credit issued, and an aggregate available capacity of $663 million under the revolving credit facilities.

PGE also has two one-year $30 million letter of credit facilities, which are scheduled to terminate in September and October 2014. As of December 31, 2013, PGE had issued an additional $37 million of letters of credit under the facilities, with an aggregate available capacity of $23 million 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,	
	2013	2012
Average daily amount of short-term debt outstanding	$ 9	$ 4
Weighted daily average interest rate *	0.4%	0.4%
Maximum amount outstanding during the year	$ 54	$ 44

* 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,	
	2013	2012
First Mortgage Bonds, rates range from 3.46% to 9.31%, with a weighted average rate of 5.62% in 2013 and 5.84% in 2012, due at various dates through 2048	$ 1,795	$ 1,515
Pollution Control Revenue Bonds, 5% rate, due 2033	148	142
Pollution Control Revenue Bonds owned by PGE	(27)	(21)
Total long-term debt	$ 1,916	$ 1,636

First Mortgage Bonds—During 2013, PGE repaid a total of $100 million of First Mortgage Bonds (FMBs), in accordance with the terms of the debt agreements, and issued a total of $380 million of FMBs, consisting of the following:

- In April, repaid $50 million of 4.45% Series FMBs;
- In June, issued $150 million of 4.47% Series FMBs due 2044;
- In August, repaid $50 million of 5.625% Series FMBs and issued $75 million of 4.47% Series FMBs due 2043;
- In November, issued $105 million of 4.74% Series FMBs due 2042; and
- In December, issued $50 million of 4.84% Series FMBs due 2048.

The Indenture securing PGE’s outstanding FMBs constitutes a direct first mortgage lien on substantially all regulated utility property, other than expressly excepted property.

Pollution Control Revenue Bonds—Of the $27 million of Pollution Control Bonds held by the Company, PGE has the option to remarket $21 million through 2033. The Company retired $6 million of Pollution Control Bonds in January 2014. At the time of any remarketing, PGE 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 Pollution Control Revenue Bonds could be backed by FMBs or a bank letter of credit depending on market conditions.

As of December 31, 2013, the future minimum principal payments on long-term debt are as follows (in millions):

Years ending December 31:		
2015	$	70
2016		67
2017		58
2018		75
Thereafter		1,646
	$	1,916

Interest is payable semi-annually on all long-term debt instruments.

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 2013 and 2012. No contributions to the pension plan are expected in 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 PGE's balance sheets are as follows as of December 31 (in millions):

	2013			**2012**		
	NQBP	**Other NQBP**	**Total**	**NQBP**	**Other NQBP**	**Total**
Non-qualified benefit plan trust	$ 16	$ 19	$ 35	$ 15	$ 17	$ 32
Non-qualified benefit plan liabilities	24	79	103	27	77	102

See "*Trust Accounts*" in Note 3, 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,			
	2013		2012	
	Actual	Target *	Actual	Target *
Defined Benefit Pension Plan:				
Equity securities	67%	67%	68%	67%
Debt securities	33	33	32	33
Total	100%	100%	100%	100%
Other Postretirement Benefit Plans:				
Equity securities	58%	58%	63%	72%
Debt securities	42	42	37	28
Total	100%	100%	100%	100%
Non-Qualified Benefits Plans:				
Equity securities	24%	16%	17%	17%
Debt securities	1	9	6	10
Insurance contracts	75	75	77	73
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, 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
As of December 31, 2012:				
Defined Benefit Pension Plan assets:				
Money market funds	$ —	$ 1	$ —	$ 1
Equity securities:				
Domestic	150	15	—	165
International	166	—	—	166
Debt securities:				
Domestic government and corporate credit	—	165	—	165
Corporate credit	8	—	—	8
Private equity funds	—	—	32	32
	$ 324	$ 181	$ 32	$ 537
Other Postretirement Benefit Plans assets:				
Money market funds	$ —	$ 8	$ —	$ 8
Equity securities:				
Domestic	8	1	—	9
International	8	—	—	8
Debt securities—Domestic government	3	—	—	3
	$ 19	$ 9	$ —	$ 28

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 primarily classified as Level 1 securities based on unadjusted prices in an active market. Principal markets for equity prices include published exchanges such as NASDAQ and NYSE. Certain 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 were as follows (in millions):

	Years Ended December 31,			
	2013	2012		
	Private equity funds	Private equity funds	Alternative investments	Total
Level 3 balance as of beginning of year	$ 32	$ 32	$ 30	$ 62
Unrealized gains (losses), net	4	2	(6)	(4)
Realized gains (losses), net	(2)	(1)	6	5
Sales, net	(3)	(1)	(30)	(31)
Level 3 balance as of end of year	$ 31	$ 32	$ —	$ 32

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, 2013 and 2012. 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	
	2013	2012	2013	2012	2013	2012
Benefit obligation:						
As of January 1	$ 728	$ 634	$ 84	$ 75	$ 27	$ 27
Service cost	17	14	2	2	—	—
Interest cost	30	31	3	3	1	1
Participants' contributions	—	—	2	2	—	—
Actuarial (gain) loss	(38)	77	(9)	7	(2)	1
Contractual termination benefits	—	—	1	1	—	—
Benefit payments	(32)	(28)	(6)	(6)	(2)	(2)
As of December 31	$ 705	$ 728	$ 77	$ 84	$ 24	$ 27
Fair value of plan assets:						
As of January 1	$ 537	$ 487	$ 28	$ 27	$ 15	$ 17
Actual return on plan assets	91	78	5	3	3	—
Company contributions	—	—	3	2	—	—
Participants' contributions	—	—	2	2	—	—
Benefit payments	(32)	(28)	(6)	(6)	(2)	(2)
As of December 31	$ 596	$ 537	$ 32	$ 28	$ 16	$ 15
Unfunded position as of December 31	$ (109)	$ (191)	$ (45)	$ (56)	$ (8)	$ (12)
Accumulated benefit plan obligation as of December 31	$ 631	$ 640	N/A	N/A	$ 24	$ 27
Amounts included in comprehensive income:						
Net actuarial (gain) loss	$ (89)	$ 40	$ (11)	$ 5	$ (1)	$ 2
Amortization of net actuarial loss	(24)	(17)	(1)	(1)	(1)	(1)
Amortization of prior service cost	—	—	(1)	(1)	—	—
	$ (113)	$ 23	$ (13)	$ 3	$ (2)	$ 1
Amounts included in AOCL*:						
Net actuarial loss	$ 186	$ 298	$ 6	$ 18	$ 9	$ 11
Prior service cost	—	1	2	4	—	—
	$ 186	$ 299	$ 8	$ 22	$ 9	$ 11
Assumptions used:						
Discount rate for benefit obligation	4.84%	4.24%	3.46%- 4.96%	2.77%- 4.13%	4.84%	4.24%

Discount rate for benefit cost	4.24%	5.00%	2.77%- 4.13%	3.76%- 4.90%	4.24%	5.00%
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%	3.71%	4.58%	4.58%	N/A	N/A
Long-term rate of return on plan assets for benefit obligation	7.50%	8.25%	6.46%	6.50%	N/A	N/A
Long-term rate of return on plan assets for benefit cost	8.25%	8.25%	5.89%	7.09%	N/A	N/A

* Amounts included in AOCL related to the Company's defined benefit pension plan and other postretirement benefits are transferred to Regulatory assets due to the future recoverability from retail customers. Accordingly, as of the balance sheet date, such amounts are included in 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	
	2013	**2012**	**2013**	**2012**	**2013**	**2012**
Service cost	$ 17	$ 14	$ 2	$ 2	$ —	$ —
Interest cost on benefit obligation	30	31	3	3	1	1
Expected return on plan assets	(40)	(41)	(1)	(1)	—	—
Amortization of prior service cost	—	—	1	1	—	—
Amortization of net actuarial loss	24	17	1	1	1	1
Net periodic benefit cost	$ 31	$ 21	$ 6	$ 6	$ 2	$ 2

PGE estimates that $20 million will be amortized from AOCL into net periodic benefit cost in 2014, consisting of a net actuarial loss of $17 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.

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					
	2014	**2015**	**2016**	**2017**	**2018**	**2019 - 2023**
Defined benefit pension plan	$ 34	$ 36	$ 37	$ 39	$ 40	$ 219
Other postretirement benefits	5	5	5	5	5	26
Non-qualified benefit plans	2	2	2	2	2	10
Total	$ 41	$ 43	$ 44	$ 46	$ 47	$ 255

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 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; and

- For 2012, 8% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2013, 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 bargaining employees, who are subject to the International Brotherhood of Electrical Workers Local 125 agreements, the Company contributes 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 2013 and 2012.

NOTE 11: INCOME TAXES

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

	Years Ended December 31,	
	2013	**2012**
Current:		
Federal	$ 10	$ 16
State and local	—	1
	10	17
Deferred:		
Federal	4	30
State and local	7	17
	11	47
Income tax expense	$ 21	$ 64

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,	
	2013	**2012**
Federal statutory tax rate	35.0%	35.0%
Federal tax credits	(21.8)	(11.8)
State and local taxes, net of federal tax benefit	3.4	3.5
Adjustment to deferred taxes for change in blended composite state tax rate	—	2.6
Flow through depreciation and cost basis differences	2.8	2.4
Other	(2.6)	(0.6)
Effective tax rate	16.8%	31.1%

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

	As of December 31,	
	2013	**2012**
Deferred income tax assets:		
Employee benefits	$ 124	$ 163
Price risk management	76	80
Tax credits	51	55
Regulatory liabilities	16	21
Depreciation and amortization	5	9
Other	33	12
Total deferred income tax assets	305	340
Deferred income tax liabilities:		
Depreciation and amortization	651	632
Regulatory assets	175	224
Price risk management	6	3
Employee Benefits	2	1
Other	15	17
Total deferred income tax liabilities	849	877
Deferred income tax liability, net	$ (544)	$ (537)

As of December 31, 2013, PGE has federal and state tax credit carryforwards of $40 million and $11 million, respectively, which will expire at various dates from 2016 through 2035.

PGE believes that it is more likely than not that its deferred income tax assets as of December 31, 2013 and 2012 will be realized; accordingly, no valuation allowance has been recorded.

As of December 31, 2013 and 2012, PGE had no unrecognized tax benefits.

PGE and its subsidiaries file consolidated 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.

On September 13, 2013, the U.S. Department of Treasury and the IRS issued final regulations regarding the deduction and capitalization of expenditures related to tangible property. The final regulations under Internal Revenue Code Section 162, 167 and 263(a) apply to amounts paid to acquire, produce, or improve tangible property, as well as dispositions of such property and are generally effective for tax years beginning on or after January 1, 2014. The Company has evaluated these regulations and has determined they will not have a material impact on its financial position, results of operations, or cash flows.

NOTE 12: EQUITY-BASED PLANS

Equity Forward Sale Agreement

On June 11, 2013, PGE entered into an equity forward sale agreement (EFSA) in connection with a public offering of 11,100,000 shares of its common stock. The underwriters exercised their over-allotment option in full in connection with such public offering and on June 17, 2013, PGE separately issued 1,665,000 shares of PGE common stock for $28.54 per share, net of the underwriters' discount, or net proceeds of $47 million. In August, the Company issued 700,000 shares for net proceeds of $20 million pursuant to the EFSA.

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 records the proceeds in equity.

Under the terms of the EFSA, PGE may elect to settle the equity forward transactions by means of: (1) physical; (2) cash; or (3) 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 use of the EFSA substantially eliminates future equity market price risk by fixing the common stock offering sales price under the then existing market conditions, while mitigating immediate share dilution resulting from the offering by postponing the actual issuance of common stock until such funds are needed in accordance with the Company's capital requirements. The EFSA had no initial fair value since it was entered into at the then market price of the common stock. PGE concluded that the EFSA was an equity instrument and that it 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.

At December 31, 2013, the Company could have physically settled the EFSA by delivering 10,400,000 shares to the forward counterparty in exchange for cash of $288 million. In addition, at December 31, 2013, the Company could have elected to make a cash settlement by paying approximately $26 million, or a net share settlement by delivering approximately 876,318 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, 2013, there were 451,506 shares available for future issuance pursuant to the ESPP.

Dividend Reinvestment and Direct Stock Purchase Plan

On April 1, 2011, PGE's Dividend Reinvestment and Direct Stock Purchase Plan (DRIP) became effective, 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, 2013, there were 2,485,055 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 with time-based vesting conditions and performance-based vesting conditions to non-employee directors, officers and certain key employees. Service requirements generally must be met for stock units to vest. For each grant, the number of restricted stock units is determined by dividing the specified award amount for each grantee by the closing stock price on the date of grant. A total of 4,687,500 shares of common stock were registered for future issuance under the Plan, of which 3,701,833 shares remain available for future issuance as of December 31, 2013.

Time-based restricted stock units 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.

Performance-based restricted stock units 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 total shareholder return (TSR) relative to the Edison Electric Institute Regulated Index (EEI Index). Vesting of performance-based restricted stock units 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.

Outstanding restricted stock units 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 stock units. 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 restricted stock unit grants) 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.

Restricted stock unit activity is summarized in the following table:

	Units	Weighted Average Grant Date Fair Value
Outstanding as of December 31, 2011	491,404	18.54
Granted	186,495	24.72
Forfeited	(22,947)	18.95
Vested	(214,390)	15.67
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

The Company withholds a portion of the vested shares for the payment of income taxes on behalf of the employees. The total value of time- and performance-based stock units vested during the years ended December 31, 2013 and 2012 was $4 million and $3 million, respectively. The weighted average fair value of the return on equity and regulated asset base growth portions of the grants is measured based on the closing price of PGE common stock on the date of grant. The fair value of these awards is charged to compensation expense over the requisite service period 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 110.7% and 109.2% of awarded performance-based restricted stock units for 2013 and 2012, respectively, with an estimated 5% forfeiture rate. The weighted average fair value of the TSR portion 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 estimated TSR grant date fair value is 99.7% of the grant price. The fair value of these awards is charged to compensation expense over the requisite service period, regardless of the level of TSR metric actually attained. The assumptions used in the Monte Carlo model are summarized as follows:

	2013
Stock price at March 5, 2013	$ 30.29
Risk-free rate	0.34%
Expected term (in years)	3
Expected volatility	16.77%
Range of expected volatility for EEI Index	12.06% - 25.13%
Dividend yield	0%

For the years ended December 31, 2013 and 2012, PGE recorded stock-based compensation expense of $4 million, which is included in Administrative and general expenses in the statements of income. Such amounts differ from those reported in the statements of equity for Stock-based compensation due primarily to the impact from the income tax payments made on behalf of 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 $2 million in 2013 and $1 million in 2012, which is not included in Administrative and general expenses in the statements of income.

As of December 31, 2013, unrecognized stock-based compensation expense was $4 million, of which approximately $3 million and $1 million is expected to be expensed in 2014 and 2015, 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, 2013 or 2012.

NOTE 14: COMMITMENTS AND GUARANTEES

Commitments

As of December 31, 2013, PGE's estimated future minimum payments pursuant to purchase obligations for the following five years and thereafter are as follows (in millions):

	Payments Due						
	2014	**2015**	**2016**	**2017**	**2018**	**Thereafter**	**Total**
Capital and other purchase commitments	$ 710	$ 113	$ 40	$ 2	$ 2	$ 67	$ 934
Purchased power and fuel:							
Electricity purchases	240	159	150	125	126	683	1,483
Capacity contracts	22	23	22	2	2	1	72
Public Utility Districts	8	8	7	5	5	33	66
Natural gas	65	21	12	10	8	6	122
Coal and transportation	21	6	6	6	4	5	48
Operating leases	11	9	10	10	10	191	241
Total	$ 1,077	$ 339	$ 247	$ 160	$ 157	$ 986	$ 2,966

Capital and other purchase commitments—Certain commitments have been made for capital and other purchases for 2014 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 2014 and 2015 are costs associated with the construction of three new generating facilities. 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 2037, 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 $1 million that settle in 2014.

Public Utility Districts—PGE has long-term power purchase contracts with certain public utility districts in the state of Washington and with the City of Portland, Oregon. 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, 2013	PGE's Share in 2013 Output	PGE's Share in 2013 Capacity (in MW)	Contract Expiration	PGE Cost, including Debt Service 2013	PGE Cost, including Debt Service 2012
Priest Rapids and Wanapum	$ 1,001	9.0%	170	2052	$ 14	$ 14
Wells	232	19.4	150	2018	10	10
Portland Hydro	7	100.0	36	2017	4	4

Under contracts with the public utility districts, PGE has acquired a percentage of the output (Allocation) of Priest Rapids and Wanapum and Wells. The contracts 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 Allocation. 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, which expires in April 2017, for the purpose of fueling the Company's Port Westward natural gas-fired generating plant (Port Westward) and Beaver natural gas-fired generating plant (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 Port Westward and Beaver are located, which expires in 2096. Rent expense was $9 million in 2013 and $10 million in 2012.

The future minimum operating lease payments presented is net of sublease income of: $3 million in 2014 and 2015; $2 million in 2016; and $1 million in 2017 and 2018. Sublease income was $3 million in 2013 and 2012.

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, 2013, 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 balance sheets 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 expense categories in the statements 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 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. 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.

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 is estimated at $96 million and $2 million, respectively. The Purchaser is not a public utility so PGE utilized its records as the operator of the plant to estimate the original cost. It is also estimated that these assets were fully depreciated at the time of the acquisition 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 will be submitted to the FERC no later than June 30th, 2014, in compliance with the accounting under the Uniform System of Accounts. Following FERC approval, the proposed accounting entries will be executed which will increase both FERC Account 101, Electric plant in service, and FERC Account 108, Accumulated provision for depreciation, by the estimated $98 million with corresponding offsets to Account 102, Electric plant purchased or sold.

As of December 31, 2013, 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	80.00%	1980	$ 506	$ 326	$ 1
Colstrip	20.00	1986	515	332	3
Pelton/Round Butte	66.67	1958 / 1964	222	52	15
Total			$ 1,243	$ 710	$ 19

* 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.

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 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. Opening briefs have been filed and oral argument occurred March 4, 2014.

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.

As noted above, on February 6, 2013, the Oregon Court of Appeals upheld the 2008 Order. Because the Oregon Supreme Court has granted the plaintiffs' petition seeking review of that decision, and the class actions described above remain pending, management believes that it is reasonably possible that the regulatory proceedings and class actions could result in a loss to the Company in excess of the amounts previously recorded and discussed above. Because these matters involve unsettled legal theories and have a broad range of potential outcomes, sufficient information is currently not available to determine PGE's potential liability, if any, 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. In 2003, the FERC issued an order terminating the proceeding and denying the claims for refunds. Parties appealed various aspects of the FERC order to the U.S. Ninth Circuit Court of Appeals (Ninth Circuit).

In August 2007, the Ninth Circuit issued a decision, concluding that the FERC failed to adequately explain how it considered or examined new evidence showing intentional market manipulation in California and the potential ties to the Pacific Northwest and that the FERC should not have excluded from the Pacific Northwest Refund proceeding purchases of energy made by the California Energy Resources Scheduling (CERS) division in the Pacific Northwest spot market. The Ninth Circuit remanded the case to the FERC to: i) address the new market manipulation evidence in detail and account for the evidence in any future orders regarding the award or denial of refunds in the proceedings; ii) include sales to CERS in its analysis; and iii) further consider its refund decision in light of related, intervening opinions of the court. The Ninth Circuit offered no opinion on the FERC's findings based on the record established by the administrative law judge and did not rule on the FERC's ultimate decision to deny refunds. After denying requests for rehearing, the Ninth Circuit in April 2009 issued a mandate giving immediate effect to its August 2007 order remanding the case to the FERC.

In October 2011, the FERC issued an Order on Remand, establishing an evidentiary hearing to determine whether any seller had engaged in unlawful market activity in the Pacific Northwest spot markets during the December 25, 2000 through June 20, 2001 period by violating specific contracts or tariffs, and, if so, whether a direct connection existed between the alleged unlawful conduct and the rate charged under the applicable contract. The FERC 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 before a refund could be ordered. 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. Certain parties claiming refunds filed requests for rehearing of the Order on Remand.

In December 2012, the FERC issued an order granting an interlocutory appeal of the trial judge's ruling on the scope of the remand proceeding. In this order, the FERC held that its Order on Remand was not intended to alter the general state of the law regarding the *Mobile-Sierra* presumption. The FERC clarified that the *Mobile-Sierra* presumption could be 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.

On April 5, 2013, and subject to its December 2012 clarification in the interlocutory appeal, the FERC denied rehearing requests from refund proponents that had contested the FERC's use of the *Mobile-Sierra* standard in the remand proceeding, its denial of a market-wide remedy, and the restraints in the Order on Remand that limited the types of evidence that could be introduced in the hearing. However, the FERC granted rehearing on the issue of the appropriate refund period, holding that parties could 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. Refund claimants have filed petitions for appeal of the Order on Remand and the Order on Rehearing with the Ninth Circuit.

In its October 2011 Order on Remand, the FERC ordered settlement discussions to be convened before a FERC settlement judge. Pursuant to the settlement proceedings, 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 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 for the Company as a named respondent in the ongoing 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 future proceedings if refunds are ordered against current respondents.

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, which contracts would be subject to refunds, the basis on which refunds would be ordered, or how such refunds, if any, would be calculated. 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 expected to issue in 2015 or 2016.

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, is expected to be submitted to the DEQ in late February 2014. Using the Company's best estimate of the probable cost for the remediation effort from the set of alternatives provided in the draft feasibility study report, PGE recorded a $3 million reserve for this matter as of December 31, 2013.

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 recorded a regulatory asset of $3 million for future recovery in prices as of December 31, 2013. The Company included recovery of the regulatory asset in its 2015 General Rate Case filed with the OPUC in February 2014.

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 the 39 claims in the suit. On September 27, 2013, the plaintiffs filed an amended complaint that deleted the 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. This matter is scheduled for trial in March 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.

Challenge to AOC Related to Colstrip Wastewater Facilities

In August 2012, the operator of CSES entered into an AOC with the MDEQ, which established a comprehensive process to investigate and remediate groundwater seepage impacts related to the wastewater facilities at CSES. Within five years, under this AOC, the operator of CSES is required to provide financial assurance to MDEQ for the costs associated with closure of the waste water treatment facilities. This will establish an obligation for asset retirement, but the operator of CSES is unable at this time to estimate these costs, which will require both public and agency review.

In September 2012, Earthjustice filed an affidavit pursuant to Montana's Major Facility Siting Act (MFSA) that sought review of the AOC by Montana's Board of Environmental Review (BER), on behalf of environmental groups Sierra Club, the MEIC, and the National Wildlife Federation. In September 2012, the operator of CSES filed an election with the BER to have this proceeding conducted in Montana state district court as contemplated by the MFSA. In October

2012, Earthjustice, on behalf of Sierra Club, the MEIC and the National Wildlife Federation, filed with the Montana state district court a petition for a writ of mandamus and a complaint for declaratory relief alleging that the AOC fails to require the necessary actions under the MFSA and the Montana Water Quality Act with respect to groundwater seepage from the wastewater facilities at CSES. On May 31, 2013, the district court judge granted the defendants' motion to dismiss the petition for the writ of mandamus.

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.

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. For open tax years per Oregon statute, 2008 through 2012, the Company entered into a closing agreement with the DOR during the third quarter 2013 under which the DOR agreed to the tax apportionment methodology utilized on the tax returns relating to those years. PGE cannot predict the outcome of this matter.

Other Matters

PGE is subject to other regulatory, environmental, and legal proceedings, investigations, and claims that arise from time to time in the ordinary course of business, which may result in judgments against the Company. Although management currently believes that resolution of such matters will not have a material impact on its financial position, results of operations, or cash flows, these matters are subject to inherent uncertainties, and management's view of these matters may change in the future.

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				(6,078,181)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				(297,809)
3	Preceding Quarter/Year to Date Changes in Fair Value				
4	Total (lines 2 and 3)				(297,809)
5	Balance of Account 219 at End of Preceding Quarter/Year				(6,375,990)
6	Balance of Account 219 at Beginning of Current Year				(6,375,990)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				1,314,010
8	Current Quarter/Year to Date Changes in Fair Value				
9	Total (lines 7 and 8)				1,314,010
10	Balance of Account 219 at End of Current Quarter/Year				(5,061,980)

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)		(6,078,989)	[redacted]	[redacted]
2			(297,809)	[redacted]	[redacted]
3				[redacted]	[redacted]
4			(297,809)		(297,809)
5	(808)		(6,376,798)	[redacted]	[redacted]
6	(808)		(6,376,798)	[redacted]	[redacted]
7			1,314,010	[redacted]	[redacted]
8				[redacted]	[redacted]
9			1,314,010		1,314,010
10	(808)		(5,062,788)	[redacted]	[redacted]

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

Comprised of the net amount of the actuarial valuation of $580,081 of non-qualified benefit plans net of taxes of $(282,272).

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

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 2013/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)	7,086,611,503	7,086,611,503
4	Property Under Capital Leases		
5	Plant Purchased or Sold	-1	-1
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	7,086,611,502	7,086,611,502
9	Leased to Others		
10	Held for Future Use	3,872,278	3,872,278
11	Construction Work in Progress	507,603,106	507,603,106
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	7,598,086,886	7,598,086,886
14	Accum Prov for Depr, Amort, & Depl	3,469,615,339	3,469,615,339
15	Net Utility Plant (13 less 14)	4,128,471,547	4,128,471,547
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	3,299,660,915	3,299,660,915
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	169,954,424	169,954,424
22	Total In Service (18 thru 21)	3,469,615,339	3,469,615,339
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)	3,469,615,339	3,469,615,339

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 2013/Q4

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
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					33

Schedule Page: 200 Line No.: 5 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 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 is estimated at $96 million and $2 million, respectively. It is 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 will be submitted to the FERC no later than June 30th, 2014, in compliance with the accounting under the Uniform System of Accounts. Following FERC approval, the proposed accounting entries will be executed which will increase both FERC Account 101, Electric plant in service, and FERC Account 108, Accumulated provision for depreciation, by the estimated $98 million with corresponding offsets to Account 102, Electric plant purchased or sold.

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 2013/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)		

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 2013/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/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	144,231,676	1,483,984
4	(303) Miscellaneous Intangible Plant	212,946,638	30,508,354
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	357,178,314	31,992,338
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	4,160,671	
9	(311) Structures and Improvements	218,471,821	1,804,966
10	(312) Boiler Plant Equipment	453,956,844	35,388,871
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	165,500,957	19,871
13	(315) Accessory Electric Equipment	47,139,154	1,248
14	(316) Misc. Power Plant Equipment	12,149,422	279,277
15	(317) Asset Retirement Costs for Steam Production	24,903,797	7,212,083
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	926,282,666	44,706,316
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	47,923,594	1,464,154
29	(332) Reservoirs, Dams, and Waterways	255,948,831	17,712,078
30	(333) Water Wheels, Turbines, and Generators	51,942,365	759,223
31	(334) Accessory Electric Equipment	16,563,253	236,762
32	(335) Misc. Power PLant Equipment	1,853,415	245,879
33	(336) Roads, Railroads, and Bridges	9,762,959	281,021
34	(337) Asset Retirement Costs for Hydraulic Production	4,276	852
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	390,046,320	20,699,969
36	D. Other Production Plant		
37	(340) Land and Land Rights	48,946	
38	(341) Structures and Improvements	115,942,664	414,336
39	(342) Fuel Holders, Products, and Accessories	115,850,099	1,623,921
40	(343) Prime Movers		
41	(344) Generators	1,268,110,695	4,132,105
42	(345) Accessory Electric Equipment	65,560,346	1,538,673
43	(346) Misc. Power Plant Equipment	10,166,833	824,217
44	(347) Asset Retirement Costs for Other Production	2,213,948	-650,578
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	1,577,893,531	7,882,674
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	2,894,222,517	73,288,959

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	11,230,108	
49	(352) Structures and Improvements	17,407,070	748,192
50	(353) Station Equipment	241,319,092	5,081,873
51	(354) Towers and Fixtures	46,808,292	
52	(355) Poles and Fixtures	20,460,356	331,489
53	(356) Overhead Conductors and Devices	74,129,949	2,527
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	53,039	-18,930
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	411,694,238	6,145,151
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	20,358,925	151
61	(361) Structures and Improvements	36,822,187	1,471,699
62	(362) Station Equipment	384,524,570	31,141,546
63	(363) Storage Battery Equipment		351,741
64	(364) Poles, Towers, and Fixtures	325,204,225	15,767,988
65	(365) Overhead Conductors and Devices	533,059,151	19,277,321
66	(366) Underground Conduit	15,523,586	
67	(367) Underground Conductors and Devices	624,820,669	20,708,668
68	(368) Line Transformers	306,548,578	17,343,238
69	(369) Services	378,001,520	21,806,301
70	(370) Meters	125,718,827	5,461,098
71	(371) Installations on Customer Premises	376,133	
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	58,320,928	6,077,387
74	(374) Asset Retirement Costs for Distribution Plant	460,131	16,601
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	2,809,739,430	139,423,739
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	7,195,881	
87	(390) Structures and Improvements	70,923,192	27,620,580
88	(391) Office Furniture and Equipment	66,649,429	24,511,762
89	(392) Transportation Equipment	40,905,328	2,980,969
90	(393) Stores Equipment	2,851,686	10,920
91	(394) Tools, Shop and Garage Equipment	11,124,759	2,125,442
92	(395) Laboratory Equipment	9,949,816	58,652
93	(396) Power Operated Equipment	44,800,296	2,690,606
94	(397) Communication Equipment	72,606,946	12,839,460
95	(398) Miscellaneous Equipment	129,175	34,142
96	SUBTOTAL (Enter Total of lines 86 thru 95)	327,136,508	72,872,533
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant	64,488	801
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	327,200,996	72,873,334
100	TOTAL (Accounts 101 and 106)	6,800,035,495	323,723,521
101	(102) Electric Plant Purchased (See Instr. 8)	-232,078	-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)	6,799,803,417	323,723,520

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
			145,715,660		3
3,281,868			240,173,124		4
3,281,868			385,888,784		5
					6
					7
			4,160,671		8
207,042			220,069,745		9
2,827,405		3,113,207	489,631,517		10
					11
432,833		-3,113,207	161,974,788		12
			47,140,402		13
			12,428,699		14
			32,115,880		15
3,467,280			967,521,702		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			6,047,627		27
			49,387,748		28
51,669			273,609,240		29
108,893			52,592,695		30
9,593			16,790,422		31
			2,099,294		32
902			10,043,078		33
			5,128		34
171,057			410,575,232		35
					36
			48,946		37
8,329			116,348,671		38
141,632			117,332,388		39
					40
638,128			1,271,604,672		41
1			67,099,018		42
29,900			10,961,150		43
			1,563,370		44
817,990			1,584,958,215		45
4,456,327			2,963,055,149		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
		278,500	11,508,608		48
5,503			18,149,759		49
987,532		50	245,413,483		50
			46,808,292		51
17,925			20,773,920		52
			74,132,476		53
					54
					55
			286,332		56
			34,109		57
1,010,960		278,550	417,106,979		58
					59
35,809		1,283,589	21,606,856		60
74,011		-20,928	38,198,947		61
2,746,967		-834,236	412,084,913		62
			351,741		63
1,069,434		4,262	339,907,041		64
1,165,654		852,261	552,023,079		65
60,461			15,463,125		66
349,838			645,179,499		67
835,971		-1,409	323,054,436		68
131,301			399,676,520		69
733,193			130,446,732		70
			376,133		71
					72
4,174,577			60,223,738		73
			476,732		74
11,377,216		1,283,539	2,939,069,492		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
445,347			6,750,534		86
2,618,824			95,924,948		87
9,594,537			81,566,654		88
2,253,960			41,632,337		89
7,794			2,854,812		90
331,570			12,918,631		91
118,988			9,889,480		92
2,806,201			44,684,701		93
317,797			85,128,609		94
88,213			75,104		95
18,583,231			381,425,810		96
					97
			65,289		98
18,583,231			381,491,099		99
38,709,602		1,562,089	7,086,611,503		100
		232,078	-1		101
					102
					103
38,709,602		1,794,167	7,086,611,502		104

Schedule Page: 204 Line No.: 101 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 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 is estimated at $96 million and $2 million, respectively. It is also estimated that these assets were fully deperciated 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 will be submitted to the FERC no later than June 30th, 2014, in compliance with the accounting under the Uniform System of Accounts. Following FERC approval, the proposed accounting entries will be executed which will increase both FERC Account 101, Electric plant in service, as an addition in the appropriate 300 level accounts, and FERC Account 108, Accumulated provision for depreciation, by the estimated $98 million, with corresponding offsets to Account 102, Electric plant purchased or sold.

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

PGE received approval from the FERC April 4, 2013 through Docket AC12-135 to clear the account 102 Electric Plant Sold balance to account 254, Other Regulatory Liabilities. The balance in this account represented the sale of a 1.75 MW Solar facility in January 2012 between PGE and Bank of America Leasing & Capital LLC (BALC). PGE received regulatory approval for the sale from the Oregon Public Utility Commission in January 2012 through OPUC Order 12-006.

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 2013/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
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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	2,804,849
4	Sewell Easement, Washington County, OR	2009	2020	334,928
5				
6	Other Land and Land Rights (8 in Number)	Various	Various	188,910
7				
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				
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42				
43				
44				
45				
46				
47	Total			3,872,278

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 2013/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	Port Westward 2 Generating Plant Construction	161,649,424
2	Carty Generating Plant Construction	137,741,901
3	Tucannon River Wind Facility Construction	98,940,954
4	Clackamas River - Fish Passage Improvements	13,071,534
5	2020 Vision Wave 2 Software Project - MMS, GIS, OMS	12,334,311
6	IT Cyber Security Improvements	9,392,854
7	Bell Substation - Increase Site Capacity	9,135,999
8	Tri-Met Bridge 115-kV Line Construction	5,965,086
9	Round Butte - Rewind Generators #2 and #3	5,671,022
10	Underground Core Crew Building - Purchase / Remodel	5,620,248
11	Voice Systems Replacement Project	5,011,555
12	Pelton / Round Butte - Licensing Requirements	4,649,242
13	Clackamas River - Licensing Requirements	2,832,979
14	Customer Information System - Software Purchase And Implementation	2,303,779
15	MyPGE Employee Portal - Software Purchase And Implementation	2,097,977
16	Round Butte - Switchyard Upgrades	2,031,896
17	River District Infrastructure - Install Vaults And Conduits	1,852,581
18	Colstrip Capital Projects	1,646,088
19	Dispatchable Standby Generation Projects	1,643,482
20	Interval Data Billing - Software Purchase And Implementation	1,570,481
21	Boardman - Install Fire Detection System	1,418,968
22	PGE Company Website Upgrades	1,305,165
23	Postal Sortation (IPPD) - Software Purchase And Implementation	1,240,026
24	Colstrip - Unit 4 Generator Repair	1,125,842
25	Substation Fitness Upgrades	1,121,429
26		
27	Minor Projects < 1,000,000 - Represents 3% Of CWIP Balance	16,228,283
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	507,603,106

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.: 16 Column: a

Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. Respondent's 76% 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.

Schedule Page: 216 Line No.: 21 Column: a

Jointly owned with Idaho Power Company and Power Resources Cooperative. Respondent's 80% share of the joinly owned costs is reported.

Schedule Page: 216 Line No.: 24 Column: a

Jointly owned with Northwestern Energy, LLC, PP&L Montana, LLC, Puget Sound Energy, Inc., PacificCorp, and Avista Corporation. Respondents 20% share of jointly owned costs is reported.

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

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

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	3,099,402,013	3,099,402,013		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	228,686,066	228,686,066		
4	(403.1) Depreciation Expense for Asset Retirement Costs	3,771,528	3,771,528		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	3,902,499	3,902,499		
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)	236,621,445	236,621,445		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	34,946,578	34,946,578		
13	Cost of Removal	3,852,376	3,852,376		
14	Salvage (Credit)	1,397,478	1,397,478		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	37,401,476	37,401,476		
16	Other Debit or Cr. Items (Describe, details in footnote):	1,038,933	1,038,933		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	3,299,660,915	3,299,660,915		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	652,228,215	652,228,215		
21	Nuclear Production				
22	Hydraulic Production-Conventional	155,960,703	155,960,703		
23	Hydraulic Production-Pumped Storage				
24	Other Production	463,146,169	463,146,169		
25	Transmission	187,689,869	187,689,869		
26	Distribution	1,686,819,395	1,686,819,395		
27	Regional Transmission and Market Operation				
28	General	153,816,564	153,816,564		
29	TOTAL (Enter Total of lines 20 thru 28)	3,299,660,915	3,299,660,915		

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

1. PGE completed sale of the Merritt Building to Tri-Met in the first quarter of 2013 as agreed to per OPUC Order 13-006. The amount of $272,155 represents the remaining net plant reclassified to FERC 186 - Miscellaneous deferred debits, to offset any gain on sale. Any net gain is recorded account 254 - Other regulatory liabilities, and will be returned to customers.
2. PGE received approval for the sale of the Hawthorne building per OPUC Order 13-336. PGE vacated this building during 2013, retired from FERC 390 Structures and Improvements. The amount of $766,778 represents the remaining net plant reclassified to FERC 186 - Miscellaneous deferred debits, to offset any gain on sale. Any net gain is recorded account 254 - other regulatory liabilities, and will be returned to customers.
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 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 is estimated at $96 million and $2 million, respectively. It is 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 will be submitted to the FERC no later than June 30th, 2014, in compliance with the accounting under the Uniform System of Accounts. Following FERC approval, the proposed accounting entries will be executed which will increase both FERC Account 101, Electric plant in service, and FERC Account 108, Accumulated provision for depreciation, by an estimated $98 million, with corresponding offsets to Account 102, Electric plant purchased or sold.

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			14,738
9	Sub - TOTAL			24,738
10				
11	SunWay 1, LLC			
12	Paid in Capital	5/29/08		156,273
13	Equity in Earnings			-109,981
14	Sub - TOTAL			46,292
15				
16	SunWay 2, LLC			
17	Paid in Capital	9/16/08		1,276,014
18	Equity in Earnings			-216,035
19	Sub - TOTAL			1,059,979
20				
21	SunWay 3, LLC			
22	Paid in Capital	10/19/09		2,415,395
23	Equity in Earnings			-858
24	Sub - TOTAL			2,414,537
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	3,722,671

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 2013/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
335,351	-350,000	89		8
335,351	-350,000	10,089		9
				10
				11
	100,000	256,273		12
37,404		-72,577		13
37,404	100,000	183,696		14
				15
				16
		1,276,014		17
215,403		-632		18
215,403		1,275,382		19
				20
				21
		2,415,395		22
-10		-868		23
-10		2,414,527		24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
588,148	-250,000	4,060,819		42

Schedule Page: 224 Line No.: 14 Column: g

Represents PGE'S share of SunWay 1, LLC, a variable interest entity jointly owned by PGE (0.01% interest) and U.S. Bank (99.99% interest). SunWay 1, LLC was formed for the sole purpose of (1) Designing, developing, constructing, owning, maintaining, operating, and financing a photovoltaic solar power facility located at the intersection of I-5 North and I-205 South in Tualatin, Oregon, which is owned by the Oregon Department of Transportation, (2) Selling the energy generated by the facility, and (3) Licensing the site.

SunWay 1, LLC statistics at 12/31/2013 (100%)

In-Service Production cost: $1,097,814
Total installed capacity: 104 kW
Operations and Maintenance for 2013: $67,244

Schedule Page: 224 Line No.: 19 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.

SunWay 2, LLC statistics at 12/31/2013 (100%)

In-service Production cost: $5,922,280
Total installed capacity: 1.1 MW
Operations and Maintenance for 2013: $725,575

Schedule Page: 224 Line No.: 24 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.

SunWay 3, LLC statistics at 12/31/2013 (100%)

In-service Production cost: $7,454,015
Total installed cappacity: 2.4 MW
Operations and Maintenance for 2013: $479,292

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 2013/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)	39,663,607	24,019,002	Generation
2	Fuel Stock Expenses Undistributed (Account 152)		1,402,813	Generation
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	12,548,768	11,372,887	Distribution
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	18,899,066	19,477,615	Generation
8	Transmission Plant (Estimated)	208,875	215,900	Transmission
9	Distribution Plant (Estimated)	1,345,935	3,439,418	Distribution
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	165,157	277,648	Power Operations
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	33,167,801	34,783,468	
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)	4,817,251	4,765,622	
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	77,648,659	64,970,905	

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

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

Allowances (Accounts 158.1 and 158.2)

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

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2014 No. (d)	2014 Amt. (e)
1	Balance-Beginning of Year	29,864.00	252,288	10,033.00	
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	10,521.00	138,960		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	19,343.00	113,328	10,033.00	
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)		41		
45	Gains		41		
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 2013/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.

2015		2016		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
10,030.00		10,031.00		156,274.00		216,232.00	252,288	1
								2
								3
								4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						10,521.00	138,960	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
10,030.00		10,031.00		156,274.00		205,711.00	113,328	29
								30
								31
								32
								33
								34
								35
144.78		144.78		4,326.92		5,914.32		36
								37
								38
				144.78		289.56		39
144.78		144.78		4,182.14		5,624.76		40
								41
								42
								43
					6		47	44
					6		47	45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

Allowances (Accounts 158.1 and 158.2)

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

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year		2014	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

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

2015		2016		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
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								9
								10
								11
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								45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

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

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)]	Total Amount of Charges	Costs Recognised During Year	WRITTEN OFF DURING YEAR		Balance at End of Year
				Account Charged	Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
21						
22	Abandoned Trojan Nuclear Plant					
23	Decommissioning Costs;	307,024,282	2,787,003	407,254	6,189,789	
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 #07-0158, 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	307,024,282	2,787,003		6,189,789	

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

(1) $3,500,000 - Recovery of Trojan decommissioning costs, included in retail prices, until decommissioning is complete, as authorized by OPUC (Order #07-0158, dtd 1/12/2007), offset in account 407.

(2) $2,689,789 - Reclass balance of unrecovered plant and regulatory study costs related to Trojan to account 254, Regulatory liability. In 2013, $44 million was 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 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 2013/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	LGIP #09-03 FAC	2,000	561.7	2,000	456
23	LGIP #11-045 FAC	30,379	561.7	30,379	456
24	LGIP #11-046 FAC	31,360	561.7	31,360	456
25	LGIP #11-046 FAC Re-Study	19,169	561.7	19,169	456
26	LGIP #11-046 SIS Re-Study	19,347	561.7	19,347	456
27	LGIP #12-052 FEA	8,462	561.7	8,462	456
28	LGIP #12-053 FEA	8,417	561.7	8,417	456
29	Other	3,449	561.7		
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Schedule Page: 231   Line No.: 29   Column: b

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

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/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	50,563,007	1,120,736	282	4,127,351	47,556,392
2	Previously Flowed to Customers	33,708,671	747,157	283	2,751,567	31,704,261
3	(Amort. period is based on the lives of the					
4	properties, approximately 25 years.)					
5						
6	Photovoltaic Volumetric Incentive Pilot	62,403	4,961,390	407.3	5,000,882	22,911
7	(per OPUC Order No. 10-198 dtd 5/28/2010;					
8	amortization per Advice No. 11-30 dtd 12/2/2011;					
9	amortization period: 1/1/2012 - 12/31/2012)					
10	Reauthorized per Advice No.12-25 dtd 12/19/2012					
11	amortization period: 1/1/2013-12/31/2013					
12						
13	Colstrip Common Facilities (28 year amort. ending	1,395,947		407.3	322,140	1,073,807
14	2017, FERC OCA-AD ltr dtd 5/23/1989)					
15						
16	Price Risk Management	193,636,112	123,343,147	Various	140,701,430	176,277,829
17						
18	Deferred Broker Settlement	20,224,551	15,688,119	555	22,584,595	13,328,075
19						
20	Intervenor Funding (original deferral per OPUC	266,857	200,658			467,515
21	Order No. 03-388 dtd 7/2/2003; current year					
22	reauthorization through various orders; 2011					
23	amortization per Advice 10-22A dtd 12/23/2010)					
24						
25	Independent Evaluator Deferral	335,896	2,810	407.3	297,920	40,786
26	(per OPUC Order No. 08-010 dtd 1/14/2008)					
27	amortization per Advice No.12-19 dtd 12/18/2012					
28	amortization period: 1/1/2013-12/31/2013					
29						
30	Independent Evaluator Deferral (2011)	133,489	345,092			478,581
31	(per OPUC Order No. 11-154 dtd 5/10/2011)					
32						
33	Smart Meter Project Office Costs	43,708	41,771	407.3	85,479	
34	(per OPUC Order No. 08-209 dtd 4/11/2008;					
35	amortization per Advice No. 11-32 dated 12/12/2011;					
36	amortization period: 1/1/2012 - 12/31/2012)					
37						
38	Generation Plant Maintenance Deferral	4,106,952		557	684,492	3,422,460
39	(per OPUC Order no. 08-601 dtd 12/29/2008;					
40	amortization period: 1/1/2009 - 12/31/2018)					
41						
42	Stable Rate Revenue Balancing Acct	740,714	5,768	449.1	716,029	30,453
43	(per Advice No 06-13 dtd 6/22/2006)					
44	TOTAL	645,926,821	178,609,125		308,292,757	516,243,189

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 2013/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	amortization per Advice No.12-19 dtd 12/18/2012;					
2	amortization period: 1/1/2013-12/31/2013					
3						
4	Residential Sch 123 SNA Deferral-2011	209,310	801	449.1/456	210,111	
5	(reauthorized OPUC Order No. 11-110 dtd 4/7/2011)					
6	amortization per Advice No.12-07 dtd 5/22/2012;					
7	amortization period: 6/1/2012-5/31/2013					
8						
9	Residential Sch 123 SNA Deferral-2012	2,274,987	326,161	456	1,214,982	1,386,166
10	(reauthorized OPUC Order No. 12-061 dtd 2/28/2012)					
11	amortization per Advice No.13-06 dtd 5/31/2013;					
12	amortization period: 6/1/2013-5/31/2014					
13						
14	Residential Sch 123 SNA Deferral-2013		3,869,406	421	13,804	3,855,602
15	(reauthorized OPUC Order No.13-044 dtd 2/12/2013)					
16						
17	Trojan Refund Deferral - Incremental Costs	87,499	99,536	903/421	187,035	
18	(per OPUC Order No. 09-133 dtd 4/14/2009;					
19	amortization per Advice No. 11-35 dated 12/22/2011;					
20	amortization period: 1/1/2012 - 12/31/2012)					
21						
22	Residual Deferred Account	87,939		various	330,714	-242,775
23	(per OPUC Order No. 10-279 dtd 7/23/2010;					
24	amortization per Advice No. 11-32 dated 12/12/2011;					
25	amortization period: 1/1/2012 - 12/31/2012)					
26						
27	Glass Insulator Deferral	1,311,049	679,681	571	23,471	1,967,259
28	(per OPUC Order No. 10-478 dtd 12/17/2010;					
29	UE 215 First Revenue Requirement Stipulation)					
30						
31	Pension Funding	298,713,190		219/926	112,922,028	185,791,162
32	Postretirement Funding	21,875,784		219/926	13,776,142	8,099,642
33	(per SFAS No. 158 adopted 12/31/2006;					
34	OPUC Order No. 07-051 dtd 2/12/2007)					
35						
36	ISFSI Pollution Control Tax Credit Deferral	(5,099)	5,099			
37	(per OPUC Order No. 01-777 dtd 8/31/2001)					
38						
39	Boardman Decommissioning Balancing	365,089	4,279	456	116,363	253,005
40	(per Advice No. 11-07 dtd 05/27/2011)					
41						
42	Biglow Canyon Phase 3 Deferral	(89,106)	147,698	456	58,592	
43	(per OPUC Order No. 10-391 dtd 10/11/2010;					
44	TOTAL	645,926,821	178,609,125		308,292,757	516,243,189

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 2013/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	amortization period: 1/1/2011 - 12/31/2012)					
2						
3	UE 215 Four Capital Projects Deferral-2012 Vintage	15,527,194	412,391	182.3	1,253,878	14,685,707
4	(per OPUC Order No. 10-478 dtd 12/17/2010,					
5	UE 215 Second Revenue Requirement Stipulation)					
6	Approved into amortization as part of UE 262					
7	(per OPUC Order No.13-459 dtd 12/09/2013)					
8	amortization period: 1/1/2014 - 12/31/2014					
9						
10	UE 215 Four Capital Projects Deferral-2013 Vintage		19,246,095			19,246,095
11	(per OPUC Order No. 10-478 dtd 12/17/2010,					
12	UE 215 Second Revenue Requirement Stipulation)					
13						
14	Baldock Revenue Requirement Deferral	350,678	16,088	456	358,847	7,919
15	(per OPUC Order No. 12-063 dtd 2/28/2012)					
16	Amortization per Docket No.UE 249					
17	OPUC Advice No.12-09 dtd 12/18/2012					
18	Amortization period 01/01/2013-12/31/2013					
19						
20	Environmental Remediation Deferral		3,100,000			3,100,000
21						
22	Automated Demand Response Cost Recovery Mechanism		175,408			175,408
23	(per OPUC order No 13-059 dtd 2/26/2013					
24	Amortization per Advice No 13-04 dtd 3/8/2013					
25	Amortization period 01/01/2014-12/31/2014					
26						
27	2012 Lost Revenue Recovery Adjustment (LRRA)		858,519	242/256	554,905	303,614
28	(reauthorized OPUC Order No.12-061 dtde 2/28/2012;)					
29	amortization per Advice No.13-06 dtd 5/31/2013					
30	amortization period 6/1/2013-5/31/2014					
31						
32	2013 Lost Revenue Recovery Adjustment (LRRA)		2,586,359			2,586,359
33	(reauthorized OPUC Order No.13-044 dtd 2/12/2013)					
34						
35	Direct Access Open Enrollment Deferral -2013		624,956			624,956
36	(per OPUC Docket UE 246					
37	Advice No.12-09 dtd 12/18/2012)					
38						
39						
40						
41						
42						
43						
44	TOTAL	645,926,821	178,609,125		308,292,757	516,243,189

Schedule Page: 232 Line No.: 16 Column: d

Amounts charged to Accounts 555, 547, and 219.

Schedule Page: 232 Line No.: 20 Column: c

Current year reauthorization approved through OPUC Orders:
$66,125 Order No.13-002 dated 01/14/2013 from the CUB Fund. RE: Docket No.UM 1357(41)
$17,216 Order No.13-033 dated 02/11/2013 from the Matching Fund. RE: Docket No. UM 1357(42)
$6,652 Order No.13-036 dated 02/11/2013 from the Issue Fund. RE: Docket No. UM 1568
$14,463 Order No.13-034 dated 02/11/2013 from the Issue Fund. RE: Docket No. UM 1587
$9,058 Order No.13-312 dated 09/03/2013 from the CUB Fund. RE: Docket No.UM 1357(41)
$2,356 Order No.13-313 dated 09/03/2013 from the CUB Fund. RE: Docket No.UM 1357(41)
$18,020 Order No.13-366 dated 10/14/2013 RE: Docket No.UE 266
$49,179 Order No.13-367 dated 10/14/2013 RE: Docket No.UE 262
$6,996 Order No.13-414 dated 11/04/2013 RE: Docket No. UM 1616
$5,312 Order No.13-413 dated 11/04/2013 RE: Docket No. UM 1633

$5,281 in interest was recorded to account 421.

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

The residual credit balance of $41,771, remaining after the authorized amortization period, was transferred to the Residual Deferred Account, pursuant to OPUC Order No. 10-279 dated July 23, 2010.

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

The residual credit balance of $99,536, remaining after the authorized amortization period, was transferred to the Residual Deferred Account, pursuant to OPUC Order No. 10-279 dated July 23, 2010.

Schedule Page: 232.1 Line No.: 22 Column: d

Offset accounts 182.3, 254, 407.3, 421

Schedule Page: 232.1 Line No.: 22 Column: e

Various residual debit and credit balances remaining after the authorized amortization period on Account 182.3 were transferred to the Residual Deferred Account, pursuant to OPUC Order No. 10-279 dated July 23, 2010.
It included the following transfers:

- Trojan Refund Deferral of $(99,536)
- Smart Meter Project Office Costs of $(41,771)
- Biglow Canyon Phase 3 deferral of $(147,698)
- Residential Sch.123 SNA Deferral-2012 of $39,234
- Sch.32 SNA Deferral-2011 of $(13,679)

In addition, debit and credit balances on Account 254 were transferred to the Residual Deferred Account and included the following transfers:

- Portland Energy Solutions (PES) of $17,250
- 2011 Direct Access Open Enrollment of $(23,829)

$(3,097) in interest was expensed to Account 421.

In addition, total amortization of $(57,588) was written off to Account 407.3.

Schedule Page: 232.1 Line No.: 39 Column: e

Balancing account to track the difference between actual collections from customers and the revenue requirement related to the increase in depreciation/amortization expense and decommissioning costs due to the planned Boardman plant closure changing from the year 2040 to the year 2020.

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

The residual credit balance of $147,698, remaining after the authorized amortization period, was transfered to the Residual Deferred Account pursuant to OPUC Order No. 10-279 dated July 23, 2010.

Schedule Page: 232.2 Line No.: 3 Column: e

The credit of 1,253,878 is a result of a reclass between "UE-215 Four Capital Projects Deferral-2012 Vintage" and "UE-215 Four Capital Project Deferral-2013 Vintage" at year-end. The reclass moved the balance from account 182.3 (Current Asset GL account 1823002) to account 182.3 (Long-Term Asset account 1823001). Final true-up entry was made in January 2014 and will be reflected on page 232 in Q1-2014.

Schedule Page: 232.2 Line No.: 20 Column: c

PGE recorded a $3.1 million reserve based on the estimated costs of future clean-up activities for a portion of the Willamette River known as the Downtown Reach. The costs of clean up activities are estimated by a feasibility study ordered by the Oregon Department of Environmental Quality. Based on the available evidence of previous rate recovery of incurred environmental remediation costs for PGE, the Company recorded the reserve, and included recovery of the regulatory asset in its 2015 General Rate Case filed with the OPUC in February 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 2013/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	133,220	494,148	Various	379,712	247,656
3						
4	Net Co-owner / Trust Contributi	566,739	111,556,785	Various	110,315,549	1,807,975
5						
6	Deferred Rent - WTC Tenant					
7	amort. through 2021	41,455	966,358	418	80,276	927,537
8						
9	Deferred Revolving Credit					
10	Agreement Fees					
11	amort. through 2018	2,569,527	430,638	431	618,606	2,381,559
12						
13	Dispatchable Generation					
14	various amort. periods from					
15	2005 and extending through 2023	8,111,890	817,789	903	1,106,313	7,823,366
16						
17	LID Receivable from WTC Tenants					
18	amort. over 20 yrs through 2029	101,817		418	5,989	95,828
19						
20	Colstrip - Lime Contract					
21	amort. over 4 yrs. 2011 - 2014	1,197,828	2,172	Various	600,000	600,000
22						
23	Utility Property Sales-					
24	Selling Expenses	1,200,000	2,373,010	230	1,200,000	2,373,010
25						
26						
27						
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34						
35						
36						
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44						
45						
46						
47	Misc. Work in Progress	248,138				294,238
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	14,170,614				16,551,169

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 2013/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	4,029,595	1,094,274
3	Regulatory Liabilities	20,217,265	16,086,599
4	Employee Benefits	162,721,343	123,234,494
5	Price Risk Management	79,937,501	76,241,972
6	Tax Credits & NOL's	55,294,605	50,888,594
7	Other	11,720,925	32,979,191
8	TOTAL Electric (Enter Total of lines 2 thru 7)	333,921,234	300,525,124
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)	5,613,748	4,481,514
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	339,534,982	305,006,638

Notes

Line 7 - Other

	Ending Bal 12/31/2012	Ending Bal 12/31/2013
Bad Debt Expense	$2,120,104	$2,346,104
Nuclear Decommissioning Trust	1,170,507	20,233,197
Renewable Energy Development	4,445,738	6,075,684
Miscellaneous	3,984,576	4,324,206
Total Line 7 - Other	$11,720,925	$32,979,191

Line 17 - Other NonUtility	Ending Bal 12/31/2012	Ending Bal 12/31/2013
Property Related	$5,134,281	$4,032,008
Software Costs	0	0
Miscellaneous	479,467	449,506
Total Line 17 - Other NonUtuility	$5,613,748	$4,481,514

Schedule Page: 234 Line No.: 1 Column:

CAPITAL STOCKS (Account 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Account 201:			
2	Common Stock	160,000,000		
3				
4	Total_Com	160,000,000		
5				
6	Account 204:			
7	No Par Value Cumulative Preferred	30,000,000		
8				
9	Total_pre	30,000,000		
10				
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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
78,085,559	905,787,872					2
						3
78,085,559	905,787,872					4
						5
						6
						7
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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 2013/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	1,102,665
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	8,317,515
21	SUBTOTAL Account 211	9,956,413
22		
23		
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27		
28		
29		
30		
31		
32		
33		
34		
35		
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39		
40	TOTAL	16,366,513

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

Represents the assumption of PGE's current 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 2013/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		
5		
6		
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8		
9		
10		
11		
12		
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18		
19		
20		
21		
22	TOTAL	10,832,643

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	/ /	2013/Q4

FOOTNOTE DATA

Schedule Page: 254   Line No.: 1   Column: b

$3,056,495 million increase in Capital Stock Expense is due to stock issuance fees related to an Equity Forward Sale Agreement. For further information, see Note 12 - Equity-Based Plans, in the Notes to Financial Statements, p.122-123.

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 2013/Q4

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACCOUNT 221 - Bonds:		
2	First Mortgage Bonds -		
3	9.31% Medium-Term Note Series Due 8/11/2021	20,000,000	176,577
4	5.625% Series VI Due 8/1/2013	50,000,000	406,662
5			325,000 D
6	6.75% Series VI Due 8/1/2023	50,000,000	519,234
7			437,500 D
8	6.875% Series VI Due 8/1/2033	50,000,000	519,257
9			437,500 D
10	6.26% Series Due 5/1/2031	100,000,000	723,856
11	6.31% Series Due 5/1/2036	175,000,000	1,270,565
12	5.80% Series Due 6/1/2039	170,000,000	1,460,968
13	5.81% Series Due 10/1/2037	130,000,000	1,109,574
14			517,518 D
15	5.80% Series Due 03/01/2018	75,000,000	282,501
16	4.45% Series Due 04/1/2013	50,000,000	340,444
17			625,100 D
18			
19	6.80% Series Due 1/15/2016 - Order No. 08-106 01/28/2008	67,000,000	456,731
20	6.10% Series Due 4/15/2019 - Order No. 09-089 03/16/2009	300,000,000	2,386,224
21			222,000 D
22	5.43% Series Due 5/3/2040 - Order No. 09-245 06/22/2009	150,000,000	1,034,284
23	3.46% Series Due 1/14/2015 - Order No. 09-405 10/08/2009	70,000,000	455,869
24	3.81% Series Due 6/15/2017 - Order No. 09-405 10/08/2009	58,000,000	375,096
25	4.47% Series Due 6/15/2044 - Order No. 13-098 03/26/2013	150,000,000	1,113,047
26	4.47% Series Due 8/14/2043 - Order No. 13-098 03/26/2013	75,000,000	558,740
27	4.84% Series Due 12/15/2048 - Order No. 13-098 03/26/2013	50,000,000	652,029
28	4.74% Series Due 11/15/2042 - Order No. 13-098 03/26/2013	105,000,000	311,154
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	2,016,501,817	19,937,049

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 2013/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	2,016,400,000	19,937,049
3			
4	ACCOUNT 224 - OTHER LONG TERM DEBT		
5			
6	City of Portland Improvement District Loan	101,817	
7	SUBTOTAL ACCOUNT 224	101,817	
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29			
30			
31			
32			
33	TOTAL	2,016,501,817	19,937,049

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
08/12/1991	08/11/2021	08/12/1991	08/11/2021	20,000,000	1,862,000	3
08/01/2003	08/01/2013	08/01/2003	08/01/2013		1,640,625	4
						5
08/01/2003	08/01/2023	08/01/2003	08/01/2023	50,000,000	3,375,000	6
						7
08/01/2003	08/01/2033	08/01/2003	08/01/2033	50,000,000	3,437,500	8
						9
05/26/2006	05/01/2031	05/26/2006	05/01/2031	100,000,000	6,260,000	10
05/26/2006	05/01/2036	05/26/2006	05/01/2036	175,000,000	11,042,500	11
05/16/2007	06/01/2039	05/16/2007	06/01/2039	170,000,000	9,860,000	12
09/19/2007	10/01/2037	09/19/2007	10/01/2037	130,000,000	7,553,000	13
						14
12/12/2007	03/01/2018	12/12/2007	03/01/2018	75,000,000	4,350,000	15
04/15/2008	04/01/2013	04/15/2008	04/01/2013		556,250	16
						17
						18
01/15/2009	01/15/2016	01/15/2009	01/15/2016	67,000,000	4,556,000	19
04/16/2009	04/15/2019	04/16/2009	04/15/2019	300,000,000	18,300,000	20
						21
11/30/2009	05/03/2040	11/30/2009	05/03/2040	150,000,000	8,145,000	22
01/15/2010	01/14/2015	01/15/2010	01/14/2015	70,000,000	2,422,000	23
06/15/2010	06/15/2017	06/15/2010	06/15/2017	58,000,000	2,209,800	24
6/27/2013	6/15/2044	6/27/2013	6/15/2044	150,000,000	3,427,000	25
8/29/2013	8/14/2043	8/29/2013	8/14/2043	75,000,000	1,136,125	26
12/16/2013	12/15/2048	12/16/2013	12/15/2048	50,000,000	100,833	27
11/15/2013	11/15/2042	11/15/2013	11/15/2042	105,000,000	635,950	28
						29
						30
05/28/1998	05/01/2033	05/28/1998	05/01/2033	23,600,000	4,890,000	31
05/28/1998	05/01/2033	05/28/1998	05/01/2033	97,800,000	1,180,000	32
				1,916,495,828	96,939,583	33

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
				1,916,400,000	96,939,583	2
						3
						4
						5
11/16/2009	11/16/2029			95,828		6
				95,828		7
						8
						9
						10
						11
						12
						13
						14
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						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				1,916,495,828	96,939,583	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 2013/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)	104,591,295
2		
3		
4	Taxable Income Not Reported on Books	
5	Depreciation, Depletion, & Amortization	19,776,243
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Depreciation, Depletion, & Amortization	
11	Regulatory Debits	24,019,103
12	Other (See Footnote)	92,906,321
13		
14	Income Recorded on Books Not Included in Return	
15	Price Risk Management and Mark-to-Market	-17,358,283
16	Depreciation, Depletion & Amortization	-19,646,743
17	Regulatory Credits	-6,626,881
18	Other (See Footnote)	-5,450,115
19	Deductions on Return Not Charged Against Book Income	
20	Depreciation, Depletion & Amortization	-60,888,227
21	State & Local Tax Deduction	-302,275
22	Other (See Footnote)	-8,623,193
23		
24		
25		
26		
27	Federal Tax Net Income	122,397,246
28	Show Computation of Tax:	
29	Normal Federal Current Provision Benefit @ 35%	42,839,036
30	Federal Energy Tax Credit	-32,157,255
31	RTA Adjustment	-1,101,340
32	Total Federal Income Tax - PGE	9,580,441
33		
34		
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44		

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

Qualified NDT	$ 47,657,084
Meals & Entertainment	607,692
Political Activity	800,736
Bad Debts	565,000
Employee Benefits	6,252,505
Federal Tax Expense	13,638,803
Unamortized loss on reacquired debt	5,178,592
Environmental Remediation	3,100,000
Renewable Energy Initiatives	4,074,865
State Tax Expense	7,283,968
Miscellaneous	3,747,076
Total Other	$ 92,906,321

Schedule Page: 261 Line No.: 18 Column: b

Stock Incentive Plans	(2,219,473)
Key Man Insurance	(2,810,998)
Miscellaneous	(419,644)
Total Other	($ 5,450,115)

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

Dividend Received Deduction	($ 65,000)
IRC Sec 199 Domestic Production Activities Deduction	(3,489,529)
Property Tax	(2,244,436)
Project Reserve	(1,500,000)
Miscellaneous	(1,324,228)
Total Other	($ 8,623,193)

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 2013/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		511,275	511,275	
3	Income Tax	2,231,095	3,844,810	9,580,443	9,000,000	187,467
4	Foreign Insurance Excise Tax					
5	FICA (Employer Share)	1,364,365		16,603,731	16,593,004	
6	Unemployment	8,942		113,549	120,000	
7	Power License	668,111	1	1,676,835	1,708,080	
8	Superfund Tax					
9	SUBTOTAL Federal	4,397,514	3,844,811	28,485,833	27,932,359	187,467
10	State of Montana:					
11	Income Tax	139,740	108,654	37,004	107,785	
12	Elec. Energy Producers Tax	212,297		632,171	657,268	
13	Property Taxes	2,554,507		5,193,501	5,169,110	
14	SUBTOTAL Montana	2,906,544	108,654	5,862,676	5,934,163	
15	State of Oregon:					
16	Corp Excise Tax	4,973,202	5,283,533	-547,493	-300,000	38,637
17	Property Taxes	434,995	21,502,056	44,218,232	46,565,763	
18	City Taxes and Licenses	3,475,812		41,184,583	41,273,845	
19	Public Utility Comm Fees			4,557,928	4,557,928	
20	Department of Energy		600,256	1,287,143	1,373,770	
21	Department of Enviro Quality	372,515		426,734	353,054	
22	Unemployment	49,250		2,225,761	2,201,651	
23	Water Power Fee		-166,853	-151,256	567,794	
24	Transportation Tax	325,366		1,335,386	1,328,830	
25	Workers Comp Assessment	49,329		240,888	232,453	
26	County & City Income Tax	779,002	704,771	538,916	560,000	19,261
27	SUBTOTAL Oregon	10,459,471	27,923,763	95,316,822	98,715,088	57,898
28	State of Washington:					
29	Property Taxes	36,000		41,616	39,132	
30	Sales Tax			1,380,971	1,380,971	
31	SUBTOTAL Washington	36,000		1,422,587	1,420,103	
32	State of Wyoming:					
33	Sales Tax					
34	SUBTOTAL Wyoming					
35	State of California:					
36	Corporate franchise tax				400,000	
37	SUBTOTAL California				400,000	
38	Canada:					
39	Goods & Services Tax					
40	SUBTOTAL Canada					
41	TOTAL	17,799,529	31,877,228	131,087,918	134,401,713	245,365

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 2013/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					511,275	2
	845,805	27,599,530			-18,019,087	3
		9,600			-9,600	4
1,375,092		10,456,713			6,147,018	5
2,491		66,053			47,496	6
636,866					1,676,835	7
						8
2,139,450	845,805	38,131,896			-9,646,063	9
						10
	39,695	166,575			-129,571	11
187,200		370,993			261,178	12
2,578,897		4,150,571			1,042,930	13
2,766,097	39,695	4,688,139			1,174,537	14
						15
	519,186	3,280,145			-3,827,638	16
	23,414,592	42,575,617			1,642,615	17
3,386,550		41,184,583				18
					4,557,928	19
	686,883	1,287,143				20
446,195					426,734	21
73,360		1,294,757			931,004	22
	552,197				-151,256	23
331,922		776,813			558,573	24
57,764		144,197			96,691	25
	-72,407	859,399			-320,483	26
4,295,791	25,100,451	91,402,654			3,914,168	27
						28
38,484		41,616				29
					1,380,971	30
38,484		41,616			1,380,971	31
						32
						33
						34
						35
	400,000					36
	400,000					37
						38
						39
						40
9,239,822	26,385,951	134,264,305			-3,176,387	41

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) _ A Resubmission	/ /	2013/Q4

FOOTNOTE DATA

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

Tax Payment from Subsidiary	$ 164,413
Federal Tax Return Interest	23,054
Total Adjustments	$ 187,467

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

Tax Payment from Subsidiary

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

Tax Payment from Subsidiary

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/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							
15							
16							
17							
18							
19							
20							
21							
22							
23							
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42							
43							
44							
45							
46							
47							
48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

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

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
			15
			16
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			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
			34
			35
			36
			37
			38
			39
			40
			41
			42
			43
			44
			45
			46
			47
			48

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	49,672	418	5,270		44,402
7						
8	Deferred Liability for Transferred	795,883	421	52,768		743,115
9	Non-Qualified Plan Benefits					
10						
11	Carty Retainage for EPC Contract				6,370,515	6,370,515
12						
13	Environmental Remediation Deferral				3,100,000	3,100,000
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	1,596,555		58,038	9,470,515	11,009,032

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

Retainage withheld from payments to contractors building the Carty Generating Station (retained in accordance with contractual agreements)

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

PGE recorded a $3.1 million reserve based on the estimated costs of future clean-up activities for a portion of the Willamette River known as the Downtown Reach. The costs of clean up activities are estimated by a feasibility study ordered by the Oregon Department of Environmental Quality. Based on the available evidence of previous rate recovery of incurred environmental remediation costs for PGE, the Company recorded the reserve, and included recovery of the regulatory asset in its 2015 General Rate Case filed with the OPUC in February 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 2013/Q4

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

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

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

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				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
							2
							3
							4
							5
							6
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							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/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	597,926,639	73,552,515	49,407,247
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	597,926,639	73,552,515	49,407,247
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	597,926,639	73,552,515	49,407,247
10	Classification of TOTAL			
11	Federal Income Tax	490,643,201	48,946,837	30,701,753
12	State Income Tax	99,507,420	23,310,306	18,029,593
13	Local Income Tax	7,776,018	1,295,372	675,901

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
		182.3	13,782,397	254	10,775,782	619,065,292	2
							3
							4
			13,782,397		10,775,782	619,065,292	5
							6
							7
							8
			13,782,397		10,775,782	619,065,292	9
							10
			11,177,420		8,855,148	506,566,013	11
			2,428,076		1,779,742	104,139,799	12
			176,902		140,893	8,359,480	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 2013/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Property Related	33,711,198		
4	Price Risk Management	2,483,056	3,655,775	407,992
5	Regulatory Assets	224,160,487	42,982,208	92,726,222
6	Regulatory Liabilities			
7	Other	17,030,719	1,315,279	2,555,699
8				
9	TOTAL Electric (Total of lines 3 thru 8)	277,385,460	47,953,262	95,689,913
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other	1,292,526		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	278,677,986	47,953,262	95,689,913
20	Classification of TOTAL			
21	Federal Income Tax	225,086,055	38,731,482	77,288,008
22	State Income Tax	49,576,863	8,530,888	17,023,240
23	Local Income Tax	4,015,068	690,893	1,378,664

NOTES

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

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

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
		254	9,094,181	182.3	7,088,725	31,705,742	3
						5,730,839	4
						174,416,473	5
							6
		219	60,945			15,729,354	7
							8
			9,155,126		7,088,725	227,582,408	9
							10
							11
							12
							13
							14
							15
							16
							17
1,699,080	143,463	236	914	236	1,961	2,849,190	18
1,699,080	143,463		9,156,040		7,090,686	230,431,598	19
							20
1,372,150	115,759		7,568,115		5,899,943	186,117,748	21
302,342	25,625		1,470,022		1,102,594	40,993,800	22
24,588	2,078		117,903		88,145	3,320,049	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	28,160,355	55,931,456
Price Risk Mgmt Deferral	49,294,090	14,579,675
ASC 715 Pension & Post Retirement	128,235,589	77,556,321
Regulatory Deferral Earn Test Offset	6,037,609	12,989,164
Miscellaneous	12,432,844	13,359,857
Total Other	$224,160,487	$174,416,473

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

	Balance at Beginning of Year	Balance at End of Year
Unamortized Loss on Reacquired Debt	$ 8,783,234	$ 6,711,798
Prepaid Property Tax	7,765,290	$ 9,077,739
Other	482,195	(60,183)
Total Other	$ 17,030,719	$ 15,729,354

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

	Balance at Beginning of Year	Balance at End of Year
Trust-Owned Life Insurance Gain/Loss	$ 895,494	$ 1,977,911
Other	397,032	871,278
Total Other	$ 1,292,526	$ 2,849,189

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 2013/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Excess Deferred Taxes	3,747,414	190	241,722		3,505,692
2						
3	Surplus CAA Allowances	672,847			69	672,916
4	(per OPUC Order No. 552 dtd 3/31/1993)					
5						
6	BPA Subscription Power - Balancing Account	8,269,346	456	57,734,060	56,077,948	6,613,234
7	(per OPUC Order No. 08-175 dtd 3/20/2008)	1,112,846	456	799,395	47,583	361,034
8						
9	Gain on Asset Sales	1,323,727	186	5,391	3,120,206	4,438,542
10	(per OPUC Order No. 01-777 dtd 8/31/2001)					
11						
12	Gain on TRC Sales	1,891,730			26,272	1,918,002
13	(per OPUC Order No. 07-083 dtd 3/5/2007)					
14						
15	Asset Retirement Obligations:	39,395,209	407.3	1,419,832	960,377	38,935,754
16	Balancing Account					
17						
18	Coyote Springs Major Maintenance Deferral	2,087,550	407.4/553	1,716,708	2,044,272	2,415,114
19	(per OPUC Order No. 01-777 dtd 8/31/2001;					
20	reauthorization OPUC Order No. 10-478					
21	dtd 12/17/2010)					
22						
23	ISFSI Pollution Control Tax Credit Deferral	8,489,887			77,908	8,567,795
24	(per OPUC Order No. 05-136 dtd 3/15/2005)					
25	amortization per Advice 10-22A dtd 12/28/2010;					
26	amortization period: 01/01/2011 - 12/31/2011)					
27						
28	Zero Interest Program Loan Repayments	1,297,748			272,104	1,569,852
29	(per Advice No. 05-19 dtd 12/20/2005)					
30						
31	Schedule 110 Energy Efficiency - Balancing Accout	897,801	131	850,000	134,233	182,034
32	(per Advice No. 07-25 dtd 5/20/2008)					
33						
34	Direct Access Open Enrollment - 2011	89,997	447/182.3	90,093	96	
35	(per Advice 10-23 dtd 11/15/2010;					
36	amortization per Advice 11-32 dtd 12/12/2011;					
37	amortization period: 01/01/2012-12/31/2012)					
38						
39	Direct Access Open Enrollment - 2012	493,801	447	471,474	3,885	26,212
40	(per Advice 11-31 dtd 11/15/2011)					
41	TOTAL	73,382,141		66,434,979	104,496,431	111,443,593

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 2013/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	amortization per Advice 12-19 dtd 12/18/2012;					
2	amortization period: 01/01/2013-12/31/2013)					
3						
4	Sunway 3 Investment Deferral	795,790	407.4	45,480		750,310
5	(per UM 1480 dtd 4/01/2010;					
6	amortization over 20 years)					
7						
8	Baldock Solar - Gain on Sale	1,904,345	449.1	2,149,646	248,105	2,804
9	(per OPUC Order No. 12-063 dtd 2/28/2012)					
10	amortization per Advice 12-09 dtd 12/18/2012;					
11	amortization period: 01/01/2013-12/31/2013)					
12						
13	Multnomah County Business Income Tax Balancing	912,731	407.4	894,556	4,394	22,569
14	(per Advice No. 11-27 dtd 10/27/2012;					
15	Schedule 6; OAR 860-022-0045)					
16						
17	Interest on Portland Energy Solutions Note	(628)	407.4	16,622	17,250	
18	(per OPUC Order No. 02-280 dtd 4/19/2002)					
19	amortization per Advice 11-32 dtd 12/12/2011;					
20	amortization period: 01/01/2012-12/31/2012)					
21						
22	Trojan Decommissioning Deferral				41,461,729	41,461,729
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	73,382,141		66,434,979	104,496,431	111,443,593

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

Reclassed the Bull Run land retirement to account 254 due to the sale to Western Rivers in February 2013.

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

Sale of utility property including $2,081,228 for sale of buildings and land in Southeast Portland to Tri-Met for the construction of its light rail project (OPUC Order No.13-006 dated 01.15.2013); $621,129 for sale of Bull Run property(OPUC Order No.11-424 dated 10.26.2011, Docket No. UP 274); $251,087 for sale of Alder Substation (OPUC Order No.13-022 dated 01.29.2013, Docket No. UP 283); other small right of way easements of $113,182. Also added accrued interest of $53,580.

Schedule Page: 278 Line No.: 31 Column: d

Transferred excess $850,000 to Energy Trust of Oregon per OPUC Advice No.12-22, dated 11.16.2012.

Schedule Page: 278 Line No.: 34 Column: d

Total $90,093 consists of $66,264 in residual amortization from 2012 to account 447, and residual balance of $23,829 remaining after the authorized amortization period, 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.: 8 Column: e

Total amount of $248,105 consists of $16,027 in accrued interest, and $232,078 of reclass from FERC account 102 per FERC approval on Docket AC12-135-000, dated 04.04.2013.

Schedule Page: 278.1 Line No.: 17 Column: d

This amount represents remaining amortization from December 2012 billing cycle.

Schedule Page: 278.1 Line No.: 17 Column: e

Residual balance of $17,250, 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.: 22 Column: e

Settlement amount of $44,151,519 received in September 2013 from the US Government for Trojan Spent Fuel settlement (The United States Court of Federal Claims, Case No. 04-009C), net of $2,689,790 deferred expenses reclassed out of account 182.2

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 2013/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	805,593,907	804,944,928
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	592,028,129	608,842,827
5	Large (or Ind.) (See Instr. 4)	206,820,494	225,347,823
6	(444) Public Street and Highway Lighting	17,532,792	17,956,680
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,621,975,322	1,657,092,258
11	(447) Sales for Resale	119,051,973	72,173,577
12	TOTAL Sales of Electricity	1,741,027,295	1,729,265,835
13	(Less) (449.1) Provision for Rate Refunds	-3,676,424	-7,763,527
14	TOTAL Revenues Net of Prov. for Refunds	1,744,703,719	1,737,029,362
15	Other Operating Revenues		
16	(450) Forfeited Discounts	2,758,129	2,587,422
17	(451) Miscellaneous Service Revenues	1,855,439	2,303,654
18	(453) Sales of Water and Water Power	14,457	4,641
19	(454) Rent from Electric Property	6,875,612	7,406,637
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	81,520,491	66,586,129
22	(456.1) Revenues from Transmission of Electricity of Others	7,689,044	7,253,320
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	100,713,172	86,141,803
27	TOTAL Electric Operating Revenues	1,845,416,891	1,823,171,165

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 2013/Q4

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
7,701,768	7,505,405	728,481	723,440	2
				3
6,787,898	6,853,728	104,131	103,520	4
3,075,442	3,474,566	263	261	5
108,339	110,736	254	246	6
				7
				8
				9
17,673,447	17,944,435	833,129	827,467	10
3,553,416	3,188,338	41	43	11
21,226,863	21,132,773	833,170	827,510	12
				13
21,226,863	21,132,773	833,170	827,510	14

Line 12, column (b) includes $ -5,809,000 of unbilled revenues.
Line 12, column (d) includes -57,746 MWH relating to unbilled revenues

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Portland General Electric Company	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) / /	2013/Q4

FOOTNOTE DATA

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

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.: 4 Column: c

Includes $16,503,790 in revenue related to the delivery of 438,470 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 2012, 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 $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.: 5 Column: c

Includes $16,771,151 in revenue related to the delivery of 808,238 megawatt hours to customers of Energy Services Suppliers (ESSs). For 2012, 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

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 Payment Charges
Reconnect Charges
Field Service Charges
Meter Tamper Charges

Meter Test Charges
Meter Verification Charges
Switching Fees

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

Other Electric Revenues consist of the following:

	2013	2012
BPA Subscription Power - Balancing Account	$ 58,533,455	$ 59,608,867
Biglow Canyon Phase 2 Deferral	-	(25,662)
Biglow Canyon Phase 3 Deferral	(58,371)	(900,395)
Residential Sch 123 SNA Deferral	2,739,997	(862,556)
Small Nonresidential Sch 123 SNA Deferral	-	(1,235,988)
Sch 123 LRRA Deferral	3,238,746	-
Baldock Solar	1,790,798	$350,678
Boardman Decomissioning Balancing Account	(716,005)	(451,573)
EE Program Delivery Contractor Services	1,881,563	1,725,828
PGE Share of Boardman Ash Sales	291,669	322,790
Large Generator Interconnection Process	265,009	-
Park Revenues	530,566	526,923
Steam Sales	2,004,226	1,553,085
Gas for Resale	3,574,536	-
Oil for Resale	2,502,608	-
Wheeling Resale	4,508,627	5,296,820
Other - net	433,067	677,310
Totals	$ 81,520,491	$ 66,586,129

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 2013/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					
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9					
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12					
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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 2013/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	7,632,214	798,365,078	727,985	10,484	0.1046
3	12 Critical Peak Pricing Pilot	5,137	528,139	496	10,357	0.1028
4	15 Outdoor Area Lighting	6,841	1,494,690			0.2185
5	Residential Unbilled Revenue	57,577	5,206,000			0.0904
6	TOTAL Account 440	7,701,769	805,593,907	728,481	10,572	0.1046
7						
8	General Comm. and Ind. Sales:					
9	15 Comm. Outdoor Lighting	15,939	2,687,563			0.1686
10	32 Small Nonresidential	1,552,170	154,833,952	87,888	17,661	0.0998
11	38 Optional Time of Day -	30,759	3,657,027	289	106,433	0.1189
12	Large Nonresidential					
13	47 Irrigation - Drainage - Small	18,704	2,435,188	2,031	9,209	0.1302
14	49 Irrigation - Drainage - Large	59,039	5,299,909	1,053	56,067	0.0898
15	83-S Large Nonresidential	2,732,366	226,445,115	11,141	245,253	0.0829
16	85-S Large Nonresidential	1,933,631	147,682,021	1,194	1,619,456	0.0764
17	89-S Large Nonresidential	424,444	30,838,453	70	6,063,486	0.0727
18	485-S COS Opt-Out - Lrg. Nonresid		9,958,918	147		
19	485-S COS Opt-Out - Lrg. Nonresid	1,097	68,464	1	1,097,000	0.0624
20	489-S COS Opt-Out - Lrg. Nonresid		1,610,250	7		
21	489-S COS Opt-Out - Lrg. Nonresid	7,496	366,276	1	7,496,000	0.0489
22	515-S DAS - Outdoor Area Lighting		7,978			
23	532-S DAS - Small Nonresidential		245,001	98		
24	583-S DAS - Large Nonresidential		2,747,111	172		
25	585-S DAS - Large Nonresidential		2,324,657	36		
26	589-S DAS - Large Nonresidential		430,246	2		
27	Gen Comm. & Ind. Unbilled Revenue	12,253	390,000			0.0318
28	TOTAL Account 442 - Small	6,787,898	592,028,129	104,130	65,187	0.0872
29						
30	Large Industrial Power Sales:					
31	75 Partial Requirements Service	647,145	27,356,242	1	647,145,000	0.0423
32	85-P Large Nonresidential	212,060	15,506,793	120	1,767,167	0.0731
33	89-T Large Nonresidential	103,789	6,824,089	4	25,947,250	0.0657
34	89-P Large Nonresidential	2,124,057	134,283,019	81	26,222,926	0.0632
35	485-P COS Opt-Out - Lg. Nonreside		3,214,160	26		
36	489-T COS Opt-Out - Lg. Nonreside		5,064,896	3		
37	489-P COS Opt-Out - Lg. Nonreside		13,339,802	20		
38	583-P DAS - Large Nonresidential					
39	585-P DAS - Large Nonresidential		428,974	7		
40	589-P DAS - Large Nonresidential		522,519	1		
41	TOTAL Billed	17,615,701	1,616,166,322	833,129	21,144	0.0917
42	Total Unbilled Rev.(See Instr. 6)	57,746	5,809,000	0	0	0.1006
43	TOTAL	17,673,447	1,621,975,322	833,129	21,213	0.0918

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 2013/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	Large Industrial Unbilled Revenue	-11,610	280,000			-0.0241
2	TOTAL Account 442 - Large	3,075,441	206,820,494	263	11,693,692	0.0672
3						
4	Various Public Street and					
5	Highway Lighting:					
6	Street Lighting	108,813	17,599,792	255	426,718	0.1617
7	Street Lighting Unbilled Rev	-474	-67,000			0.1414
8	TOTAL Account 444	108,339	17,532,792	255	424,859	0.1618
9						
10	Other Sales to Public Authorities					
11	Communication Devices Electr					
12	TOTAL Account 445					
13						
14						
15						
16						
17						
18						
19						
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21						
22						
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41	TOTAL Billed	17,615,701	1,616,166,322	833,129	21,144	0.0917
42	Total Unbilled Rev.(See Instr. 6)	57,746	5,809,000	0	0	0.1006
43	TOTAL	17,673,447	1,621,975,322	833,129	21,213	0.0918

Schedule Page: 304 Line No.: 15 Column: a
Rate Schedule 83 complete title: Large Nonresidential Standard Service (31 - 200 kW).

Schedule Page: 304 Line No.: 16 Column: a
Rate schedule 85 complete title: Large Nonresidential Standard Service (201 - 1,000 kW).

Schedule Page: 304 Line No.: 17 Column: a
Rate schedule 89 complete title: Large Nonresidential (>1,000 kW) Standard Service.

Schedule Page: 304 Line No.: 18 Column: a
Rate Schedule 485 complete title: Large Nonresidential (<1,000 kW) Cost of Service Opt-out.

Schedule Page: 304 Line No.: 18 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.: 19 Column: a
Rate Schedule 485 complete title: Large Nonresidential (<1,000 kW) Cost of Service Opt-out.

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. In 2013, this customer purchased its energy from PGE.

Schedule Page: 304 Line No.: 20 Column: a
Rate Schedule 489 complete title: Large Nonresidential (>1,000 kW) Cost of Service Opt-out.

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 489 complete title: Large Nonresidential (>1,000 kW) Cost of Service Opt-out.

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. In 2013, this customer purchased its energy from PGE.

Schedule Page: 304 Line No.: 22 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.: 23 Column: a
Rate Schedule 532 complete title: Small Nonresidential Direct Access Service.

Schedule Page: 304 Line No.: 23 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.: 24 Column: a
Rate Schedule 583 complete title: Large Nonresidential Direct Access Service (31 - 200 kW).

Schedule Page: 304 Line No.: 24 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.: 25 Column: a
Rate Schedule 585 complete title: Large Nonresidential Direct Access Service (201 - 1,000 kW).

Schedule Page: 304 Line No.: 25 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 589 complete title: Large Nonresidential (>1,000 kW) Direct Access Service.

Schedule Page: 304 Line No.: 26 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 85 complete title: Large Nonresidential Standard Service (201 - 1,000 kW).

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

Rate schedule 89 complete title: Large Nonresidential (>1,000 kW) Standard Service.

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

Rate schedule 89 complete title: Large Nonresidential (>1,000 kW) Standard Service.

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

Rate Schedule 485 complete title: Large Nonresidential (<1,000 kW) Cost of Service Opt-out.

Schedule Page: 304 Line No.: 35 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.: 36 Column: a

Rate Schedule 489 complete title: Large Nonresidential (>1,000 kW) Cost of Service Opt-out.

Schedule Page: 304 Line No.: 36 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.: 37 Column: a

Rate Schedule 489 complete title: Large Nonresidential (>1,000 kW) Cost of Service Opt-out.

Schedule Page: 304 Line No.: 37 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.: 38 Column: a

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

Schedule Page: 304 Line No.: 38 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.: 39 Column: a

Rate Schedule 585 complete title: Large Nonresidential Direct Access Service (201 - 1,000 kW).

Schedule Page: 304 Line No.: 39 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.: 40 Column: a

Rate Schedule 589 complete title: Large Nonresidential (>1,000 kW) Direct Access Service.

Schedule Page: 304 Line No.: 40 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 2013/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	Avista Corp	SF	WSPP-1	NA	NA	NA
7	Black Hills Power	SF	WSPP-1	NA	NA	NA
8	Bonneville Power Administration	SF	WSPP-1	NA	NA	NA
9	BP Energy Company	SF	PGE-11	NA	NA	NA
10	Burbank, City of	SF	WSPP-1	NA	NA	NA
11	California ISO	SF	CAISO	NA	NA	NA
12	Calpine Energy Services	SF	EEI	NA	NA	NA
13	Cargill Alliant LLC	SF	WSPP-1	NA	NA	NA
14	Chelan County, PUD No. 1, 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 2013/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	Citigroup Energy Inc.	SF	WSPP-1	NA	NA	NA
2	Clatskanie County PUD, Washington	SF	WSPP-1	NA	NA	NA
3	Constellation Energy Commodities	SF	EEI	NA	NA	NA
4	CP Energy Marketing	SF	WSPP-1	NA	NA	NA
5	EDF Trading NA	SF	WSPP-1	NA	NA	NA
6	Eugene Water & Electric Board	SF	WSPP-1	NA	NA	NA
7	Exelon	SF	WSPP-1	NA	NA	NA
8	Glendale, City of	SF	WSPP-1	NA	NA	NA
9	Grant County, PUD No. 2, Washington	SF	WSPP-1	NA	NA	NA
10	Iberdrola Renewables	SF	EEI	NA	NA	NA
11	Idaho Power Company	SF	WSPP-1	NA	NA	NA
12	J. Aron Company	SF	EEI	NA	NA	NA
13	JP Morgan Ventures	SF	WSPP-1	NA	NA	NA
14	Load Balance Energy	OS	OATT	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Los Angeles Depart of 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	SF	WSPP-1	NA	NA	NA
6	Nevada Power	SF	WSPP-1	NA	NA	NA
7	NextEra Energy Solutions Inc	SF	WSPP-1	NA	NA	NA
8	Noble Americas Gas & Power Corp	SF	EEI	NA	NA	NA
9	Northern California Power Agency	SF	WSPP-1	NA	NA	NA
10	NorthWestern Corporation	SF	WSPP-1	NA	NA	NA
11	Okanogan County PUD, Washington	SF	WSPP-1	NA	NA	NA
12	PacifiCorp	LU	PGE-11	NA	NA	NA
13	PacifiCorp	SF	EEI	NA	NA	NA
14	Powerex	SF	PGE-11	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	PPL Energy Plus	SF	EEI	NA	NA	NA
2	PUD No. 1 of Clark County	SF	WSPP-1	NA	NA	NA
3	Puget Sound Energy	SF	WSPP-1	NA	NA	NA
4	Rainbow Energy Marketing	SF	WSPP-1	NA	NA	NA
5	Redding, City of	SF	WSPP-1	NA	NA	NA
6	Sacramento Municipal Utility Distric	SF	WSPP-1	NA	NA	NA
7	Salt River Project	SF	WSPP-1	NA	NA	NA
8	San Diego Gas & Electric Company	SF	WSPP-1	NA	NA	NA
9	Seattle City Light	SF	WSPP-1	NA	NA	NA
10	Shell Energy NA	SF	WSPP-1	NA	NA	NA
11	Sierra Pacific	SF	WSPP-1	NA	NA	NA
12	Snohomish County PUD Washington	SF	WSPP-1	NA	NA	NA
13	Southern California Edison	SF	EEI	NA	NA	NA
14	Tacoma, City of	SF	WSPP-1	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 2013/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	The Energy Authority	SF	WSPP-1	NA	NA	NA
2	TransAlta Energy Marketing	SF	EEI	NA	NA	NA
3	TransCanada Power	SF	WSPP-1	NA	NA	NA
4	Turlock Irrigation District	SF	WSPP-1	NA	NA	NA
5	Tuscon Electric Power Company	SF	WSPP-1	NA	NA	NA
6	Vitol Inc.	SF	WSPP-1	NA	NA	NA
7	Western Area Power Authority	SF	WSPP-1	NA	NA	NA
8						
9	REC Sale Deferral			NA	NA	NA
10						
11	Direct Access Deferral - 2013			NA	NA	NA
12	Direct Access Amortization - 2012			NA	NA	NA
13	Direct Access Amortization - 2011			NA	NA	NA
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do 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	Portland General Electric Company	SF	OA96137	500	NA	NA
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,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
	740,091	-112,596		627,495	2
					3
					4
					5
5,704		142,086		142,086	6
1,208		47,545		47,545	7
27,362		768,398		768,398	8
443,295		14,166,326		14,166,326	9
3,623		128,632		128,632	10
816,592		26,434,223		26,434,223	11
201,421		4,397,122		4,397,122	12
31,036		774,021		774,021	13
185,850		6,961,863		6,961,863	14
0	740,091	-112,596	0	627,495	
3,575,620	3,043,783	116,559,472	-1,178,777	118,424,478	
3,575,620	**3,783,874**	**116,446,876**	**-1,178,777**	**119,051,973**	

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.
32,609		791,493		791,493	1
65		2,792		2,792	2
1,018		59,520		59,520	3
500		7,900		7,900	4
10,010		267,624		267,624	5
4,411		133,495		133,495	6
6,000		175,120		175,120	7
2,168		73,683		73,683	8
8,175		295,300		295,300	9
370,259		11,290,233		11,290,233	10
14,059		504,819		504,819	11
14,400		466,412		466,412	12
46,900		1,431,869		1,431,869	13
18,350			544,342	544,342	14
0	740,091	-112,596	0	627,495	
3,575,620	3,043,783	116,559,472	-1,178,777	118,424,478	
3,575,620	**3,783,874**	**116,446,876**	**-1,178,777**	**119,051,973**	

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.
206,994		12,166,674		12,166,674	1
33,884		980,766		980,766	2
4,741		151,971		151,971	3
45,069		1,337,757		1,337,757	4
593		17,374		17,374	5
796		23,404		23,404	6
178		13,436		13,436	7
12,829		363,791		363,791	8
1,544		58,239		58,239	9
17,369		579,899		579,899	10
290		9,240		9,240	11
17,024			104,208	104,208	12
77,054		2,622,970		2,622,970	13
115,851		3,208,341		3,208,341	14
0	740,091	-112,596	0	627,495	
3,575,620	3,043,783	116,559,472	-1,178,777	118,424,478	
3,575,620	**3,783,874**	**116,446,876**	**-1,178,777**	**119,051,973**	

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 2013/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.
15,192		469,640		469,640	1
8,355		299,678		299,678	2
43,400		1,433,399		1,433,399	3
3,621		112,161		112,161	4
34,605		973,277		973,277	5
57,854		1,712,986		1,712,986	6
1		8		8	7
467		2,475		2,475	8
8,284		251,581		251,581	9
34,648		984,818		984,818	10
5,699		346,659		346,659	11
3,060		118,325		118,325	12
192,964		7,542,030		7,542,030	13
1,791		48,470		48,470	14
0	740,091	-112,596	0	627,495	
3,575,620	3,043,783	116,559,472	-1,178,777	118,424,478	
3,575,620	**3,783,874**	**116,446,876**	**-1,178,777**	**119,051,973**	

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.
112,768		3,305,339		3,305,339	1
131,160		3,828,303		3,828,303	2
51,314		2,090,764		2,090,764	3
66,242		2,048,074		2,048,074	4
500		22,325		22,325	5
1,000		37,400		37,400	6
1,260		52,690		52,690	7
					8
			-2,965,335	-2,965,335	9
					10
			600,270	600,270	11
			471,474	471,474	12
			66,264	66,264	13
					14
0	740,091	-112,596	0	627,495	
3,575,620	3,043,783	116,559,472	-1,178,777	118,424,478	
3,575,620	**3,783,874**	**116,446,876**	**-1,178,777**	**119,051,973**	

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.
22,204	3,043,783	24,732		3,068,515	1
					2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
0	740,091	-112,596	0	627,495	
3,575,620	3,043,783	116,559,472	-1,178,777	118,424,478	
3,575,620	**3,783,874**	**116,446,876**	**-1,178,777**	**119,051,973**	

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: 310.1 Line No.: 14 Column: j

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

Schedule Page: 310.2 Line No.: 12 Column: j

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

Schedule Page: 310.4 Line No.: 9 Column: j

Defer revenues for Renewable Energy Credit sales until title transferred to buyer.

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

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

Schedule Page: 310.4 Line No.: 12 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: 310.4 Line No.: 13 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: 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 2013/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	2,155,656	1,922,573
5	(501) Fuel	72,917,094	62,410,785
6	(502) Steam Expenses	4,930,412	4,121,523
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses	5,651,322	5,415,041
11	(507) Rents	40,452	35,391
12	(509) Allowances	138,960	107,712
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	85,833,896	74,013,025
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	749,347	-363,930
16	(511) Maintenance of Structures	1,019,602	696,540
17	(512) Maintenance of Boiler Plant	6,737,423	5,579,242
18	(513) Maintenance of Electric Plant	12,056,252	12,149,870
19	(514) Maintenance of Miscellaneous Steam Plant	793,806	808,375
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	21,356,430	18,870,097
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	107,190,326	92,883,122
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	618,646	502,310
45	(536) Water for Power	545,040	542,055
46	(537) Hydraulic Expenses	4,659,071	4,054,309
47	(538) Electric Expenses	1,080,812	1,154,534
48	(539) Miscellaneous Hydraulic Power Generation Expenses	2,690,890	2,694,420
49	(540) Rents	543,556	210,586
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	10,138,015	9,158,214
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	665,534	845,924
54	(542) Maintenance of Structures	44,308	74,130
55	(543) Maintenance of Reservoirs, Dams, and Waterways	561,882	866,633
56	(544) Maintenance of Electric Plant	1,567,244	1,026,929
57	(545) Maintenance of Miscellaneous Hydraulic Plant	1,200,908	1,569,483
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	4,039,876	4,383,099
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	14,177,891	13,541,313

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Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	2,290,494	2,858,792
63	(547) Fuel	207,138,283	225,046,527
64	(548) Generation Expenses	4,773,297	3,936,873
65	(549) Miscellaneous Other Power Generation Expenses	5,603,666	5,648,558
66	(550) Rents	281,224	280,616
67	TOTAL Operation (Enter Total of lines 62 thru 66)	220,086,964	237,771,366
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	993,826	820,014
70	(552) Maintenance of Structures	481,179	95,243
71	(553) Maintenance of Generating and Electric Plant	35,663,407	29,889,954
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	309,386	337,607
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	37,447,798	31,142,818
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	257,534,762	268,914,184
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	441,802,271	393,220,591
77	(556) System Control and Load Dispatching	80,921	229,000
78	(557) Other Expenses	16,827,789	16,306,843
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	458,710,981	409,756,434
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	837,613,960	785,095,053
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	3,495,647	2,313,489
84			
85	(561.1) Load Dispatch-Reliability	13,328	3,088
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	562,399	622,776
87	(561.3) Load Dispatch-Transmission Service and Scheduling	826,988	832,891
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	792,363	142,448
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies	122,583	225,071
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	206,294	132,092
94	(563) Overhead Lines Expenses	199,023	187,553
95	(564) Underground Lines Expenses		371
96	(565) Transmission of Electricity by Others	74,555,702	68,731,405
97	(566) Miscellaneous Transmission Expenses	3,123,421	2,905,354
98	(567) Rents	2,309,687	2,528,352
99	TOTAL Operation (Enter Total of lines 83 thru 98)	86,207,435	78,624,890
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	42,407	198,046
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software	975,907	1,357,691
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	861,968	1,041,787
108	(571) Maintenance of Overhead Lines	475,971	319,616
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of lines 101 thru 110)	2,356,253	2,917,140
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	88,563,688	81,542,030

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 2013/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
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	20,616,178	9,227,369
135	(581) Load Dispatching	1,709,316	1,774,353
136	(582) Station Expenses	811,225	499,258
137	(583) Overhead Line Expenses	1,573,615	757,393
138	(584) Underground Line Expenses	2,463,074	1,806,597
139	(585) Street Lighting and Signal System Expenses	573,732	589,884
140	(586) Meter Expenses	2,992,777	1,709,967
141	(587) Customer Installations Expenses	3,033,787	2,088,869
142	(588) Miscellaneous Expenses	6,387,753	8,605,835
143	(589) Rents	1,622,187	1,523,052
144	TOTAL Operation (Enter Total of lines 134 thru 143)	41,783,644	28,582,577
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	33,250	27,199
147	(591) Maintenance of Structures	140,003	142,928
148	(592) Maintenance of Station Equipment	3,650,066	2,985,908
149	(593) Maintenance of Overhead Lines	29,788,653	31,150,559
150	(594) Maintenance of Underground Lines	3,932,768	3,856,091
151	(595) Maintenance of Line Transformers	210,877	314,156
152	(596) Maintenance of Street Lighting and Signal Systems	1,687,834	1,540,575
153	(597) Maintenance of Meters	359,299	267,226
154	(598) Maintenance of Miscellaneous Distribution Plant	4,830,616	15,614,391
155	TOTAL Maintenance (Total of lines 146 thru 154)	44,633,366	55,899,033
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	86,417,010	84,481,610
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision		
160	(902) Meter Reading Expenses	885,612	912,009
161	(903) Customer Records and Collection Expenses	36,570,856	39,708,101
162	(904) Uncollectible Accounts	6,305,647	6,697,534
163	(905) Miscellaneous Customer Accounts Expenses	5,061,959	4,726,472
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	48,824,074	52,044,116

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	11,336,359	9,949,139
169	(909) Informational and Instructional Expenses	1,951,378	2,258,174
170	(910) Miscellaneous Customer Service and Informational Expenses		
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	13,287,737	12,207,313
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	52,776,420	52,489,752
182	(921) Office Supplies and Expenses	16,402,647	15,112,960
183	(Less) (922) Administrative Expenses Transferred-Credit	10,151,576	10,504,733
184	(923) Outside Services Employed	8,498,581	7,759,595
185	(924) Property Insurance	4,501,427	4,714,939
186	(925) Injuries and Damages	4,909,107	4,840,725
187	(926) Employee Pensions and Benefits	59,857,913	55,491,574
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	7,498,336	7,705,328
190	(929) (Less) Duplicate Charges-Cr.	2,167,352	2,065,837
191	(930.1) General Advertising Expenses	616,151	725,504
192	(930.2) Miscellaneous General Expenses	8,723,902	8,061,993
193	(931) Rents	3,522,784	3,881,853
194	TOTAL Operation (Enter Total of lines 181 thru 193)	154,988,340	148,213,653
195	Maintenance		
196	(935) Maintenance of General Plant	2,730,426	3,070,908
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	157,718,766	151,284,561
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	1,232,425,235	1,166,654,683

Schedule Page: 320 Line No.: 136 Column: b

There is $3,843 recorded in account 582.1, Operation of Energy Storage Equipment, and it’s being reported in this line. The equipment associated with these operating costs is recorded in the plant account 363, Storage Battery Equipment - Distribution.

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 2013/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	Avista Corp. - AVWP (was WWP)	SF	WSPP-1	NA	NA	NA
2	Barclays Bank PLC - BARC	SF	WSPP-1	NA	NA	NA
3	Baldock Solar	LU	Baldock	NA	NA	NA
4	Bellevue Solar	LU	Bellevue	NA	NA	NA
5	Black Hills Power	SF	WSPP-1	NA	NA	NA
6	Bonneville Power Administration	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
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/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.

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

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/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.
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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	Glendale, City of	SF	WSPP-1	NA	NA	NA
2	Grant County, PUD No. 2, Washington	LU	Wanapum	NA	NA	NA
3	Grant County, PUD No. 2, Washington	LU	Priest Rapids	NA	NA	NA
4	Grant County, PUD No. 2, Washington	SF	WSPP-1	NA	NA	NA
5	Iberdrola Renewables	SF	PGE-11	NA	NA	NA
6	Iberdrola Renewables	LU	PGE-11	NA	NA	NA
7	Idaho Power Company	SF	WSPP-1	NA	NA	NA
8	J. Aron Company	SF	PGE-11	NA	NA	NA
9	JC Biomethane	LF	JCBIO	NA	NA	NA
10	JP Morgan Ventures	SF	WSPP-1	NA	NA	NA
11	Load Balance Energy	OS	OATT	NA	NA	NA
12	Los Angeles Depart Water Power	SF	WSPP-1	NA	NA	NA
13	Macquarie Cook Power	SF	WSPP-1	NA	NA	NA
14	Modesto Irrigation District	SF	WSPP-1	NA	NA	NA
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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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	Morgan Stanley Capital Group	SF	PGE-11	NA	NA	NA
2	Nevada Power Company	SF	WSPP-1	NA	NA	NA
3	NextEra Energy Power Marketing, LLC	SF	WSPP-1	NA	NA	NA
4	NextEra Energy Power Marketing, LLC	LF	WSPP-1	NA	NA	NA
5	Noble Americas Gas & Power	SF	WSPP-1	NA	NA	NA
6	Northern California Power Agency	SF	WSPP-1	NA	NA	NA
7	Northern Wasco PUD Hydro	LU	NWASCO	NA	NA	NA
8	NorthWestern Corporation	SF	WSPP-1	NA	NA	NA
9	Okanogan County PUD, Washington	SF	WSPP-1	NA	NA	NA
10	Outback Solar	LU	Outback	NA	NA	NA
11	PacifiCorp	RQ	PP&L 147	NA	NA	NA
12	PacifiCorp	SF	PGE-11	NA	NA	NA
13	PaTu Wind	LU	WSPP-1	NA	NA	NA
14	Portland, City of	LU	#2821	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 2013/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.
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1	Powerex	SF	PGE-11	NA	NA	NA
2	PPL Energy Plus	SF	PGE-11	NA	NA	NA
3	PRC - Coffin Butte Biomass	LU	PRC	NA	NA	NA
4	Public Utility District No. 1 of Clark	SF	WSPP-1	NA	NA	NA
5	Puget Sound Energy	SF	WSPP-1	NA	NA	NA
6	Rainbow Energy Marketing	SF	WSPP-1	NA	NA	NA
7	Redding, City of	SF	WSPP-1	NA	NA	NA
8	Sacramento Municipal Utility District	SF	WSPP-1	NA	NA	NA
9	Salt River Project	SF	WSPP-1	NA	NA	NA
10	San Diego Gas & Electric Company	SF	WSPP-1	NA	NA	NA
11	Seattle City Light	SF	WSPP-1	NA	NA	NA
12	Shell Energy	SF	WSPP-1	NA	NA	NA
13	Sierra Pacific	SF	WSPP-1	NA	NA	NA
14	Snohomish County, PUD No. 1, Washingtn	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 2013/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Southern California Edison	SF	PGE-11	NA	NA	NA
2	Spokane Energy, LLC	LF	PGE-82	150	150	144
3	Spokane Energy, LLC	EX	PGE-82	NA	NA	NA
4	Tacoma, City of	SF	WSPP-1	NA	NA	NA
5	Tenaska	SF	WSPP-1	NA	NA	NA
6	The Energy Authority	SF	WSPP-1	NA	NA	NA
7	TransAlta Energy Marketing	SF	PGE-11	NA	NA	NA
8	TransAlta Energy Marketing	LF	PGE-11	NA	NA	NA
9	TransCanada Energy Marketing	SF	WSPP-1	NA	NA	NA
10	Turlock Irrigation District	SF	WSPP-1	NA	NA	NA
11	Vitol Inc	SF	WSPP-1	NA	NA	NA
12	Warm Springs Power Enterprises	LU	WSPP-1	NA	NA	NA
13	Western Area Power Authority	SF	WSPP-1	NA	NA	NA
14	Yamhill Solar	LU	Yamhill	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 2013/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Lake Oswego Corporation	LU	201	NA	NA	NA
2	Country Village Estates	OS	201	NA	NA	NA
3	Domaine Drouhin	OS	201	NA	NA	NA
4	Von Land Co	OS	201	NA	NA	NA
5	Minikahada Hydropower Co	OS	201	NA	NA	NA
6	Starbucks	OS	201	NA	NA	NA
7	SunWay LLC	LU	201	NA	NA	NA
8	Solar Payment Option	OS	215-217	NA	NA	NA
9	Tualatin Valley Water Dist	OS	201	NA	NA	NA
10	Oregon Heat	OS	203	NA	NA	NA
11	Load Curtailment Program			NA	NA	NA
12	Margin on Electric Financials			NA	NA	NA
13	Reserve Trading Credit Risk			NA	NA	NA
14	Green Power			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 2013/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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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	REC Retirement Expense			NA	NA	NA
2	Carbon Allowance Expense			NA	NA	NA
3						
4	Non-cash exchanges					
5	Energy Storage Expense					
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a 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.
(g)	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
39,986				3,336,495		3,336,495	1
154,000				5,068,681		5,068,681	2
1,868							3
1,834				178,046		178,046	4
620				25,240		25,240	5
291,526				8,488,277		8,488,277	6
711,446				26,253,053		26,253,053	7
990				28,475		28,475	8
215,458				2,037,431		2,037,431	9
1,165,848				35,595,420		35,595,420	10
28,008				1,099,402		1,099,402	11
222,687				8,433,630		8,433,630	12
15,200				717,154		717,154	13
4,243				105,136		105,136	14
12,159,558	457,500	456,795	20,020,200	386,262,941	35,519,130	441,802,271	

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 2013/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.
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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.
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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)	
41,002				938,913		938,913	1
71,139				4,721,409		4,721,409	2
9,656				266,182		266,182	3
818,255				8,902,595		8,902,595	4
215,973				6,129,928		6,129,928	5
47,017				1,944,481		1,944,481	6
172,350				6,216,271		6,216,271	7
64,297				3,879,644		3,879,644	8
			1,030,200			1,030,200	9
558							10
145,727				5,192,960		5,192,960	11
	26,100	26,070					12
47,286				1,874,452		1,874,452	13
2,282				96,243		96,243	14
12,159,558	457,500	456,795	20,020,200	386,262,941	35,519,130	441,802,271	

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 2013/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.
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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)	
				-660		-660	1
382,328							2
368,854				13,513,735		13,513,735	3
175,056				3,986,065		3,986,065	4
419,344				14,334,481		14,334,481	5
209,763				10,780,811		10,780,811	6
18,421				542,406		542,406	7
12,200				316,448		316,448	8
1,786				94,425		94,425	9
2,132,904				65,875,213		65,875,213	10
14,906				386,837		386,837	11
620				831,598		831,598	12
103,441				3,768,598		3,768,598	13
30				1,180		1,180	14
12,159,558	457,500	456,795	20,020,200	386,262,941	35,519,130	441,802,271	

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 2013/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.

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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)	
133,396				4,570,454		4,570,454	1
89				3,870		3,870	2
1,255				33,035		33,035	3
278,435				10,624,576		10,624,576	4
20,400				696,086		696,086	5
800				25,600		25,600	6
40,214				1,774,842		1,774,842	7
20,971				1,312,794		1,312,794	8
49,376				1,405,709		1,405,709	9
10,605				947,725		947,725	10
11,446				1,075,903		1,075,903	11
281,678				8,363,083		8,363,083	12
36,762				2,558,130		2,558,130	13
59,950				5,317,529		5,317,529	14
12,159,558	457,500	456,795	20,020,200	386,262,941	35,519,130	441,802,271	

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 2013/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.
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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)	
91,991				4,423,302		4,423,302	1
77,246				2,449,791		2,449,791	2
44,065				1,939,499		1,939,499	3
22,506				535,363		535,363	4
192,172				6,181,498		6,181,498	5
1,600				53,100		53,100	6
82				848		848	7
8,143				370,314		370,314	8
25				1,700		1,700	9
1,912				22,581		22,581	10
130,208				4,166,242		4,166,242	11
179,907				4,998,526		4,998,526	12
900				39,206		39,206	13
38,986				897,443		897,443	14
12,159,558	457,500	456,795	20,020,200	386,262,941	35,519,130	441,802,271	

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 2013/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.

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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)	
144,911				2,633,310		2,633,310	1
			18,990,000			18,990,000	2
	431,400	430,725					3
13,657				489,064		489,064	4
250				4,425		4,425	5
109,365				2,622,140		2,622,140	6
351,489				13,709,431		13,709,431	7
872,783				36,154,827		36,154,827	8
11,763				369,935		369,935	9
35,623				804,572		804,572	10
14,000				503,028		503,028	11
527,660				17,337,557		17,337,557	12
1,367				30,469		30,469	13
1,338				129,676		129,676	14
12,159,558	457,500	456,795	20,020,200	386,262,941	35,519,130	441,802,271	

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

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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)	
223				15,245		15,245	1
44				1,805		1,805	2
114				3,931		3,931	3
117				5,509		5,509	4
369				29,084		29,084	5
29				2,378		2,378	6
3,156				258,540		258,540	7
6,733				400,832		400,832	8
231				7,779		7,779	9
307					12,807	12,807	10
					608,647	608,647	11
					28,179,989	28,179,989	12
					23,935	23,935	13
					6,266,927	6,266,927	14
12,159,558	457,500	456,795	20,020,200	386,262,941	35,519,130	441,802,271	

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

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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
					193,057	193,057	1
					167,021	167,021	2
							3
					66,747	66,747	4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
12,159,558	457,500	456,795	20,020,200	386,262,941	35,519,130	441,802,271	

Schedule Page: 326.1 Line No.: 4 Column: c
Non jurisdictional utilities.

Schedule Page: 326.1 Line No.: 5 Column: b
The Douglas County contract expires on 8/31/18.

Schedule Page: 326.1 Line No.: 10 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.: 11 Column: c
Non jurisdictional utilities.

Schedule Page: 326.2 Line No.: 2 Column: c
Non jurisdictional utilities.

Schedule Page: 326.2 Line No.: 11 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.: 4 Column: b
The NextEra contract expires 12/31/15.

Schedule Page: 326.4 Line No.: 14 Column: c
Non jurisdictional utilities.

Schedule Page: 326.5 Line No.: 2 Column: b
The Spokane Energy, LLC contract expires on 12/31/16.

Schedule Page: 326.5 Line No.: 8 Column: b
The TransAlta Energy Marketing contract expires on 9/30/16.

Schedule Page: 326.6 Line No.: 2 Column: b
Power purchased from customers who operate generation facilities with less that 100 KW capacity.

Schedule Page: 326.6 Line No.: 3 Column: b
Power purchased from customers who operate generation facilities with less that 100 KW capacity.

Schedule Page: 326.6 Line No.: 4 Column: b
Power purchased from customers who operate generation facilities with less that 100 KW capacity.

Schedule Page: 326.6 Line No.: 5 Column: b
Power purchased from customers who operate generation facilities with less that 100 KW capacity.

Schedule Page: 326.6 Line No.: 6 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: l
In accordance with Schedule 203 tariff any excess credits will be transferred to Low Income Assistance Program.

Schedule Page: 326.6 Line No.: 11 Column: l
Power purchased under Load Curtailment Program.

Schedule Page: 326.6 Line No.: 12 Column: l
Margin on electric financial transactions.

Schedule Page: 326.6 Line No.: 13 Column: l
Reserve for trading credit risk.

Schedule Page: 326.6 Line No.: 14 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.: 1 Column: l

Expense of annual REC retirement to meet RPS compliance.

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

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

Schedule Page: 326.7 Line No.: 5 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 2013.

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 2013/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	Bonneville Power Administration	LFP
3	Avista Corp. Washington Water Power	Bonneville Power Administration	CAISO	LFP
4	Bonneville Power Administration	Bonneville Power Administration	CAISO	NF
5	Bonneville Power Administration	Bonneville Power Administration	Portland General Electric	FNO
6	Bonneville Power Administration	Bonneville Power Administration	Western Oregon Electric Coop	OLF
7	Bonneville Power Administration	Bonneville Power Administration	Other TVI Pumps	OLF
8	Bonneville Power Administration	Bonneville Power Administration	Canby People's Utility District	OLF
9	Bonneville Power Administration	Bonneville Power Administration	Columbia River PUD	OLF
10	Calpine Corporation	Bonneville Power Administration	Balancing Authority of N. Calif	NF
11	Calpine Corporation	Bonneville Power Administration	CAISO	NF
12	Cargill Power Markets, LLC	Bonneville Power Administration	Balancing Authority of N. Calif	NF
13	Cargill Power Markets, LLC	CAISO	Bonneville Power Administration	SFP
14	Constellation Energy Commodities Group Inc.	Bonneville Power Administration	CAISO	NF
15	Constellation Energy Commodities Group Inc.	CAISO	Bonneville Power Administration	NF
16	EDF Trading North America LLC	Bonneville Power Administration	CAISO	NF
17	Exelon Generation Company LLC	Bonneville Power Administration	CAISO	NF
18	Iberdrola Renewables Inc.	Bonneville Power Administration	Balancing Authority of N. Calif	SFP
19	Iberdrola Renewables Inc.	Bonneville Power Administration	Bonneville Power Administration	NF
20	Iberdrola Renewables Inc.	Bonneville Power Administration	CAISO	NF
21	Iberdrola Renewables Inc.	Bonneville Power Administration	CAISO	SFP
22	Iberdrola Renewables Inc.	CAISO	Bonneville Power Administration	NF
23	Macquarie Energy LLC	Balancing Authority of N. Calif	Bonneville Power Administration	NF
24	Macquarie Energy LLC	Bonneville Power Administration	Balancing Authority of N. Calif	NF
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	NF
29	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	Balancing Authority of N. Calif	SFP
30	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	CAISO	SFP
31	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	CAISO	NF
32	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	PacifiCorp	NF
33	Morgan Stanley Capital Group Inc.	CAISO	Bonneville Power Administration	NF
34	Morgan Stanley Capital Group Inc.	CAISO	Bonneville Power Administration	SFP
	TOTAL			

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/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	OS
2	Nextera Energy Power Marketing, LLC	Bonneville Power Administration	CAISO	NF
3	Nextera Energy Power Marketing, LLC	Bonneville Power Administration	CAISO	SFP
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	Noble Americas Energy Solutions	Portland General Electric	Portland General Electric	NF
7	PUD No.1 of Grays Harbor County	Bonneville Power Administration	Balancing Authority of N. Calif	NF
8	PacifiCorp Marketing			NF
9	PacifiCorp	PacifiCorp	Portland General Electric	OLF
10	Powerex Corp.	Balancing Authority of N. Calif	Bonneville Power Administration	OS
11	Powerex Corp.	Bonneville Power Administration	Balancing Authority of N. Calif	LFP
12	Powerex Corp.	Bonneville Power Administration	Balancing Authority of N. Calif	NF
13	Powerex Corp.	Bonneville Power Administration	CAISO	NF
14	Powerex Corp.	Bonneville Power Administration	CAISO	LFP
15	Powerex Corp.	Bonneville Power Administration	PacifiCorp	LFP
16	Powerex Corp.	Bonneville Power Administration	PacifiCorp	NF
17	Powerex Corp.	CAISO	Bonneville Power Administration	OS
18	Powerex Corp.	CAISO	Bonneville Power Administration	NF
19	Puget Sound Energy	Bonneville Power Administration	Balancing Authority of N. Calif	NF
20	Puget Sound Energy	Bonneville Power Administration	Bonneville Power Administration	NF
21	Puget Sound Energy	Bonneville Power Administration	Bonneville Power Administration	LFP
22	Puget Sound Energy	Bonneville Power Administration	CAISO	OS
23	Puget Sound Energy	Bonneville Power Administration	CAISO	NF
24	Puget Sound Energy	CAISO	Bonneville Power Administration	NF
25	Puget Sound Energy	CAISO	Bonneville Power Administration	LFP
26	Puget Sound Energy	CAISO	Bonneville Power Administration	SFP
27	Sacramento Municipal Utility Dist			NF
28	San Diego Gas and Electric Co.	Bonneville Power Administration	Balancing Authority of N. Calif	OLF
29	San Diego Gas and Electric Co.	Bonneville Power Administration	CAISO	OLF
30	San Diego Gas and Electric Co.	Bonneville Power Administration	PacifiCorp	OLF
31	Seattle City Light Marketing	Balancing Authority of N. Calif	Bonneville Power Administration	NF
32	Seattle City Light Marketing	Bonneville Power Administration	Balancing Authority of N. Calif	NF
33	Seattle City Light Marketing	Bonneville Power Administration	CAISO	NF
34	Shell Energy North America (US), L.P.	Bonneville Power Administration	Balancing Authority of N. Calif	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 2013/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 Classification (d)
1	Shell Energy North America (US), L.P.	Bonneville Power Administration	Bonneville Power Administration	LFP
2	Shell Energy North America (US), L.P.	Bonneville Power Administration	CAISO	LFP
3	Shell Energy North America (US), L.P.	Bonneville Power Administration	CAISO	NF
4	Shell Energy North America (US), L.P.	Bonneville Power Administration	PacifiCorp	LFP
5	Shell Energy North America (US), L.P.	CAISO	Bonneville Power Administration	OS
6	Shell Energy North America (US), L.P.	CAISO	Bonneville Power Administration	NF
7	Shell Energy North America (US), L.P.	PacifiCorp	Bonneville Power Administration	OS
8	Southern California Edison	Bonneville Power Administration	CAISO	NF
9	Turlock Irrigation District	Bonneville Power Administration	Balancing Authority of N. Calif	NF
10	The Energy Authority	Balancing Authority of N. Calif	Bonneville Power Administration	NF
11	The Energy Authority	Bonneville Power Administration	Balancing Authority of N. Calif	NF
12	The Energy Authority	CAISO	Bonneville Power Administration	NF
13	TransAlta Energy Marketing U.S. Inc.	Bonneville Power Administration	Bonneville Power Administration	NF
14	TransAlta Energy Marketing U.S. Inc.	Bonneville Power Administration	CAISO	NF
15	TransAlta Energy Marketing U.S. Inc.	Bonneville Power Administration	PacifiCorp	NF
16	TransAlta Energy Marketing U.S. Inc.	CAISO	Bonneville Power Administration	NF
17	TransAlta Energy Marketing U.S. Inc.	CAISO	Bonneville Power Administration	SFP
18	Accrual			AD
19				
20				
21				
22				
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 2013/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		23,117	23,117	1
8	John Day	COBH		984	984	2
8	John Day	Malin 500		591,310	591,310	3
8	John Day	Malin 500		1,021	1,021	4
8	BPAT.PGE	PGE		88,992	51,020	5
72	Various Subs	Various Subs		12,834	12,857	6
72	Various Subs	Various Subs		6,805	6,817	7
72	Various Subs	Various Subs		180,842	181,171	8
72	Various Subs	Various Subs		221,542	221,945	9
8	John Day	Captain Jack		30	30	10
8	John Day	Malin 500		40	40	11
8	John Day	Captain Jack		80	80	12
8	Malin 500	John Day		400	400	13
8	John Day	Malin 500		6,921	6,921	14
8	Malin 500	John Day		2	2	15
8	John Day	Malin 500		25	25	16
8	John Day	Malin 500		4,458	4,458	17
8	John Day	Captain Jack		7,241	7,241	18
8	K Falls Gen	John Day		45	45	19
8	John Day	Malin 500		174	174	20
8	John Day	Malin 500		6,957	6,957	21
8	Malin 500	John Day		915	915	22
8	Captain Jack	John Day		50	50	23
8	John Day	Captain Jack		451	451	24
8	John Day	Malin 500		47,218	47,218	25
8	Malin 500	John Day		1,814	1,814	26
8	Malin 500	John Day		3,795	3,795	27
8	John Day	Captain Jack		19,943	19,943	28
8	John Day	Captain Jack		111,890	111,890	29
8	John Day	Malin 500		54,318	54,318	30
8	John Day	Malin 500		20,249	20,249	31
8	John Day	Malin 500		204	204	32
8	Malin 500	John Day		1,668	1,668	33
8	Malin 500	John Day		1,200	1,200	34
			3,095	**5,661,295**	**5,161,463**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/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		243	243	1
8	John Day	Malin 500		36,272	36,272	2
8	John Day	Malin 500		10,809	10,809	3
8	BPAT.PGE	PGE	2,919	1,575,119	1,138,813	4
8	BPAT.PGE	PGE		25	16	5
8	PGE.Internal	PGE	176	95,125	68,774	6
8	John Day	Captain Jack		18	18	7
8	PGE	BPAT.PGE				8
	John Day	Various Subs		2,168	2,207	9
8	Captain Jack	John Day		86	86	10
8	John Day	Captain Jack		49,513	49,513	11
8	John Day	Captain Jack		13,945	13,945	12
8	John Day	Malin 500		21,345	21,345	13
8	John Day	Malin 500		1,268,747	1,268,747	14
8	John Day	Malin 500		1,869	1,869	15
8	John Day	Malin 500		1,229	1,229	16
8	Malin 500	John Day		383	383	17
8	Malin 500	John Day		6,425	6,425	18
8	John Day	Captain Jack		210	210	19
8	K Falls Gen	John Day		145	145	20
8	K Falls Gen	John Day		10,894	10,894	21
8	John Day	Malin 500		3,949	3,949	22
8	John Day	Malin 500		259	259	23
8	Malin 500	John Day		47,036	47,036	24
8	Malin 500	John Day		13,815	13,815	25
8	Malin 500	John Day		33,599	33,599	26
8	John Day	COBH				27
8	John Day	Captain Jack		924	924	28
8	John Day	Malin 500		48,873	48,873	29
8	John Day	Malin 500		17	17	30
8	Captain Jack	John Day		100	100	31
8	John Day	Captain Jack		1,827	1,827	32
8	John Day	Malin 500		550	550	33
8	John Day	Captain Jack		169,296	169,296	34
			3,095	**5,661,295**	**5,161,463**	

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 2013/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	COBH		400	400	1
8	John Day	Malin 500		742,243	742,243	2
8	John Day	Malin 500		1,057	1,057	3
8	John Day	Malin 500		1,169	1,169	4
8	Malin 500	John Day		1,750	1,750	5
8	Malin 500	John Day		1,529	1,529	6
8	Malin 500	John Day		95	95	7
8	John Day	Malin 500		10,207	10,207	8
8	John Day	Captain Jack		10,429	10,429	9
8	Captain Jack	John Day		1,710	1,710	10
8	John Day	Captain Jack		9,470	9,470	11
8	Malin 500	John Day		7,087	7,087	12
8	K Falls Gen	John Day		25	25	13
8	John Day	Malin 500		13,025	13,025	14
8	John Day	Malin 500		234	234	15
8	Malin 500	John Day		16,122	16,122	16
8	Malin 500	John Day		12,393	12,393	17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			3,095	**5,661,295**	**5,161,463**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/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.
	24,153		24,153	1
	1,028		1,028	2
	617,808		617,808	3
	2,184		2,184	4
78,914		21,582	100,496	5
	60,100		60,100	6
	16,961		16,961	7
	255,624		255,624	8
	37,591		37,591	9
	39		39	10
	52		52	11
	59		59	12
	510		510	13
	7,864		7,864	14
	2		2	15
	32		32	16
	4,221		4,221	17
	10		10	18
	73		73	19
	280		280	20
	10		10	21
	1,474		1,474	22
	54		54	23
	489		489	24
	51,185		51,185	25
	1,966		1,966	26
	9,695		9,695	27
	27,081		27,081	28
	115,046		115,046	29
	55,850		55,850	30
	27,497		27,497	31
	277		277	32
	2,265		2,265	33
	1,234		1,234	34
1,591,878	**5,897,050**	**200,116**	**7,689,044**	

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
				1
	43,279		43,279	2
	59,373		59,373	3
1,426,779			1,426,779	4
20			20	5
86,165			86,165	6
	26		26	7
	1		1	8
		247,193	247,193	9
				10
	63,184		63,184	11
	28,910		28,910	12
	44,251		44,251	13
	1,619,062		1,619,062	14
	2,385		2,385	15
	2,548		2,548	16
				17
	13,320		13,320	18
	212		212	19
	146		146	20
	212,617		212,617	21
				22
	262		262	23
	47,503		47,503	24
	269,625		269,625	25
	188,451		188,451	26
	55		55	27
	12,057		12,057	28
	637,721		637,721	29
	222		222	30
	112		112	31
	2,047		2,047	32
	616		616	33
	227,420		227,420	34
1,591,878	**5,897,050**	**200,116**	**7,689,044**	

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 2013/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.
	537		537	1
	997,077		997,077	2
	1,287		1,287	3
	1,570		1,570	4
				5
	1,861		1,861	6
				7
	11,590		11,590	8
	11,288		11,288	9
	1,815		1,815	10
	10,049		10,049	11
	7,520		7,520	12
	30		30	13
	15,384		15,384	14
	276		276	15
	19,042		19,042	16
	19,605		19,605	17
		-68,659	-68,659	18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
1,591,878	**5,897,050**	**200,116**	**7,689,044**	

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.: 3 Column: d
Contract with Avista Corporation Washington Water Power Division expires 01/01/2023.

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.: 8 Column: d
Contract with Bonneville Power Administration continues until terminated.

Schedule Page: 328 Line No.: 9 Column: d
Contract with Bonneville Power Administration continues until terminated.

Schedule Page: 328.1 Line No.: 1 Column: d
Represents non-billed redirected MWHs of Morgan Stanley Capital Group Inc.'s service.

Schedule Page: 328.1 Line No.: 8 Column: b
PacificCorp Marketing submitted transmission reservations but did not schedule energy.

Schedule Page: 328.1 Line No.: 8 Column: c
PacificCorp Marketing submitted transmission reservations but did not schedule energy.

Schedule Page: 328.1 Line No.: 9 Column: d
Exchange agreement with Pacificorp.

Schedule Page: 328.1 Line No.: 9 Column: e
Exchange agreement with Pacificorp. No tariff applicable to exchange agreement.

Schedule Page: 328.1 Line No.: 9 Column: m
Represents monthly facility usage charges.

Schedule Page: 328.1 Line No.: 10 Column: d
Represents non-billed redirected MWHs of Powerex Corp.'s service.

Schedule Page: 328.1 Line No.: 11 Column: d
Contract with Powerex Corp. expires 01/01/2017.

Schedule Page: 328.1 Line No.: 14 Column: d
Contract with Powerex Corp. expires 01/01/2017.

Schedule Page: 328.1 Line No.: 15 Column: d
Contract with Powerex Corp. expires 01/01/2017.

Schedule Page: 328.1 Line No.: 17 Column: d
Represents non-billed redirected MWHs of Powerex Corp.'s service.

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

Schedule Page: 328.1 Line No.: 25 Column: d
Contract with Puget Sound Energy expires 01/01/2017.

Schedule Page: 328.1 Line No.: 27 Column: b
Sacramento Municipal Utility Dist submitted transmission reservations but did not schedule energy.

Schedule Page: 328.1 Line No.: 27 Column: c
Sacramento Municipal Utility Dist submitted transmission reservations but did not schedule energy.

Schedule Page: 328.1 Line No.: 28 Column: d
Contract with San Diego Gas & Electric expired 12/13/2013.

Schedule Page: 328.1 Line No.: 29 Column: d
Contract with San Diego Gas & Electric expired 12/13/2013.

Schedule Page: 328.1 Line No.: 30 Column: d
Contract with San Diego Gas & Electric expired 12/13/2013.

Schedule Page: 328.1 Line No.: 34 Column: d
Contract with Shell Energy North America (US), L.P. expires 01/01/2022.

Schedule Page: 328.2 Line No.: 1 Column: d
Contract with Shell Energy North America (US), L.P. expires 01/01/2022.

Schedule Page: 328.2 Line No.: 2 Column: d
Contract with Shell Energy North America (US), L.P. expires 01/01/2022.

Schedule Page: 328.2 Line No.: 4 Column: d
Contract with Shell Energy North America (US), L.P. expires 01/01/2022.

Schedule Page: 328.2 Line No.: 5 Column: d
Represents non-billed redirected MWHs of Shell Energy North America (US), L.P.'s service.

Schedule Page: 328.2 Line No.: 7 Column: d
Represents non-billed redirected MWHs of Shell Energy North America (US), L.P.'s service.

Schedule Page: 328.2 Line No.: 18 Column: d
Represents the difference between actual transmission revenue for the period as reflected on the individual line items within this schedule, and the accruals credited during the period to FERC Account 456.1, Revenues from Transmission of Electricity for Others.

Schedule Page: 328.2 Line No.: 18 Column: m
Represents the difference between actual transmission revenue for the period as reflected on the individual line items within this schedule, and the accruals credited during the period to FERC Account 456.1, Revenues from Transmission of Electricity for Others.

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or “true-ups” for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
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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 2013/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	Avista Corp	NF	1,033	1,033		5,960		5,960
2	Bonneville Power Admin	LFP			57,386,641			57,386,641
3	Bonneville Power Admin	OS					14,485,544	14,485,544
4	Bonneville Power Admin	SFP	60,222	60,222		164,774		164,774
5	Bonneville Power Admin	NF	40,964	40,964		166,988		166,988
6	Columbia River PUD	NF	12	12		5,157		5,157
7	Fale-Safe, Inc	OS					280,136	280,136
8	Idaho Power Company	NF	10,923	10,923		39,537		39,537
9	Los Angeles Dept. Water	NF	3,872	3,872		45,371		45,371
10	McMinnville Water & Lig	NF	744	744		14,453		14,453
11	Montana, State of	OS					1,306,596	1,306,596
12	Morgan Stanley	NF	232,675	232,675		360,060		360,060
13	NV Energy	NF	2,621	2,621		16,214		16,214
14	Northwest Power Pool	OS					92	92
15	Northwestern Corp	NF	11,989	11,989		76,848		76,848
16	PacifiCorp	OS					103,752	103,752
	TOTAL		386,605	386,605	57,386,641	992,941	16,176,120	74,555,702

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 2013/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	PacifiCorp	NF	16,362	16,362		78,352		78,352
2	Puget Sound Energy	NF	227	227		1,257		1,257
3	Salt River Project	NF	336	336		705		705
4	Sierra Pacific	NF	961	961		8,222		8,222
5	WAPA	NF	3,664	3,664		9,043		9,043
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		386,605	386,605	57,386,641	992,941	16,176,120	74,555,702

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

The Bonneville Power Administration PTP Network contract expires on 12/31/2019. The PTP contract for Slatt expired on 12/31/2013, 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.: 3 Column: g

Represents Bonneville Power Administration Ancillary Transmission Services.

Schedule Page: 332 Line No.: 7 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.: 11 Column: g

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

Schedule Page: 332 Line No.: 14 Column: g

Represents Ancillary Services under the Pacific Northwest Coordinating Agreement.

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 2013/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	2,250,571
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	736,269
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	1,521,437
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Involuntary Severance	889,028
7	Directors Pension	66,612
8	Directors Fees & Expenses	200,369
9	Directors & Officers Expenses	2,147,718
10	Misc Admin R&D Expenses	12,732
11	Misc Admin Expenses	171,395
12	Colstrip-PPL Montana	444,028
13	Internal & External Reporting	110,308
14	Bull Run PME-Decommissioning	173,435
15		
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45		
46	TOTAL	8,723,902

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 2013/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			22,054,865		22,054,865
2	Steam Production Plant	22,807,920	3,224,887			26,032,807
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	11,419,190	45			11,419,235
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	50,353,935	-118,299			50,235,636
7	Transmission Plant	9,841,788	419			9,842,207
8	Distribution Plant	113,778,664	662,405			114,441,069
9	Regional Transmission and Market Operation					
10	General Plant	20,484,569	2,071			20,486,640
11	Common Plant-Electric					
12	TOTAL	228,686,066	3,771,528	22,054,865		254,512,459

B. Basis for Amortization Charges

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							
18							
19							
20							
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50							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/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		196,104	196,104	
2	Docket No. RM06-16				
3					
4	FERC-NERC Reliability		128,657	128,657	
5	Docket No. RM06-22				
6					
7	OPUC-2014 General Rate Case		202,310	202,310	
8	Docket No. UE 262				
9					
10	OPUC-2012 RFP Proposal for Capacity and		167,415	167,415	
11	Baseload Energy Resources				
12	Docket No. UM 1535				
13					
14	OPUC-Investigation into the Evaluation of		118,398	118,398	
15	Decoupling Mechanism				
16	Docket No. UM 1644				
17					
18	OPUC-Complaint of PATU Wind Farm LLC. against		70,851	70,851	
19	Portland General Electric Company, Pursuant				
20	ORS 756.500.				
21	Docket No. UM 1566				
22					
23	OPUC-2015 General Rate Case		90,157	90,157	
24	Docket No. UE 283				
25					
26	OPUC-2008 Trojan Appeal		64,719	64,719	
27	Docket No. UE 88				
28					
29	OPUC-Investigation into Competitive Bidding		44,815	44,815	
30	Docket No. UM 1182				
31					
32	OPUC matters less than $25,000		114,753	114,753	
33					
34	FERC matters less than $25,000		24,660	24,660	
35					
36	Non Docs matters		211,620	211,620	
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL		1,434,459	1,434,459	

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 2013/Q4

REGULATORY COMMISSION EXPENSES (Continued)

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

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
	928	196,104					1
							2
							3
	928	128,657					4
							5
							6
	928	202,310					7
							8
							9
	928	167,415					10
							11
							12
							13
	928	118,398					14
							15
							16
							17
	928	70,851					18
							19
							20
							21
							22
	928	90,157					23
							24
							25
	928	64,719					26
							27
							28
	928	44,815					29
							30
							31
	928	114,753					32
							33
	928	24,660					34
							35
	928	211,620					36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		1,434,459					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 2013/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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20		
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23		
24		
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26	Totals	
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37		
38		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

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

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

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

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

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

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

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
					3
					4
484,479		930.2	484,479		5
					6
111,675		930.2	111,675		7
50,000		930.2	50,000		8
	90,115	930.2	90,115		9
					10
					11
					12
					13
					14
					15
					16
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					18
					19
					20
					21
					22
					23
					24
					25
646,154	90,115		736,269		26
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					36
					37
					38

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 2013/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	26,466,042		
4	Transmission	3,653,827		
5	Regional Market			
6	Distribution	18,007,897		
7	Customer Accounts	23,165,021		
8	Customer Service and Informational	6,542,078		
9	Sales			
10	Administrative and General	43,710,765		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	121,545,630		
12	Maintenance			
13	Production	10,640,874		
14	Transmission	1,268,133		
15	Regional Market			
16	Distribution	18,573,300		
17	Administrative and General	747,372		
18	TOTAL Maintenance (Total of lines 13 thru 17)	31,229,679		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	37,106,916		
21	Transmission (Enter Total of lines 4 and 14)	4,921,960		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	36,581,197		
24	Customer Accounts (Transcribe from line 7)	23,165,021		
25	Customer Service and Informational (Transcribe from line 8)	6,542,078		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	44,458,137		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	152,775,309	14,142,529	166,917,838
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)	152,775,309	14,142,529	166,917,838
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	63,358,920	4,764,259	68,123,179
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	63,358,920	4,764,259	68,123,179
72	Plant Removal (By Utility Departments)			
73	Electric Plant	1,381,445	52,482	1,433,927
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	1,381,445	52,482	1,433,927
77	Other Accounts (Specify, provide details in footnote):			
78	Other Income and Deductions	1,991,235	167,145	2,158,380
79	Co-Owner Shares of Generating Facilities	6,399,640	265,778	6,665,418
80	Other	564,338	3,473,298	4,037,636
81	Payroll Allocated	22,865,491	-22,865,491	
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	31,820,704	-18,959,270	12,861,434
96	TOTAL SALARIES AND WAGES	249,336,378		249,336,378

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 2013/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)	483,818	576,545	283,699	2,037,431
3	Net Sales (Account 447)	6,436,461	7,787,287	6,556,709	26,434,223
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
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8					
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44					
45					
46	TOTAL	6,920,279	8,363,832	6,840,408	28,471,654

PURCHASES AND SALES OF ANCILLARY SERVICES

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

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

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

Line No.	Type of Ancillary Service (a)	Amount Purchased for the Year — Usage - Related Billing Determinant: Number of Units (b)	Unit of Measure (c)	Dollars (d)	Amount Sold for the Year — Usage - Related Billing Determinant: Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	46,284	MW	15,324,118	5,755,147	Various	140,832
2	Reactive Supply and Voltage				3,101,614	Various	99,663
3	Regulation and Frequency Response				3,095,125	Various	232,065
4	Energy Imbalance	14,906	MWh	307,866	18,381	MWh	636,385
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other						
8	Total (Lines 1 thru 7)	61,190		15,631,984	11,970,267		1,108,945

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

Scheduling, System Control and Dispatch	**No of Units**	**Amount**
MW Day	56,291	6,229
MW Hour	219,518	5,131
MW Month	183	2,286
MW Week	2,016	829
MW Year	2,382,197	95,480
Sum of Peak Demand (KW)	3,094,942	30,877
	5,755,147	**140,832**

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

Reactive Supply and Voltage	**No of Units**	**Amount**
MW Hour	6,489	6
MW Month	183	7,027
Sum of Peak Demand (KW)	3,094,942	92,630
	3,101,614	**99,663**

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

Regulation and Frequency Response	**No of Units**	**Amount**
MW Month	183	15,927
Sum of Peak Demand (KW)	3,094,942	216,138
	3,095,125	**232,065**

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.: 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 2013/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	4,343	14	1800	3,280	229	1,162	13	4,227	24
2	February	4,017	20	1900	2,849	222	1,162	13	4,227	75
3	March	3,993	4	800	2,825	217	1,162	13	4,227	122
4	Total for Quarter 1	12,353			8,954	668	3,486	39	12,681	221
5	April	3,733	17	800	2,529	209	1,162	13	4,227	
6	May	3,610	3	1800	2,224	231	1,162	13	4,227	70
7	June	4,317	30	1800	3,050	244	1,162	13	4,227	12
8	Total for Quarter 2	11,660			7,803	684	3,486	39	12,681	82
9	July	4,655	1	1700	3,242	345	1,162	13	4,227	762
10	August	4,327	5	1800	3,114	331	1,162	13	4,227	
11	September	4,158	11	1700	3,259	327	1,162	13	4,227	70
12	Total for Quarter 3	13,140			9,615	1,003	3,486	39	12,681	832
13	October	3,534	28	1900	2,641	197	1,162	13	4,227	55
14	November	3,799	15	1800	2,806	199	1,162	13	4,227	
15	December	4,850	9	1800	3,731	135	1,162	13	4,392	294
16	Total for Quarter 4	12,183			9,178	531	3,486	39	12,846	349
17	Total Year to Date/Year	49,336			35,550	2,886	13,944	156	50,889	1,484

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 2013/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	31	100			307			
2	February	292	22	100			307			
3	March	292	30	600			307			
4	Total for Quarter 1	873					921			
5	April	294	12	400			307			
6	May	287	5	1300			307			
7	June	286	28	300			307			
8	Total for Quarter 2	867					921			
9	July	221	1	2100			307			
10	August	195	3	2400			307			
11	September	167	8	1700			307			
12	Total for Quarter 3	583					921			
13	October	213	13	2400			307			
14	November	189	28	2000			307			
15	December	182	22	1300			307			
16	Total for Quarter 4	584					921			
17	Total Year to Date/Year	2,907					3,684			

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

Long Term Firm Point-to-Point Reservations: Q1

Reservation #	Customer	MW Granted Jan 2013	MW Granted Feb 2013	MW Granted Mar 2013	Earliest Termination Date
432190	Portland General Electric Co.	100	100	100	01/01/2022
71324505	Powerex	165	165	165	06/01/2013
71472976	Shell Energy NA	200	200	200	01/01/2022
71915367	Powerex	97	97	97	01/01/2017
74382640	Portland General Electric Co.	100	100	100	07/01/2017
74566698	Portland General Electric Co.	100	100	100	01/01/2022
75731986	Puget Sound Energy Marketing	100	100	100	01/01/2017
76412778	Portland General Electric Co.	200	200	200	01/01/2017
77316434	Avista Corp. Washington Water Power Division	100	100	100	01/01/2023
	Total	**1,162**	**1,162**	**1,162**	

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

Other Long Term Service: Q1

Reservation #	Customer	MW Granted Jan 2013	MW Granted Feb 2013	MW Granted Mar 2013	Earliest Termination Date
Grandfathered	SEMPRA (San Diego Gas & Electric)	13	13	13	12/31/2013

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 2013	MW Granted Feb 2013	MW Granted Mar 2013
77715459	Portland General Electric Co.	3,300		
77715538	Portland General Electric Co.	200		
77715545	Portland General Electric Co.	25		
77715551	Portland General Electric Co.	500		
77715553	Portland General Electric Co.	200		
77715554	Portland General Electric Co.	2		
77809235	Portland General Electric Co.		200	200
77809241	Portland General Electric Co.		25	25
77809258	Portland General Electric Co.		500	500
77809265	Portland General Electric Co.		200	200
77809266	Portland General Electric Co.		2	2
77809273	Portland General Electric Co.		3,300	
77902913	Portland General Electric Co.			3,300
	Total	**4,227**	**4,227**	**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 2013	MW Granted May 2013	MW Granted Jun 2013	Earliest Termination Date
432190	Portland General Electric Co.	100	100	100	01/01/2022
71324505	Powerex	165	165	165	06/01/2018
71472976	Shell Energy NA	200	200	200	01/01/2022
71915367	Powerex	97	97	97	01/01/2017
74382640	Portland General Electric Co.	100	100	100	07/01/2017
74566698	Portland General Electric Co.	100	100	100	01/01/2022
75731986	Puget Sound Energy Marketing	100	100	100	01/01/2017
76412778	Portland General Electric Co.	200	200	200	01/01/2017
77316434	Avista Corp. Washington Water Power Division	100	100	100	01/01/2023
	Total	**1,162**	**1,162**	**1,162**	

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

Other Long Term Service: Q2

Reservation #	Customer	MW Granted Apr 2013	MW Granted May 2013	MW Granted Jun 2013	Earliest Termination Date
Grandfathered	SEMPRA (San Diego Gas & Electric)	13	13	13	12/31/2013

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 2013	MW Granted May 2013	MW Granted Jun 2013
77809235	Portland General Electric Co.	200	200	200
77809241	Portland General Electric Co.	25	25	25
77809258	Portland General Electric Co.	500	500	500
77809265	Portland General Electric Co.	200	200	200
77809266	Portland General Electric Co.	2	2	2
78010202	Portland General Electric Co.	3,300		
78124933	Portland General Electric Co.		3,300	
78258938	Portland General Electric Co.			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 2013	MW Granted Aug 2013	MW Granted Sep 2013	Earliest Termination Date
432190	Portland General Electric Co.	100	100	100	01/01/2022
71472976	Shell Energy NA	200	200	200	01/01/2022
74382640	Portland General Electric Co.	100	100	100	07/01/2017
74566698	Portland General Electric Co.	100	100	100	01/01/2022
75731986	Portland General Electric Co.	100	100	100	01/01/2017
76412778	Portland General Electric Co.	200	200	200	01/01/2017
77316434	Avista Corp. Washington Water Power Division	100	100	100	01/01/2023
78032049	Powerex	262	262	262	01/01/2014
	Total	**1,162**	**1,162**	**1,162**	

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

Other Long Term Service: Q3

Reservation #	Customer	MW Granted Jul 2013	MW Granted Aug 2013	MW Granted Sep 2013	Earliest Termination Date
Grandfathered	SEMPRA (San Diego Gas & Electric)	13	13	13	12/31/2013

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 2013	MW Granted Aug 2013	MW Granted Sep 2013
77809235	Portland General Electric Co.	200	200	200
77809241	Portland General Electric Co.	25	25	25
77809258	Portland General Electric Co.	500	500	500
77809265	Portland General Electric Co.	200	200	200
77809266	Portland General Electric Co.	2	2	2
78390272	Portland General Electric Co.	3,300		
78526372	Portland General Electric Co.		3,300	
78645497				3,300
	Total	**4,227**	**4,227**	**4,227**

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 2013	MW Granted Nov 2013	MW Granted Dec 2013	Earliest Termination Date
315999	Avista Energy, Inc.	200	200	200	01/01/2022
432190	Portland General Electric Co.	100	100	100	01/01/2022
71915367	Powerex	97	97	97	01/01/2017
74382640	Portland General Electric Co.	100	100	100	07/01/2017
74566698	Portland General Electric Co.	100	100	100	01/01/2022
75731986	Puget Sound Energy	100	100	100	01/01/2017
76412778	Portland General Electric Co.	200	200	200	01/01/2017
77316434	Avista Corp. Washington Water Power Division	100	100	100	01/01/2023
77594664	Powerex	165	165	165	06/01/2018
	Total	**1,162**	**1,162**	**1,162**	

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

Other Long Term Service: Q4

Reservation #	Customer	MW Granted Oct 2013	MW Granted Nov 2013	MW Granted Dec 2013	Earliest Termination Date
Grandfathered	SEMPRA (San Diego Gas & Electric)	13	13	13	12/31/2013

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 2013	MW Granted Nov 2013	MW Granted Dec 2013
77809235	Portland General Electric Co.	200	200	200
77809241	Portland General Electric Co.	25	25	25
77809258	Portland General Electric Co.	500	500	500
77809265	Portland General Electric Co.	200	200	200
77809266	Portland General Electric Co.	2	2	2
78760065	Portland General Electric Co.	3,300		
78845077	Portland General Electric Co.		3,300	
78988411	Portland General Electric Co.			3,300
79037108	Transalta Energy Marketing U.S. Inc.			165
	Total	**4,227**	**4,227**	**4,392**

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

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

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

Long Term Firm Point-to-Point Reservations: Q1

Reservation #	Customer	MW Granted Jan 2013	MW Granted Feb 2013	MW Granted Mar 2013	Earliest Termination Date
76059414	Portland General Electric Co.	307	307	307	07/01/2022

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

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

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

Long Term Firm Point-to-Point Reservations: Q2

Reservation #	Customer	MW Granted Apr 2013	MW Granted May 2013	MW Granted Jun 2013	Earliest Termination Date
76059414	Portland General Electric Co.	307	307	307	07/01/2022

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

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

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

Long Term Firm Point-to-Point Reservations: Q3

Reservation #	Customer	MW Granted Jul 2013	MW Granted Aug 2013	MW Granted Sep 2013	Earliest Termination Date
76059414	Portland General Electric Co.	307	307	307	07/01/2022

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

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

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

Long Term Firm Point-to-Point Reservations: Q4

Reservation #	Customer	MW Granted Oct 2013	MW Granted Nov 2013	MW Granted Dec 2013	Earliest Termination Date
76059414	Portland General Electric Co.	307	307	307	07/01/2022

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 2013/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)
1	SOURCES OF ENERGY	
2	Generation (Excluding Station Use):	
3	Steam	4,069,602
4	Nuclear	
5	Hydro-Conventional	1,646,105
6	Hydro-Pumped Storage	
7	Other	4,575,191
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	10,290,898
10	Purchases	12,159,558
11	Power Exchanges:	
12	Received	457,500
13	Delivered	456,795
14	Net Exchanges (Line 12 minus line 13)	705
15	Transmission For Other (Wheeling)	
16	Received	5,661,295
17	Delivered	5,161,463
18	Net Transmission for Other (Line 16 minus line 17)	499,832
19	Transmission By Others Losses	
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	22,950,993

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	17,673,447
23	Requirements Sales for Resale (See instruction 4, page 311.)	
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	3,553,416
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	25,695
27	Total Energy Losses	1,698,435
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	22,950,993

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 2013/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	2,066,323	203,872	3,490	14	1800
30	February	1,694,271	161,760	3,056	20	1900
31	March	1,885,300	314,255	3,026	4	800
32	April	1,865,805	431,250	2,750	15	800
33	May	1,866,297	431,332	2,762	6	1800
34	June	1,996,365	600,821	3,281	30	1800
35	July	1,973,991	410,467	3,527	1	1800
36	August	1,799,658	225,984	3,361	5	1800
37	September	1,668,931	221,479	3,514	11	1700
38	October	1,677,501	173,078	2,896	30	800
39	November	1,805,576	213,272	3,198	21	1900
40	December	2,151,143	210,545	3,869	9	1900
41	TOTAL	22,451,161	3,598,115			

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

In addition to the generation from the Beaver, Port Westward and Coyote Springs steam generation plants, as shown on page 403, Other Generation includes 1,199,947_megawatt hours of net wind energy scheduled and delivered by Bonneville Power Administration (BPA)from PGE's Biglow Canyon Wind Project. Actual net wind generation from the project to BPA was 1,190,817 magawatt hours. This project was placed in service in three phases between December 2007 and August 2010. Key statistics include the following:

In-service production cost at 12/31/2013:	$921,288,820
Total installed capactiy:	450 megawatts
Operations and maintenance expenses for 2013:	$ 21,960,823

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

Includes <1 MWH of Energy Stored at the Salem Smart Grid Demonstration Project. This will be reported on a separate line in future FERC filings.

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 2013/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 (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	513.76
6	Net Peak Demand on Plant - MW (60 minutes)	578	0
7	Plant Hours Connected to Load	7253	0
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	708	0
10	When Limited by Condenser Water	575	0
11	Average Number of Employees	113	0
12	Net Generation, Exclusive of Plant Use - KWh	3733393000	2454997000
13	Cost of Plant: Land and Land Rights	1274078	832853
14	Structures and Improvements	158631187	104930863
15	Equipment Costs	579275460	381770601
16	Asset Retirement Costs	40928681	32401351
17	Total Cost	780109406	519935668
18	Cost per KW of Installed Capacity (line 17/5) Including	1214.7453	1012.0205
19	Production Expenses: Oper, Supv, & Engr	3195671	1945523
20	Fuel	71128121	47744397
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	5162929	3268230
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	5609481	3637867
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	448534	282052
30	Maintenance of Structures	388537	249734
31	Maintenance of Boiler (or reactor) Plant	2264007	1463238
32	Maintenance of Electric Plant	17221525	10991172
33	Maintenance of Misc Steam (or Nuclear) Plant	179653	118113
34	Total Production Expenses	105598458	69700326
35	Expenses per Net KWh	0.0283	0.0284

Line No.	Item (a)	(b)			(c)		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil				
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels				
38	Quantity (Units) of Fuel Burned	2182985	9327	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	33.521	128.576	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	32.013	133.418	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	1.879	22.905	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.019	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	9960.100	0.000	0.000	0.000	0.000	0.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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

Line No.	Item (a)	Plant Name: (b)			Plant Name: *Colstrip* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear				Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			311.20		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			1614605000		
13	Cost of Plant: Land and Land Rights	0			3327818		
14	Structures and Improvements	0			115138882		
15	Equipment Costs	0			329404805		
16	Asset Retirement Costs	0			-285471		
17	Total Cost	0			447586034		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			1438.2585		
19	Production Expenses: Oper, Supv, & Engr	0			210133		
20	Fuel	0			25172697		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			1662182		
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			2013455		
27	Rents	0			40452		
28	Allowances	0			136368		
29	Maintenance Supervision and Engineering	0			467295		
30	Maintenance of Structures	0			769868		
31	Maintenance of Boiler (or reactor) Plant	0			5274185		
32	Maintenance of Electric Plant	0			1065081		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			675692		
34	Total Production Expenses	0			37487408		
35	Expenses per Net KWh	0.0000			0.0232		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

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* (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
610.70			483.30			266.40			5
518			417			278			6
1977			6869			3415			7
0			0			0			8
533			415			270			9
0			0			0			10
48			22			27			11
280126000			2380281000			714837000			12
0			0			0			13
31659857			40984897			10886606			14
176513121			220387776			174805637			15
42315			226391			112544			16
208215293			261599064			185804787			17
340.9453			541.2768			697.4654			18
76228			474089			870979			19
16542485			129592845			56756276			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
1893582			1874572			998576			25
1851840			1794435			607498			26
175227			33681			70507			27
0			2160			432			28
843808			64686			81266			29
392118			37520			51237			30
0			0			0			31
2852934			6083380			9322261			32
202398			48074			14023			33
24830620			140005442			68773055			34
0.0886			0.0588			0.0962			35
Gas	Oil		Gas	Oil		Gas	Oil		36
Mcfs	Barrels		Mcfs	Barrels		Mcfs	Barrels		37
2736120	1297	0	16740333	0	0	5766920	0	0	38
1019000	138690	0	1019000	138690	0	1019000	138690	0	39
4.376	0.000	0.000	3.570	0.000	0.000	3.062	0.000	0.000	40
5.994	110.368	0.000	7.741	0.000	0.000	9.842	0.000	0.000	41
5.880	18.983	0.000	7.594	0.000	0.000	9.655	0.000	0.000	42
0.059	0.000	0.000	0.054	0.000	0.000	0.079	0.000	0.000	43
9961.300	0.000	0.000	7169.100	0.000	0.000	8225.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/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: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
									1
									2
									3
									4
		0.00			0.00			0.00	5
		0			0			0	6
		0			0			0	7
		0			0			0	8
		0			0			0	9
		0			0			0	10
		0			0			0	11
		0			0			0	12
		0			0			0	13
		0			0			0	14
		0			0			0	15
		0			0			0	16
		0			0			0	17
		0			0			0	18
		0			0			0	19
		0			0			0	20
		0			0			0	21
		0			0			0	22
		0			0			0	23
		0			0			0	24
		0			0			0	25
		0			0			0	26
		0			0			0	27
		0			0			0	28
		0			0			0	29
		0			0			0	30
		0			0			0	31
		0			0			0	32
		0			0			0	33
		0			0			0	34
		0.0000			0.0000			0.0000	35
									36
									37
0	0	0	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 (80% interest) and operator of the Boardman Plant. On December 31, 2013, PGE took on certain interests for the 15% ownership of BA Leasing LLC. Prior to this transaction, PGE's ownership was 65%. PGE filed an application with the FERC through Docket EC14-13-000 and received approval of the transaction December 19, 2013; the transaction was executed on 12/31/13. The other owners are Idaho Power Company (10%) and Power Resources Cooperative (10%).

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 80% share. Reported here are the respondent's share of the cost of plant, net generation and production expenses. Details are reported in Page 402, col (b).

Schedule Page: 403 Line No.: 9 Column: d

Based on January average temperature.

Schedule Page: 403 Line No.: 9 Column: e

Based on January average temperature.

Schedule Page: 403 Line No.: 9 Column: f

Based on January average temperature.

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

Jointly owned. 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.

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

The Boardman Coal Plant does not use oil for generation. Oil is used during startup or upset 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 useage. The Average BTU per KWh Net Generation reported is a composite heat rate for both fuels.

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

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

Schedule Page: 402 Line No.: 44 Column: f1

The Coyotes 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	46
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	45
12	Net Generation, Exclusive of Plant Use - Kwh	0	143,187,000
13	Cost of Plant		
14	Land and Land Rights	0	33,434
15	Structures and Improvements	0	6,482,115
16	Reservoirs, Dams, and Waterways	0	25,330,154
17	Equipment Costs	0	9,239,816
18	Roads, Railroads, and Bridges	0	1,976,298
19	Asset Retirement Costs	0	90
20	TOTAL cost (Total of 14 thru 19)	0	43,061,907
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	1,170.1605
22	Production Expenses		
23	Operation Supervision and Engineering	0	74,264
24	Water for Power	0	61,906
25	Hydraulic Expenses	0	628,672
26	Electric Expenses	0	174,510
27	Misc Hydraulic Power Generation Expenses	0	916,690
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	338,145
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	59,554
32	Maintenance of Electric Plant	0	455,365
33	Maintenance of Misc Hydraulic Plant	0	438,806
34	Total Production Expenses (total 23 thru 33)	0	3,147,912
35	Expenses per net KWh	0.0000	0.0220

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)	105	0
7	Plant Hours Connect to Load	7,374	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	406,438,000	270,972,000
13	Cost of Plant		
14	Land and Land Rights	3,672,025	2,448,139
15	Structures and Improvements	8,782,620	5,840,664
16	Reservoirs, Dams, and Waterways	15,517,913	10,568,375
17	Equipment Costs	9,706,339	6,501,629
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)	40,898,801	27,510,392
21	Cost per KW of Installed Capacity (line 20 / 5)	372.4845	375.8250
22	Production Expenses		
23	Operation Supervision and Engineering	226,779	151,755
24	Water for Power	155,705	87,717
25	Hydraulic Expenses	754,486	205,989
26	Electric Expenses	254,869	182,532
27	Misc Hydraulic Power Generation Expenses	500,457	278,784
28	Rents	26,475	5,163
29	Maintenance Supervision and Engineering	41,981	12,049
30	Maintenance of Structures	2,055	2,055
31	Maintenance of Reservoirs, Dams, and Waterways	14,586	14,586
32	Maintenance of Electric Plant	233,916	37,494
33	Maintenance of Misc Hydraulic Plant	159,838	84,065
34	Total Production Expenses (total 23 thru 33)	2,371,147	1,062,189
35	Expenses per net KWh	0.0058	0.0039

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	18.90	51.00	5
57	26	45	6
8,760	8,760	8,758	7
			8
58	25	44	9
7	4	19	10
0	0	7	11
176,750,000	95,982,000	196,792,000	12
			13
377,100	86,408	9,457	14
8,339,836	2,902,453	6,436,936	15
31,427,532	53,868,659	19,948,729	16
8,336,346	8,438,453	9,214,218	17
1,663,306	458,019	2,322,130	18
6	64	2,122	19
50,144,126	65,754,056	37,933,592	20
1,229.0227	3,479.0506	743.7959	21
			22
57,034	40,626	85,093	23
48,652	40,259	58,674	24
667,443	122,581	719,477	25
134,726	148,226	173,229	26
177,885	149,753	307,195	27
-50,144	0	498,966	28
29,176	24,590	103,875	29
0	0	21	30
30,715	12,809	218,035	31
23,696	125,150	37,006	32
104,412	116,657	142,577	33
1,223,595	780,651	2,344,148	34
0.0069	0.0081	0.0119	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 2013/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
277.20	184.80	15.40	5
290	0	18	6
7,789	0	8,749	7
			8
353	0	18	9
192	0	7	10
38	0	1	11
949,217,000	632,843,000	129,579,000	12
			13
3,726,481	2,521,011	572,077	14
14,922,571	9,842,623	9,437,850	15
166,670,815	109,083,602	23,382,190	16
23,869,377	15,956,055	13,795,894	17
2,124,580	1,471,793	0	18
165	165	2,629	19
211,313,989	138,875,249	47,190,640	20
762.3160	751.4894	3,064.3273	21
			22
273,432	181,736	28,138	23
297,593	214,497	33,336	24
2,902,528	2,232,142	82,769	25
227,426	139,014	128,574	26
977,514	706,579	154,001	27
115,620	89,572	0	28
156,737	120,153	37,546	29
6,123	6,123	36,109	30
101,837	101,837	124,346	31
953,328	713,258	175,275	32
345,362	252,751	61,640	33
6,357,500	4,757,662	861,734	34
0.0067	0.0075	0.0067	35

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

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

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

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

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

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

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

Jointly owned. Installed capacity on line 5 represents 66.67% share. Details reported on Page 407.1, column (d). Reported here are respondent's 66.67% share of cost of plant, net generation and production expenses.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/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 2013/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
			1
			2
			3
			4
			5
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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 2013/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	5	104,631
2	Oregon Military Dept/A.F.R.C	2001	1.60	1.6	29	164,147
3	US Bank Corp Columbia Center	2001	6.40	6.2	713	488,058
4	Providence Business Center	2004	2.00	1.8		385,944
5	Portland State University	2004	2.80	2.8	47	261,732
6	Oregon Military Joint Forces HQ	2005	1.60	1.6	10	191,439
7	Stimson Lumber	2005	0.57	0.5	8	159,546
8	FORTIX (ViaWest)	2005	1.00	0.9	21	515,393
9	Skyline	2005	2.00	1.8	40	201,526
10	Tri-Quint	2005	0.60	0.5	7	109,968
11	NCCWC- Filter Plant	2005	2.00	1.8	31	122,958
12	PCC Structurals	2005	1.00	0.9	12	113,874
13	Providence Portland Medical Center	2005	6.00	5.4	243	256,701
14	Salem Hospital	2006	4.00	3.6	170	188,494
15	Sunrise Water Authority Pump Station	2006	1.25	1.1	8	88,272
16	Providence Newberg Hospital	2006	1.50	1.4	42	156,833
17	Sungard DSG	2006	2.00	1.8	37	331,845
18	Kaiser Sunnyside Hospital	2007	4.50	4.0	124	352,752
19	Newberg Waste Water Treatment Plant	2008	2.00	1.8	30	154,458
20	Xerox Corp	2007	4.00	3.6	65	380,259
21	Newberg Water Treatment Plant	2007	1.00	0.9	15	78,159
22	MEMC (Solaicx)	2008	1.00	0.9	13	62,963
23	Solar World	2008	3.00	2.7	36	219,984
24	Oregon Dept of Admin Serv - Data Center	2010	2.00	1.8	63	277,254
25	Sanyo	2010	1.00	0.9	6	43,144
26	Sysco Foods	2010	2.00	1.8	34	184,781
27	Clackamas Intertie 2	2012	0.60	0.5	7	134,549
28	Dawson Creek	2012	0.80	0.7	12	95,706
29	Kaiser Westside Hospital	2012	4.00	3.6	189	402,780
30	North Plains Pump Station	2012	0.80	0.7	11	53,132
31	Oak Lodge Sanitary District	2012	2.00	1.8	27	229,144
32	Oregon Dept of Admin Serv - Revenue Bldg	2012	1.50	1.4	19	284,255
33	Oregon State Hospital	2012	4.00	3.6	91	172,879
34	Portland Service Center	2012	0.50	0.5	8	322,698
35	Sandy Highschool	2012	1.25	1.1	19	179,858
36	TATA Communications - Hillsboro	2012	4.50	3.3	69	328,963
37	Tri-City Wastewater Treatment Plant	2012	2.50	2.3	38	161,695
38	TATA Communications - Portland	2013	6.60	6.0	137	560,380
39	City of Hillsboro Crandall Reservoir	2013	0.80	0.7		102,561
40	East County Courts	2013	1.50	1.4	7	
41	City of Portland-Columbia Blvd WWTP	2013	1.00	0.9	3	
42	Food Services of America	2013	2.00	1.8	11	
43	Total					8,623,715
44						
45						
46						

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
209,263		4,344	7,356	diesel-low s	2,376	1
102,592		9,969	13,512	diesel-low s	2,386	2
76,259		71,579	66,333	diesel-low s	2,168	3
192,972				diesel-low s	2,293	4
93,476			22,542	diesel-low s	2,643	5
119,650		5,323	42,792	diesel-low s	2,389	6
282,382		5,414	12,912	diesel-low s	2,367	7
515,393		24,726	75,991	diesel-low s	2,336	8
100,763		3,746	38,075	diesel-low s	2,389	9
183,279		1,528	8,106	diesel-low s	2,337	10
61,479		7,486	15,597	diesel-low s	2,389	11
113,874		5,915	8,605	diesel-low s	2,435	12
42,784			33,640	diesel-low s	2,571	13
47,124		25,633	100,253	diesel-low s	2,389	14
70,617		6,317	43,497	diesel-low s	2,389	15
104,555			21,375	diesel-low s	2,643	16
165,922		11,533	24,805	diesel-low s	2,433	17
78,389		37,850	27,038	diesel-low s	2,389	18
77,229		3,002	14,547	diesel-low s	2,389	19
95,065		19,737	34,274	diesel-low s	2,418	20
78,159		7,314	9,675	diesel-low s	2,389	21
62,963		2,366	16,434	diesel-low s	2,389	22
73,328		6,448	46,902	diesel-low s	2,337	23
138,627		4,596	36,428	diesel-low s	2,389	24
43,144			47,590	diesel-low s	2,714	25
92,391		11,196	10,443	diesel-low s	2,389	26
224,248		1,817	53	diesel-low s	2,471	27
119,632			6,471	diesel-low s	2,286	28
100,695		39,235	10,040	diesel-low s	2,389	29
66,415			7,191	diesel-low s	2,618	30
114,572		10,246	10,430	diesel-low s	2,478	31
189,503		6,308	14,234	diesel-low s	2,389	32
43,220			19,472	diesel-low s	2,336	33
645,396			4,780	diesel-low s	2,336	34
143,887		5,200	8,824	diesel-low s	2,337	35
73,103			28,009	diesel-low s	2,336	36
64,678		7,713	9,331	diesel-low s	2,337	37
84,906			101,153	diesel-low s	2,336	38
128,201			871	diesel-low s		39
			10,318	diesel-low s	2,336	40
			10,208	diesel-low s	2,336	41
			1,392	diesel-low s	2,336	42
		346,541	1,027,499			43
						44
						45
						46

Schedule Page: 410 Line No.: 40 Column: f

The capital balance $314,202 for East County Courts DSG was classified to non-production accounts incorrectly and therefore is not recorded as production on line 40. These costs will be reclassified to the proper capital production account in 2014.

Schedule Page: 410 Line No.: 41 Column: f

The capital balance $160,105 for City of Portland - Columbia Blvd Wastewater Treatment Plant DSG was classified to non-production accounts incorrectly and therefore is not recorded as production on line 41. These costs will be reclassified to the proper capital production account in 2014.

Schedule Page: 410 Line No.: 42 Column: f

The capital balance $197,355 for Food Services of America DSG was classified to non-production accounts incorrectly and therefore is not recorded as production on line 42. These costs will be reclassified to the proper capital production account in 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 2013/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	PELTON 230KV PROJECT							
19	PELTON	ROUND BUTTE	230.00	230.00	H-WOOD	7.87		1
20								
21	NON PROJECT 230KV:							
22	BETHEL	ROUND BUTTE	230.00	230.00	H-WOOD	55.19		1
23			230.00	230.00	ST. TOWER	44.85		1
24	ROUND BUTTE	BPA REDMOND	230.00	230.00	H-WOOD	23.58		1
25	BETHEL	BPA TIE (SANTIAM)	230.00	230.00	H-WOOD	3.64		1
26	BETHEL	McLOUGHLIN	230.00	230.00	H-WOOD	35.57		1
27	CARVER	GRESHAM	230.00	230.00	H-WOOD	7.17		1
28	McLOUGHLIN	CARVER	230.00	230.00	H-WOOD	4.95		1
29	McLOUGHLIN	CARVER	230.00	230.00	ST. MONOP	4.88		1
30	BPA KEELER	ST. MARY'S W.	230.00	230.00	H-WOOD	2.89		1
31			230.00	230.00	ST. TOWER	3.78		2
32	BLUE LAKE	TROUTDALE BPA	230.00	230.00	H-WOOD	0.84		1
33			230.00	230.00	ST. MONOP	0.58		1
34	PEARL BPA	SHERWOOD	230.00	230.00	ST. TOWER		4.72	2
35			230.00	230.00	ST. TOWER	0.16		1
36					TOTAL	592.17	536.65	60

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 2013/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	GRESHAM	LINNEMAN	230.00	230.00	ST. TOWER	0.31		1
2	McLOUGHLIN	SHERWOOD	230.00	230.00	ST. TOWER	11.51		1
3			230.00	230.00	H-TOWER	0.60		1
4	NON PROJECT 230KV							
5	McLOUGHLIN	SHERWOOD	230.00	230.00	ST. TOWER		4.40	2
6	ST. MARY'S W.	MURRAYHILL	230.00	230.00	ST. TOWER	5.92		1
7	HORIZON	KEELER BPA	230.00	230.00	ST. MONOP	1.47		1
8	MURRAYHILL	SHERWOOD	230.00	230.00	ST. TOWER	5.68		2
9	PORT WESTWARD	TROJAN	230.00	230.00	ST. MONOP	18.78		1
10			230.00	230.00	ST. MONOP	9.39		1
11	TROJAN	ST. MARY'S W.	230.00	230.00	H-WOOD	0.10		1
12			230.00	230.00	ST. TOWER	3.86		2
13			230.00	230.00	ST. TOWER	4.80		1
14			230.00	230.00	ST. TOWER	32.68		2
15	TROJAN	RIVERGATE	230.00	230.00	ST. TOWER		32.20	2
16			230.00	230.00	ST. TOWER	2.88		2
17	Tot Nonproj 230kv Costs							
18	GRESHAM	TROUTDALE BPA	230.00	230.00	ST. TOWER		0.43	1
19	BOARDMAN	PPL DALREED	230.00	230.00	H-WOOD	16.76		1
20	Tot 230KV LINE EXPENSES							
21								
22	PROJECT 115 KV LINES							
23	FARADAY	MCLOUGHLIN	115.00	115.00	H-WOOD	14.70		1
24	NORTH FORK	FARADAY	115.00	115.00	H-WOOD	2.79		1
25	OAK GROVE	FARADAY	115.00	115.00	DC LATTICE	18.68		2
26	OAK GROVE	MCLOUGHLIN	115.00	115.00	H-WOOD	14.70		2
27			115.00	115.00	DC LATTICE	18.68		2
28	Tot 115KV LINE EXPENSES							
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	592.17	536.65	60

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 2013/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	15,581,384	15,856,811					3
		148,889	148,889					4
		148,889	148,889					5
	5,904		5,904					6
1480MCMACSR		4,620,708	4,620,708					7
		3,624,934	3,624,934					8
								9
								10
								11
								12
								13
	1,194,326	43,101,062	44,295,388					14
				1,570,435	638,589	844,166	3,053,190	15
								16
		3,040,852	3,040,852					17
								18
795MCMACSR	7,579	298,654	306,233					19
								20
								21
1272MCMACSR								22
1272MCMACSR								23
795MCMACSR								24
795MCMACSR								25
1272MCMACSR								26
1272MCMAAC								27
1272MCMAAC								28
1272MCMACSS								29
1590MCMACSRTW								30
1590MCMACSRTW								31
1780MCMACSR								32
								33
2388MCMAACTW								34
2388MCMAACTW								35
	10,551,761	142,001,021	152,552,782	2,061,412	838,235	1,073,104	3,972,751	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 2013/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.
1272MCMAAC								1
1272MCMAAC								2
1780MCMACSR								3
								4
1272MCMAAC								5
1272MCMAAC								6
1272MCMACSS								7
1272MCMAAC								8
2156MCMACSS								9
2156MCMACSS								10
1272MCMAAC								11
1272MCMAAC								12
1590MCMAAC								13
1590MCMAAC								14
1590MCMAAC								15
1272MCMACSR								16
	8,862,552	65,833,693	74,696,245					17
954KCMACSR								18
795KCMAAC		1,074,346	1,074,346					19
				489,793	199,165	155,116	844,074	20
								21
								22
795KCMACSR		871,841	871,841					23
556KCMACSR	120,248	621,351	741,599					24
250CU	12,477	503,937	516,414					25
795KCMACSR								26
250CU	22,295	884,661	906,956					27
				1,184	481	73,822	75,487	28
								29
								30
								31
								32
								33
								34
								35
	10,551,761	142,001,021	152,552,782	2,061,412	838,235	1,073,104	3,972,751	36

Schedule Page: 422 Line No.: 4 Column: a

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

Schedule Page: 422 Line No.: 5 Column: a

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

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

Jointly owned with Idaho Power Company and Power Resources Cooperative. 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.: 19 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 Line No.: 34 Column: a

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

Schedule Page: 422.1 Line No.: 18 Column: a

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

Schedule Page: 422.1 Line No.: 19 Column: a

Jointly owned with Idaho Power Company and Power Resources Cooperative. 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 2013/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)	(c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	No additions in 2013						
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
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35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL						

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	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.
									1
									2
									3
									4
									5
									6
									7
									8
									9
									10
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/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	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 2013/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	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 2013/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	

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Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	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	38.00	
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	13.00
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	

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SUBSTATIONS

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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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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	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	Round Butte, near Madras, OR	Transm./unattended	230.00	66.00	12.50
14	Sand Springs, 22 mi E/22 mi S of Bend, OR	Transm./unattended	500.00		
15	Sherwood, near Six Corners, OR	Transm./unattended	230.00	115.00	13.00
16	Slatt, BPA, Arlington, OR	Transm./unattended	500.00		
17	St. Marys, West Yard, near Beaverton, OR	Transm./unattended	230.00	115.00	13.00
18	Sullivan, West Linn, OR	Transm./Unattended	57.00	4.15	
19	Sycan, 27 mi S of Silver Lake, OR	Transm./unattended	500.00		
20	Trojan, near Rainier, OR	Transm./unattended	230.00	12.50	
21					
22	TOTAL MVa		28853.00	5012.03	392.30
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Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
69	11		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
56	2		Capacitor Banks			9
56	2		Capacitor Banks	5	15,000	10
50	2		Capacitor Banks	2	7,200	11
24	2		Capacitor Banks	1	12,150	12
28	1		Capacitor Banks	2	6,000	13
39	4		Capacitor Banks	2	3,600	14
250	6					15
200	4		Capacitor Banks	8	28,800	16
56	2		Capacitor Banks	4	13,200	17
39	2		Capacitor Banks	2	7,200	18
						19
						20
41	2		Capacitor Banks	4	13,200	21
28	1		Capacitor Banks	2	6,000	22
28	1		Capacitor Banks	2	6,000	23
140	1					24
28	1		Capacitor Banks	2	6,000	25
28	1		Capacitor Banks	2	6,000	26
28	1		Capacitor Banks	2	6,000	27
17	1		Capacitor Banks	2	6,000	28
125	1					29
22	2		Capacitor Banks	4	6,000	30
22	1					31
56	2		Capacitor Banks	2	6,000	32
13	1		Capacitor Banks	3	9,000	33
14	1		Capacitor Banks	2	3,000	34
56	2		Capacitor Banks	4	12,600	35
140	2		Capacitor Banks	3	21,600	36
63	3		Capacitor Banks	1	8,400	37
63	3		Capacitor Banks	1	24,000	38
70	1		Capacitor Banks	2	31,200	39
14	1					40

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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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.
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		Capacitor Banks	4	7,200	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

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SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
34	2		Capacitor Banks	3	6,600	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 2013/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
50	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
6	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

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
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
372	3	2				12
22	1					13
			Series Capacitor	1	546,000	14
640	2					15
						16
960	3		Capacitor Banks	3	108,000	17
33	1					18
			Series Capacitor	1	546,000	19
56	2					20
						21
17770	359	4		408	3,438,104	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 35300.

Schedule Page: 426.4 Line No.: 16 Column: a
Jointly owned with Idaho Power Company and Power Resources Cooperative. PGE has an 80% 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 and Power Resources Cooperative. PGE has an 80% 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 and Power Resources Cooperative. PGE has an 80% 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 20% 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 35300.

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 20% 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 35300.
Contribution in aid of construction made to Bonneville Power Administration in 1995 in the amount of 1,115,709 to FERC account 35300.

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 35300.

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

Jointly owned with the Confederated Tribes of the Warm Springs Reservation of Oregon. PGE has a 66.67% share of the jointly owned capacity, 100% of the capacity is reported.

Schedule Page: 426.5 Line No.: 14 Column: a

Line compensation only.

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

Owned and operated by Bonneville Power Administration. Contribution in aid of construction made to BPA recorded to FERC account 35300.

Schedule Page: 426.5 Line No.: 19 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 2013/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	871,641
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	783,857
23				
24				
25				
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Schedule	Page No.