RE 54 e-FILING REPORT COVER SHEET

REPORT NAME: **PGE Annual Reports for the year ending December 31, 2013**

COMPANY NAME: **Portland General Electric Company**

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☒ No

If known, please select designation: ☒ RE (Electric

Report is required by: ☒ OAR 860-027-0070 (1) and (2) Annual Reports

☐ Statute

Is this report associated with a specific docket/case? ☒ No

Key words: Report 54 A FERC Form 1 (2013)

Report 54 B Oregon Supplement to FERC Form 1 (2013)

Report 54 C Annual Report to Shareholders (2013)

OAR 860-027-0070

If known, please select the PUC Section to which the report should be directed:

☒ **Electric and Natural Gas Revenue Requirements**

☐ Electric Rates and Planning

☐ Utility Safety, Reliability & Security

☐ Administrative Hearings Division

THIS FILING IS		
Item 1: ☒ 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

Name of Respondent	This Report 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)
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		

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

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.

Name of Respondent	This Report 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

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	
17				
18	SunWay 3, LLC	Solar power generation	0.01	
19				
20				
21				
22				
23				
24				
25				
26				
27				

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: 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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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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FOOTNOTE DATA

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

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

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

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	John W. Ballantine	Palm Beach, Florida
2	Private Investor, Retired from First Chicago NBD Corp.	
3	Rodney L. Brown, Jr.	Seattle, Washington
4	Managing Partner, Cascadia Law Group PLLC	
5	Jack E. Davis	Phoenix, Arizona
6	Chair of the Board of Portland General Electric Company	
7	Retired Chief Executive Officer of	
8	Arizona Public Service Company	
9	David A. Dietzler	Lake Oswego, Oregon
10	Retired Partner of KPMG LLP	
11	Kirby A. Dyess	Beaverton, Oregon
12	Principal, Austin Capital Management LLC	
13	Mark B. Ganz	Portland, Oregon
14	President and Chief Executive Officer of	
15	Cambia Health Solutions (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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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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FOOTNOTE DATA

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.

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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
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INFORMATION ON FORMULA RATES
Formula Rate Variances

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

Line No.	Page No(s).	Schedule	Column	Line No
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Name of Respondent	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.

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IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

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

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IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

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:

<u>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</u>, 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.

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IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

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

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IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

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.

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IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

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

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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

Name of Respondent	This Report 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)(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	This Report 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 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

Name of Respondent	This Report 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 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		

Name of Respondent	This Report 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)
	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)

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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)
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
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STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
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

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 2013/Q4

FOOTNOTE DATA

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.

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

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.

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Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2013/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

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.

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NOTES TO FINANCIAL STATEMENTS (Continued)

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.

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NOTES TO FINANCIAL STATEMENTS (Continued)			

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

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NOTES TO FINANCIAL STATEMENTS (Continued)

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.

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NOTES TO FINANCIAL STATEMENTS (Continued)

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.

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NOTES TO FINANCIAL STATEMENTS (Continued)

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.

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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

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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

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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

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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.

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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.

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	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.

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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.

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

Commodity Contracts	Fair Value 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

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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,

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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

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PGE's net volumes related to its Assets and Liabilities from price risk management activities resulting from its derivative transactions, which are expected to deliver or settle at various dates through 2035, were as follows (in millions):

	As of December 31,					
	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: Derivatives	Gross Amounts Not Offset in Balance Sheets: Cash Collateral(1)	Net Amount
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.

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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.

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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.

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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.

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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.

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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.

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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.

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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.

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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.

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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.

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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.

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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.

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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

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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%

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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

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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

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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.

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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.

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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%

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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

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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		Contract Expiration	PGE Cost, including Debt Service	
		Output	Capacity		2013	2012
			(in MW)			
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.

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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.

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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.

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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

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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.

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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

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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.

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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)

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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]

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FOOTNOTE DATA

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

Comprised of the net amount of the actuarial valuation of $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.

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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

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
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					14
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FOOTNOTE DATA

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.

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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)		

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NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
			2
			3
			4
			5
			6
			7
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			11
			12
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			19
			20
			21
			22

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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

Name of Respondent	This Report 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) (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

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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) (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

Name of Respondent	This Report 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) (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

Name of Respondent	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: 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					
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39					
40					
41					
42					
43					
44					
45					
46					
47	TOTAL				

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

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Damascus, Clackamas County, OR	2007	Future	543,591
3	Sewell, Washington County, OR	2008	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				
34				
35				
36				
37				
38				
39				
40				
41				
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

Name of Respondent	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: 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.

Name of Respondent	This Report 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 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		

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: 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.

Name of Respondent	This Report 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)

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

Name of Respondent	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: 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	

Name of Respondent	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: 227 Line No.: 11 Column: d

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 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.	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. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
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				

Name of Respondent	This Report 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)	
								1
								2
								3
								4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Name of Respondent 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

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

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

Name of Respondent	This Report 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

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	

Name of Respondent	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: 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					

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: 231 Line No.: 29 Column: b

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

Name of Respondent	This Report 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 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	This Report 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 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

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

Name of Respondent	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: 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

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FOOTNOTE DATA

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.

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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						
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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

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Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2013/Q4

FOOTNOTE DATA

Schedule Page: 234   Line No.: 1   Column:

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

CAPITAL STOCKS (Account 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Account 201:			
2	Common Stock	160,000,000		
3				
4	Total_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				
11				
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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

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
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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		
24		
25		
26		
27		
28		
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39		
40	TOTAL	16,366,513

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Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2013/Q4

FOOTNOTE DATA

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.

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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		
7		
8		
9		
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21		
22	TOTAL	10,832,643

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.

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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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32			
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) (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

Name of Respondent	This Report 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) (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
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						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		
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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	/ /	2013/Q4

FOOTNOTE DATA

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)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year	Taxes Paid During Year	Adjust-ments
		Taxes Accrued (Account 236)	Prepaid Taxes (Include in Account 165)			
	(a)	(b)	(c)	(d)	(e)	(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 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

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	This Report 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)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%						
6							
7							
8	TOTAL						
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (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
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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 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						
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17						
18						
19						
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47	TOTAL	1,596,555		58,038	9,470,515	11,009,032

Name of Respondent	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: 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

Name of Respondent	This Report 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) (Continued)

3. Use footnotes as required.

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

NOTES (Continued)

Name of Respondent	This Report 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	Balance at Beginning of Year	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1	Amounts Credited to Account 411.1
	(a)	(b)	(c)	(d)
1	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

Name of Respondent	This Report 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 - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
		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

Name of Respondent	This Report 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 - 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)

Name of Respondent	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: 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	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	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	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	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

Name of Respondent	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: 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	This Report 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)

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

Name of Respondent	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

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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11					
12					
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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

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

SALES OF ELECTRICITY BY RATE SCHEDULES

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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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35						
36						
37						
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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

Name of Respondent	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: 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

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Portland General Electric Company	(1) X An Original (2) _ A Resubmission	/ /	2013/Q4

FOOTNOTE DATA

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**

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SALES FOR RESALE (Account 447)

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Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	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**

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					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**

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3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes 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	Actual Demand (MW) 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	This Report 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	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**

Name of Respondent	This Report 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	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**

Name of Respondent	This Report 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.
					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**	

Name of Respondent	This Report 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.
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**	

Name of Respondent	This Report 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.
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**	

Name of Respondent	This Report 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.
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**	

Name of Respondent	This Report 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.
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**	

Name of Respondent	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: 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

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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)
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

Name of Respondent	This Report 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)
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

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 2013/Q4

FOOTNOTE DATA

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 Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	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.

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	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	This Report 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 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					

Name of Respondent	This Report 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)	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	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.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	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)

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.

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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	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)

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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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)	Average Monthly CP Demand (f)
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)

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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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	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					

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
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	This Report 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.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
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	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	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.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
				-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.

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
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.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received	MegaWatt Hours Delivered	Demand Charges ($)	Energy Charges ($)	Other Charges ($)	Total (j+k+l) of Settlement ($)	
(g)	(h)	(i)	(j)	(k)	(l)	(m)	
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.

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
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	

Name of Respondent	This Report 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.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
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)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		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	

Name of Respondent	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: 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

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 2013/Q4

FOOTNOTE DATA

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 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 Classification (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	This Report 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	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 Classifi-cation (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	This Report 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	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**	

Name of Respondent	This Report 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.
				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	This Report 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.
	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**	

Name of Respondent	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: 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.

Name of Respondent	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: 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.

Name of Respondent	This Report 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 ISO/RTOs

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

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 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)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Avista Corp	NF	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

Name of Respondent	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: 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		
16		
17		
18		
19		
20		
21		
22		
23		
24		
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44		
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

Name of Respondent	This Report 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 (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							
21							
22							
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26							
27							
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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

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		
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26	Totals	
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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

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

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

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
					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
					17
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					24
					25
646,154	90,115		736,269		26
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 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			

Name of Respondent	This Report 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

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	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				
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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

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

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)				
7					
8					
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39					
40					
41					
42					
43					
44					
45					
46	TOTAL	6,920,279	8,363,832	6,840,408	28,471,654

Name of Respondent	This Report 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

PURCHASES AND SALES OF ANCILLARY SERVICES

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

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

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

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

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

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

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

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

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	46,284	MW	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

Name of Respondent	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: 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.

Name of Respondent	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: 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			

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Portland General Electric Company	(1) X An Original (2) __ A Resubmission	/ /	2013/Q4

FOOTNOTE DATA

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)

Name of Respondent	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: 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)

Name of Respondent	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: 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

Name of Respondent	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

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

Name of Respondent	This Report 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 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)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	17,673,447
3	Steam	4,069,602			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	
5	Hydro-Conventional	1,646,105			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	3,553,416
7	Other	4,575,191			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	10,290,898	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	25,695
10	Purchases	12,159,558	27	Total Energy Losses	1,698,435
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	22,950,993
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			

Name of Respondent	This Report 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

Name of Respondent	This Report 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)*

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

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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

(d)			(e)			(f)			Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Schedule Page: 402 Line No.: -1 Column: b

Respondent is the principal owner (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.

Name of Respondent	This Report 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)

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

Name of Respondent	This Report 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)

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

Name of Respondent	This Report 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. 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

Name of Respondent	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: 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
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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

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						

Name of Respondent	This Report 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

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	This Report 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	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		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(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

Name of Respondent	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: 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	This Report 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 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							
12							
13							
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39							
40							
41							
42							
43							
44	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 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
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									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

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	

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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

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

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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	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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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	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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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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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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SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
69	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

Name of Respondent	This Report 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 (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)	
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

Name of Respondent	This Report 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 (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	This Report 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 (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

Name of Respondent	This Report 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 (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
84	3		Capacitor Banks	6	18,000	1
42	2		Capacitor Banks	4	13,200	2
15	2		Capacitor Banks	1	1,800	3
						4
						5
						6
						7
464	4					8
170	1					9
502	2					10
140	1					11
28	1		Capacitor Banks	2	6,000	12
480	3					13
320	1					14
28	1		Capacitor Banks	2	6,000	15
685	3					16
55	1					17
55	1					18
80	3					19
						20
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

Name of Respondent	This Report 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 (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

Name of Respondent	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: 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

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

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				
26				
27				
28				
29				
30				
31				
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ANNUAL REPORT
OREGON SUPPLEMENT TO FERC FORM 1
For Year Ended December 31, 2013

PORTLAND GENERAL ELECTRIC COMPANY
121 SW Salmon Street
Portland, Oregon

ANNUAL REPORT

OREGON SUPPLEMENT TO FERC FORM 1
for
MULTI-STATE ELECTRIC COMPANIES

INDEX

Note: Only Schedules 14, 15 and 41 through 46 are included. For information on other Schedules refer to the appropriate FERC Form 1 Schedule.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PORTLAND GENERAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 2013

CALCULATION OF CURRENT FEDERAL INCOME TAX EXPENSE - Account 409.1

1. Report amounts used to derive current Federal income tax expense, Account 409.1, for the reporting period. If amounts are shown in thousands, show (000) in the heading for column (b).

2. Show amounts increasing taxable income as positive values and amounts decreasing taxable income as negative.

3. Current tax expense on this schedule must match the amount reported on page 1, line 12 of this report. Separately identify adjustments arising from revisions of prior year accruals.

4. Minor amounts of other additions (subtractions) may be grouped.

Line No.	Particulars (Details)	Amount (b)
1	**Electric Operating Revenues**	1,845,416,891
2	**Operations & Maintenance Expenses**	(1,232,425,235)
3	**Taxes, Other Than Income**	(102,358,656)
4	**Utility Depreciation, Amortization, Regulatory Expenses**	(235,246,279)
5	**Interest**	(100,818,804)
6	**State Income (Excise) Tax**	(4,306,119)
7	**Federal Income Tax Depreciation in Excess of Book Depreciation**	(57,809,690)
8	**Other Additions (Subtractions) to Derive Taxable Income**	
9		
10	**Other:**	
11	Taxable Income Not Reported on Books - See Note 1, Pg 14a	0
12	Deductions Recorded on Books Not Deducted For Tax - See Note 2, Pg 14a	85,889,952
13	Income Recorded on Books Not Included in Return - See Note 3, Pg 14a	(7,513,832)
14	Deductions on Return Not Charged Against Books - See Note 4, Pg 14a	(17,358,283)
15	**Total Other Additions (Subtractions) to Derive Taxable Income**	**61,017,837**
16		
17		
18		
19		
20		
21		
22		
23	**Federal Tax Net Income (Loss) Before NOL**	**173,469,945**
24	**Federal NOL Carryforward Adjustment**	
25	**Federal Tax Net Income (Loss) After NOL**	**173,469,945**
26	**Computation of Tax:**	
27	Federal Taxable Income X 35%	60,714,481
28	Federal Energy Tax Credit	(32,157,255)
29	RTA and FAS 109 Adjustment	(957,696)
30		
31		
32		
33	**TOTAL CURRENT FEDERAL INCOME TAX - (Calculated)**	**27,599,530**
34	**TOTAL CURRENT FEDRAL INCOME TAX - FERC 409.1**	**27,599,530**

STATE OF OREGON - ALLOCATED

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PORTLAND GENERAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 2013

CALCULATION OF CURRENT FEDERAL INCOME TAX EXPENSE - Account 409.1

Note 1:		0
	Total - Taxable Income Not Reported on Books	0
Note 2:		
	Employee Benefits	8,925,780
	Regulatory Debits	25,161,062
	Qualified NDT	47,657,084
	Total Other	4,146,026
	Total - Deductions Recorded on Books Not Deducted For Tax	85,889,952
Note 3:		
	Regulatory Credits	(6,626,881)
	State Local RTA	(886,951)
	Total - Income Recorded on Books Not Included in Return	(7,513,832)
Note 4:		
	Price Risk Management	(17,358,283)
	Total - Deductions on Return Not charged Against Book	(17,358,283)

STATE OF OREGON - ALLOCATED

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PORTLAND GENERAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 2013

CALCULATION OF CURRENT STATE INCOME (EXCISE) TAX EXPENSE - Account 409.1(Other)

1. Report amounts used to derive current Federal income tax expense, Account 409.1, for the reporting period. If amounts are shown in thousands, show (000) in the heading for column (b).
2. Show amounts increasing taxable income as positive values and amounts decreasing taxable income as negative.
3. Current tax expense on this schedule must match the amount reported on page 1, line 12 of this report. Separately identify adjustments arising from revisions of prior year accruals.
4. Minor amounts of other additions (subtractions) may be grouped.

Line No.	Particulars (Details)	Amount (b)
1	**Electric Operating Revenues**	1,845,416,891
2	**Operations & Maintenance Expenses**	(1,232,425,235)
3	**Taxes, Other Than Income**	(102,358,656)
4	**Utility Depreciation, Amortization, Regulatory Expenses**	(235,246,279)
5	**Interest**	(100,818,804)
6	**State Income (Excise) Tax Depreciation in Excess of Book Depreciation**	(68,462,338)
7	**Other Additions (Subtractions) to Derive Taxable Income**	.
8		
9	**Other:**	
10	Taxable Income Not Reported on Books - See note 1, Pg 15a	0
11	Deductions Recorded on Books Not Deducted For Tax - See Note 2, Pg 15a	89,379,488
12	Income Recorded on Books Not Included in Return - See Note 3, Pg 15a	(6,626,881)
13	Deductions on Return Not Charged Against Books - See Note 4, Pg 15a	(17,358,283)
14	**Total Other Additions (Subtractions) to Derive Taxable Income**	**65,394,324**
15		
16		
17	**State Tax Net Income**	**171,499,903**
18	**Computation of Tax:**	
19	Unapportioned Income (Loss)	171,499,903
20	Apportionment Ratio	91.09%
21	Oregon Taxable Income (Loss)	156,220,591
22	Less: Local Tax Deduction after apportionment	(900,306)
23	Nonbusiness income allocated entirely to OR	1,199,848
24	Oregon Taxable Income (Loss) After NOL and post-apportionment deductions	156,520,133
25	Oregon Tax Rate	7.6%
26	Oregon Excise Tax	11,895,530
27	Oregon Minimum Tax	
28	Oregon RTA and other adjustments	(508,278)
29	PTC & BETC	(8,107,107)
30		
31		
32		
33	**OREGON CURRENT UTILITY EXCISE TAX**	**3,280,145**
34	**MONTANA CURRENT UTILITY INCOME TAX**	**166,575**
35	**MULTNOMAH COUNTY & CITY OF PORTLAND CURRENT UTILITY INCOME TAX**	**859,399**
36	**TOTAL CURRENT STATE & LOCAL INCOME TAX - Computed**	**4,306,119**
37	**TOTAL CURRENT STATE & LOCAL INCOME TAX - FERC 409.1 (Other)**	**4,306,119**

STATE OF OREGON - ALLOCATED

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PORTLAND GENERAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission		Dec. 31, 2013

CALCULATION OF CURRENT STATE & LOCAL INCOME (EXCISE) TAX EXPENSE - Account 409.1

Note 1:		
	Total - Taxable Income Not Reported on Books	0
Note 2:		
	Employee Benefits	8,925,780
	Regulatory Debits	25,161,062
	Qualified NDT	47,657,084
	Total Other	7,635,562
	Total - Deductions Recorded on Books Not Deducted For Tax	89,379,488
Note 3:		
	Regulatory Credits	(6,626,881)
	Total - Income Recorded on Books Not Included in Return	(6,626,881)
Note 4:		
	Price Risk Management	(17,358,283)
	Total - Deductions on Return Not charged Against Book	(17,358,283)

POLITICAL ADVERTISING

Year: 2013

INSTRUCTIONS: List all payments for advertising, the purpose of which is to aid or defeat any measure before the people or to promote or prevent the enactment of any national, state, district or municipal legislation. Give the specific purpose of such advertising, when and where placed, and the account or accounts charged. Report whole dollars only. Provide a total for each account and a grand total.

Description	Account Charged	Amount
None		
Total		$ -

POLITICAL CONTRIBUTIONS

INSTRUCTIONS: List all payments for contributions to persons and organizations for the purpose of aiding or defeating any measure before the people or to promote or prevent the enactment of an national, state, district or municipal legislation. The purpose of all contributions or payments should be clearly explained. Report whole dollars only. Provide a total for each account and a grand total.

Description	Account Charged	2013 Amount
Citizens for Schools-Gresham-Barlow school	426.4	6,000
Citizens for Schools-Hillsboro	426.4	7,000
Clatskanie rural protection disctrict levy support	426.4	1,000
Committee for Safe and Successful Children Campaign	426.4	10,000
Edison Electric Institute	426.4	122,994
Grow Oregon Campaign	426.4	3,000
Hillsboro Chamber of Commerce PAC Contribution	426.4	2,000
Keep Prisoners in Jail Campaign	426.4	1,000
Oregon Unity for Marriage equality campaign	426.4	25,000
PGE Employee Candidate Assistance Fund	426.4	145,000
Portland Business Alliance PAC	426.4	2,500
Renew Columbia 9-1-1 Campaign	426.4	1,000
Restore Our Natural Areas Contribution - Portland PAC	426.4	5,000
Yes for Beaverton Schools	426.4	17,500
TOTAL ITEMS UNDER $1,000	426.4	1,359
TOTAL 2013 POLITICAL CONTRIBUTIONS		$ 350,353

EXPENDITURES TO ANY PERSON OR ORGANIZATION HAVING AN AFFILIATED INTEREST FOR SERVICES, ETC.

INSTRUCTIONS: Report all expenditures to any person or organization having an affiliated interest for service, advice, auditing, associating, sponsoring, engineering, managing, operating, financial, legal or other services. See Oregon Revised Statute 757.015 for definition of "affiliated interest." Give reference if such expenditures have in the past been approved by the Commission. Describe the services received and the account or accounts charged. Report whole dollars only.

Description	Account Charged	Total Amount	Amount Assigned to Oregon
The required affiliated interest expenditure information for 2013 will be provided in PGE's June 1, 2014 annual "Affiliated Interest Report".			

DONATIONS AND MEMBERSHIPS

INSTRUCTIONS: List all donations and membership expenditures made by the utility during the year and the accounts charged. Give the name, city, and state of each organization to whom a donation has been made. Group donations under headings such as:

1. Contributions to and memberships in charitable organizations
2. Organizations of the utility industry
3. Technical and professional organizations
4. Commercial and trade organizations
5. All other organizations and kinds of donations and contributions

List donations by type and group by the accounts charged. Report whole dollars only. Provide a total for each group of donations.

Description	Account Number	Total Amount	Amount Assigned to Oregon
1. Civic Contributions		$ 1,648,046	100%
2. Civic Memberships		33,314	100%
3. Corporate/Industrial Memberships		2,641,953	100%
4. Service Memberships		150	100%
(See attached for details)			
TOTAL		$ 4,323,463	

CIVIC CONTRIBUTIONS	ACCOUNT	AMOUNT
Air Show of the Cascades	426.1	$ 2,000
All Hands Raised	426.1	2,500
ALS Association of Oregon & SW Washington	426.1	4,450
American Heart Association, Inc	426.1	7,350
American Leadership Forum of Oregon	426.1	5,000
American Lung Association of Oregon	426.1	6,750
American Red Cross	426.1	25,000
American Red Cross - Willamette Chapter	426.1	9,500
Associated Oregon Industries	426.1	1,000
Basic Rights Oregon	426.1	7,500
Bicycle Transportation Alliance	426.1	1,500
Black United Fund of Oregon Inc.	426.1	1,500
Blue Ocean Events	426.1	10,000
Boardman Chamber of Commerce (sponsorship)	426.1	2,000
Boys and Girls Clubs of Portland Metropolitan Area	426.1	10,550
Boys and Girls Club of Salem	426.1	2,500
B.U.L.L. Session Charity Event	426.1	1,000
Business Education Compact	426.1	2,250
Business For Culture and the Arts (sponsorship)	426.1	5,000
Central Oregon Safety Health	426.1	1,000
Chehalem Valley Chamber of Commerce	426.1	2,000
Citizens Utility Board of Oregon (sponsorship)	426.1	7,000
City Club of Portland	426.1	6,000
City of Estacada (sponsorship)	426.1	1,000
City of Hillsboro	426.1	1,500
Clackamas County Historical Society	426.1	2,500
Classroom Law Project	426.1	1,500
Community Action Organization - Washington County (sponsorship)	426.1	3,375
Community Energy Project, Inc	426.1	10,000
Creative Advocacy Network	426.1	2,500
Cultural Advocacy Coalition	426.1	2,000
Dayton Education Foundation	426.1	1,000

CIVIC CONTRIBUTIONS	ACCOUNT	AMOUNT
Doernbecher Children's Hospital	426.1	2,725
Dougy Center for Grieving Children	426.1	5,100
Edison Electric Institute Foundation	426.1	15,000
Elders in Action	426.1	5,000
Environmental Education Association of Oregon (sponsorship)	426.1	1,000
Estacada Community Center	426.1	1,000
Estacada Public Library Foundation	426.1	1,000
Estacada Together	426.1	1,000
Family Building Blocks	426.1	5,400
Focus the Nation	426.1	6,150
Friends of Fairview (sponsorship)	426.1	1,000
Gilbert House Children's Museum	426.1	5,000
Grantmakers of Oregon and Southwest Washington	426.1	3,500
Greater Portland	426.1	10,000
Gresham Chamber of Commerce	426.1	3,500
Grow Oregon	426.1	15,000
Hands on Greater Portland	426.1	2,500
Harding University	426.1	1,613
Harold Backen Golf Tournament	426.1	2,000
Hillsboro Chamber of Commerce	426.1	2,100
Hispanic Metropolitan Chamber of Commerce	426.1	3,350
Human Solutions Inc.	426.1	1,500
Innovation Partnership	426.1	1,000
Japan America Society of Oregon	426.1	1,600
Jefferson County Livestock Association	426.1	1,000
Jefferson County Youth Organization	426.1	1,000
Junior Achievement	426.1	4,200
Juvenile Diabetes Research Foundation	426.1	3,900
Keizer Chamber of Commerce	426.1	2,000
Klickitat County Fair	426.1	1,000
Lady Minto Hospital on Salt Springs Island	426.1	1,000
League of Oregon Cities	426.1	1,500

CIVIC CONTRIBUTIONS	ACCOUNT	AMOUNT
Liberty House (sponsorship)	426.1	1,500
Marion County	426.1	1,500
Marylhurst University	426.1	1,500
Middlesex School	426.1	2,000
Mid Valley Mentors	426.1	2,500
Morrow County Livestock & Growers Assoc	426.1	3,000
Mt Hood Community College Foundation	426.1	2,500
Native Fish Society	426.1	3,500
Nonprofit Association of Oregon	426.1	1,000
North Clackamas County Chamber of Commerce	426.1	1,000
North Morrow Community Foundation	426.1	2,000
Northwest Environmental Business Council	426.1	3,250
Oklahoma Christian University	426.1	1,000
Oktoberfest, Inc.	426.1	2,000
OMSI	426.1	5,000
Oregon BEST	426.1	1,000
Oregon Burn Center at Legacy Emanuel Hospital	426.1	6,625
Oregon Business Association	426.1	2,500
Oregon Business Council	426.1	12,000
Oregon Children's Foundation	426.1	5,000
Oregon City Chamber of Commerce	426.1	1,200
Oregon Cultural Trust	426.1	2,500
Oregon Energy Services, Inc.	426.1	67,000
Oregon Food Bank, Inc.	426.1	7,050
Oregon Garden Foundation	426.1	1,000
Oregon Historical Society	426.1	80,700
Oregon Humane Society	426.1	1,175
Oregon Mentors	426.1	1,000
Oregon Restaurant and Lodging Association	426.1	1,250
Oregon State University Foundation	426.1	18,192
Oregon Tradeswomen, Inc.	426.1	7,800
Oregon Wildlife Heritage Foundation	426.1	1,000

CIVIC CONTRIBUTIONS	ACCOUNT	AMOUNT
Oregon Zoo Foundation	426.1	30,500
Pacific Northwest Economic Region	426.1	10,000
Pacific Northwest Lineman Rodeo Association	426.1	15,000
Peregrine Sports, LLC	426.1	265,225
PGE Employee Giving Campaign (various agencies)	426.1	518,734
Port of Morrow (sponsorship)	426.1	3,899
Portland Business Alliance	426.1	7,300
Portland Business Journal	426.1	17,500
Portland Rose Festival Association	426.1	78,000
Portland State University Foundation	426.1	7,500
Portland Streetcar, Inc.	426.1	10,000
Providence Medical Foundation	426.1	2,475
Providence Newberg Health Foundation	426.1	1,650
Redbridge, Inc. (sponsorship)	426.1	1,000
Renewable Northwest Project (sponsorship)	426.1	10,000
Salem Area Chamber of Commerce	426.1	12,350
Salem Hospital Foundation	426.1	1,500
Salvation Army	426.1	1,000
Sandy Area Chamber of Commerce	426.1	1,500
Schoolhouse Supplies	426.1	2,500
Snow-Cap Communities Charities	426.1	4,000
SOLV	426.1	20,800
Special Olympics Oregon, Inc.	426.1	1,900
Stand for Children Leadership Center (sponsorship)	426.1	1,000
Strategic Economic Development Corporation	426.1	1,770
Sustainable Northwest	426.1	1,000
The Children's Learning Center	426.1	1,000
The Family Young Men's Christian Association	426.1	1,000
The Museum at Warm Springs	426.1	6,000
The Piece (sponsorship)	426.1	3,000
Tualatin Chamber of Commerce	426.1	3,000
United Way of Mid-Willamette Valley	426.1	5,000

CIVIC CONTRIBUTIONS	ACCOUNT	AMOUNT
Urban League of Portland	426.1	22,500
Vision 2020 Drexel University College of Medicine (sponsorship)	426.1	2,000
Volunteers of America	426.1	2,500
West Linn Centennial (sponsorship)	426.1	2,500
Westside Economic Alliance (sponsorship)	426.1	1,500
Willamette Falls Heritage Area Coalition (sponsorship)	426.1	2,500
Willamette Heritage Center	426.1	2,000
Wilsonville Chamber of Commerce	426.1	2,500
World Arts Foundation, Inc.	426.1	1,000
YWCA OF Greater Portland	426.1	5,000
ITEMS UNDER $1,000		45,338
TOTAL 2013 CIVIC CONTRIBUTIONS		$ 1,648,046

CIVIC MEMBERSHIPS	ACCOUNT	AMOUNT
Gresham Chamber of Commerce	426.5	$ 5,000
Hispanic Metropolitan Chamber of Commerce	426.5	$ 1,800
Japan America Society of Oregon	426.5	$ 1,250
Oregon Sports Authority	426.5	$ 5,000
Portland-Sapporo Sister City Association	426.5	$ 1,000
Wilsonville Chamber of Commerce	426.5	$ 1,100
ITEMS UNDER $1,000	426.5	$ 13,164
TOTAL 2013 CIVIC MEMBERSHIPS		**$ 33,314**

CORP / INDUSTRIAL MEMBERSHIPS	ACCOUNT		AMOUNT
American Wind Energy Association	930.2	$	20,000
Associated Oregon Industries	426.5	$	28,660
Association of Corporate Contributions Professionals	426.5	$	6,000
Audubon Society of Portland	426.5	$	2,500
Avian Power Line Interaction Committee	930.2	$	5,000
Black & Veatch Corporation	930.2	$	11,500
Business Education Compact	426.5	$	3,500
CEAT International Inc. (CEATI)	930.2	$	25,305
CIS Security Benchmarks	930.2	$	9,000
Citizens Crime Commission	426.5	$	5,000
Clackamas County Business Alliance	426.5	$	1,000
Classroom Law Project - Madison Circle	426.5	$	2,000
Columbia Corridor Association	426.5	$	2,500
Columbia County Economic Team	426.5	$	2,500
Columbia-Willamette Clean Cities Coalition, Inc.	426.5	$	1,000
Common Ground Alliance	930.2	$	2,000
Corporate Executive Board	426.5	$	38,500
Curtiss-Wright Flow Control Co. - Scientech (RAPID)	930.2	$	21,400
Curtiss-Wright Flow Control Co. - Scientech (FOMIS)	506	$	19,200
Drive Oregon	426.5	$	2,000
East Metro Economic Alliance	426.5	$	1,650
Edison Electric Institute	930.2	$	439,756
Electric Power Research Institute, Inc	930.2	$	8,721
Grantmakers of Oregon and SW Washington	426.5	$	2,438
Greater Portland Inc	426.5	$	25,000
HOLTEC International (User's Group)	230	$	17,000
Human Resources Policy Association	921	$	8,500
International Institute of Business Analysis	930.2	$	3,753
International Swaps and Derivatives Association, Inc.	930.2	$	9,500
Manufacturing 21 Coalition	426.5	$	5,000
Metro Multifamily Housing Association	426.5	$	1,050
Montana Tax Foundation, Inc.	930.2	$	1,750
Multiple Engineering Co-op Program	930.2	$	2,800
National Coal Transportation Association	930.2	$	1,500
National Hydropower Association	930.2	$	34,536
National Safety Council	426.5	$	1,170

CORP / INDUSTRIAL MEMBERSHIPS	ACCOUNT		AMOUNT
Network of Employees for Traffic Safety	930.2	$	1,290
North American Energy Standards Board (NAESB)	930.2	$	7,000
Northern Tier Transmission Group	930.2	$	295,588
Northwest Business for Culture and the Arts (NWBCA)	426.5	$	5,000
Northwest Energy Coalition	930.2	$	29,400
Northwest Environmental Business Council (NEBC)	426.5	$	1,350
Northwest Public Power Association	930.2	$	1,560
Nuclear Procurement Issues Committee (NUPIC)	230	$	7,000
Oregon Business Association	426.5	$	13,250
Oregon Business Council	426.5	$	30,407
Oregon Coalition of Healthcare Purchasers	426.5	$	2,975
Oregon Economic Development	426.5	$	5,000
Oregon Joint Use Association	930.2	$	2,875
Oregon Solar Energy Industries	930.2	$	4,000
Oregon State University - Cascadia Lifelines Program	930.2	$	50,000
Oregonians for Food and Shelter	908	$	3,000
Pacific NW Utilities Conference Committee (PNUCC)	930.2	$	74,711
Partners for a Sustainable Washington County Community	426.5	$	2,500
Portland Business Alliance	426.5	$	29,000
Portland Metropolitan Building Owners & Managers Assoc	426.5	$	12,600
Portland Oregon Visitors Association	426.5	$	1,000
Public Affairs Council	426.5	$	2,600
Smart Grid Consumer Collaborative	930.2	$	5,000
Smart Grid Interoperability Panel	930.2	$	22,500
Smart Grid Oregon	930.2	$	5,000
Strategic Economic Development Corp. (SEDCOR)	426.5	$	2,500
The Freshwater Trust	426.5	$	2,500
Urban Greenspaces Institute	426.5	$	2,500
USNAP Alliance	426.5	$	5,000
Utility Pension Fund Study Group	930.2	$	3,300
Utility Variable Generation Integration Group	930.2	$	5,000
West Associates	930.2	$	28,756
Western Electricity Coordinating Council	930.2	$	1,137,174
Western Energy Institute	930.2	$	33,180
Western Governor's Association	930.2	$	10,000
Western LAMPAC	426.5	$	2,000

CORP / INDUSTRIAL MEMBERSHIPS	ACCOUNT	AMOUNT
Westside Economic Alliance	426.5	$ 10,000
Westside Transportation Alliance Inc.	426.5	$ 5,000
Wetlands Conservancy	426.5	$ 2,000
ITEMS UNDER $1,000	various	$ 5,748
TOTAL 2013 CORP INDUSTRIAL MEMBERSHIPS		$ 2,641,953

SERVICE MEMBERSHIPS	ACCOUNT	AMOUNT
ITEMS UNDER $1,000	426.5	$ 150
TOTAL 2013 SERVICE MEMBERSHIPS		**$ 150**

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STATE OF OREGON

DONATIONS OR PAYMENTS FOR SERVICES RENDERED BY PERSONS OTHER THAN EMPLOYEES AND CHARGED TO OREGON OPERATING ACCOUNTS

1. Report for each service rendered (including materials furnished incidental to the service which are impracticable of separation) by recipient and in total the aggregate of all payments made during the year where the aggregate of all such payments to a recipient was $25,000 or more including fees, retainers, commissions, gifts, contributions, assessments, bonuses, subscriptions, allowances for expenses or any other form of payments for services or as donations (except rents for property, taxes, utility services, traffic settlements, amounts paid for general services and licenses, accruals paid to trustees of pension and other employee benefit funds, and amounts paid for construction or maintenance of plant to persons other than affiliates) to any one corporation, institution, association, firm, partnership, committee, or person (not an employee of the respondent). Indicate by an asterisk in column (c) each item that includes payments for materials furnished incidental to the service performed. Payments to a recipient by two or more companies within a single system under a cost sharing or other joint arrangement shall be considered a single item for reporting in this schedule and shall be shown in the report of the principal company in the joint arrangement (as measured by gross operating revenues) with references thereto in the reports of the other system companies in the joint arrangement.

2. If more convenient, this schedule may be filled out for a group of companies considered as one system and shown only in the report of the principal company in the system, with references thereto in the reports of the other companies.

Line No.	Name of Recipient (a)	Nature of Service (b)	Amount of Payment (c)
	See attached		$ 19,315,556

Name	Service Description	Amount
A WORKSAFE SERVICE INC	Professional Services	45,184
A3O STUDIOS INC	Professional Services	61,140
ACCION GROUP INC	Professional Services	324,645
ACXIOM CORPORATION	Professional Services	40,000
AKIN GUMP STRAUSS HAUER & FELD LLP	Professional Services	467,093
ANDREA HAND MARKETING SVCS INC	Professional Services	89,060
ASSET CONTROL INC	Professional Services	71,845
ASW ENGINEERING	Professional Services	27,663
BAKER BOTTS LLP	Professional Services	37,852
BENEFITHELP SOLUTIONS INC	Professional Services	66,547
BLACK & VEATCH CORPORATION	Professional Services	128,014
BLUE LEAF ENVIRONMENTAL INC	Professional Services	127,948
BOARDMAN TREE FARM LLC	Professional Services	47,220
BRIDGEWATER GROUP INC	Professional Services	88,387
BROADRIDGE INVESTOR	Professional Services	81,719
BUCHANAN ANGELI	Professional Services	46,475
BURNS & MCDONNELL	Professional Services	184,908
BUSINESS WIRE INC	Professional Services	48,791
CASCADE ENGINEERING SERVICES INC	Professional Services	50,387
CATHERINE I MILLER	Professional Services	37,150
CELILO GROUP MEDIA INC	Professional Services	76,650
CHAPMAN & CUTLER LLP	Professional Services	34,273
CHRISTOPHER COLLINS	Professional Services	73,400
COMPUTERSHARE INC	Professional Services	26,698
CRA INTERNATIONAL INC	Professional Services	48,126
CULTURE CHANGE CONSULTANTS INC	Professional Services	41,850
CULVER COMPANY LLC	Professional Services	70,000
CUSTOMER RELATIONSHIP METRICS	Professional Services	67,395
CYNTHIA A CLASSEN	Professional Services	81,152
DAVID C BAMFORD	Professional Services	29,935
DAVID L BOURKE	Professional Services	35,399
DELOITTE & TOUCHE LLP	Professional Services	1,622,324
DIGITAL EVOLUTION GROUP LLC	Professional Services	70,985
DISTINCTION COMMUNICATION INC	Professional Services	38,750
DONNELLEY RECEIVABLES INC	Professional Services	56,173
DUNN CARNEY ALLEN HIGGINS AND TONGUE LLP	Professional Services	67,910
ECOLOGY AND ENVIRONMENT INC	Professional Services	51,306
ELECTRIC POWER RESEARCH INSTITUTE INC	Professional Services	105,115
EMERGE INTERACTIVE INC	Professional Services	42,863
ENGINEERING REMEDIATION RESOURCES GROUP	Professional Services	122,664
ENTRIX INC	Professional Services	79,180
EPIQ CLASS ACTION & CLAIM SOLUTIONS INC	Professional Services	31,102
ERM INFORMATION SOLUTIONS INC	Professional Services	70,235
ERM-WEST INC	Professional Services	227,180

Name	Service Description	Amount
FARRELL STRATEGIES INC	Professional Services	80,325
FFA ARCHITECTURE AND INTERIORS INC	Professional Services	150,630
FIGHT LLC	Professional Services	210,907
FORENSIC ANALYTICAL CONSULTING SERVICES	Professional Services	26,036
FORESEE RESULTS INC	Professional Services	80,000
FREDERIC W COOK & CO INC	Professional Services	160,508
FREDERICKSON FARMING LLC	Professional Services	30,681
FUCILE & REISING LLP	Professional Services	40,806
GANNETT FLEMMING INC	Professional Services	67,804
GARD COMMUNICATIONS INC	Professional Services	30,632
GARDA CL NORTHWEST INC	Professional Services	31,072
GARRAD HASSAN AMERICA INC	Professional Services	121,041
GOLIVE CONSULTING INC	Professional Services	67,935
GP STRATEGIES CORPORATION	Professional Services	83,450
GRANT THORNTON LLP	Professional Services	64,350
GROOM LAW GROUP CHARTERED	Professional Services	113,777
HAHN AND ASSOCIATES INC	Professional Services	29,705
HANSA GCR LLC	Professional Services	25,000
HARRANG LONG GARY RUDNICK PC	Professional Services	35,952
HDR ENGINEERING INC	Professional Services	25,442
HEWITT ASSOCIATES LLC	Professional Services	240,091
HITACHI CONSULTING CORPORATION	Professional Services	224,038
HODGKINSON STREET LLC	Professional Services	80,468
HOPE PATRICE LAMBERT	Professional Services	77,930
HSBC BANK USA NA CORP TRUST	Professional Services	41,897
IHS GLOBAL INC	Professional Services	55,357
INTERTEK USA INC	Professional Services	352,500
IRON MOUNTAIN INFO MGMT INC	Professional Services	33,518
JAMES H JOERGER ED D	Professional Services	91,313
JD POWER AND ASSOCIATES	Professional Services	87,000
JIMMY WAYNE BREWER	Professional Services	75,351
KARI L HASTINGS	Professional Services	50,675
KEITH R ROSS	Professional Services	30,064
KEMA INC	Professional Services	135,254
KLEINSCHMIDT ASSOCIATES	Professional Services	44,169
LAURITS R CHRISTENSEN ASSOCIATES INC	Professional Services	118,080
LEE DAVID LITCHY	Professional Services	356,308
MANAGEMENT COMPENSATION GROUP NW	Professional Services	110,000
MARIA VICTORIA LARA	Professional Services	80,378
MARK R LINDLEY	Professional Services	131,376
MARKET STRATEGIES	Professional Services	342,200
MARKOWITZ HERBOLD GLADE & MEHLHAF PC	Professional Services	180,912
MARTEN LAW SEATTLE PLLC	Professional Services	44,633
MERCER HEALTH & BENEFITS LLC	Professional Services	53,331

Name	Service Description	Amount
MERCER INVESTMENT CONSULTING	Professional Services	164,805
MERCER THOMPSON LLC	Professional Services	158,177
MERRILL LYNCH RETIREMENT AND BENEFIT SERVI(	Professional Services	41,100
MIKON CORPORATION	Professional Services	51,310
MORGAN LEWIS & BOCKIUS LLP	Professional Services	203,339
NORMANDEAU ASSOCIATES INC	Professional Services	87,256
NORTH INC	Professional Services	870,315
NYSE MARKET INC	Professional Services	78,492
OREGON CHILDREN'S THEATRE	Professional Services	31,136
OREGON STATE UNIVERSITY FOUNDATION	Professional Services	55,000
PERKINS COIE LLP	Professional Services	51,988
PHENOMENA INC	Professional Services	66,534
PORT OF MORROW	Professional Services	36,750
PORTLAND STATE UNIV FOUNDATION	Professional Services	70,000
POWERPLAN INC	Professional Services	116,018
R2 RESOURCE CONSULTANTS INC	Professional Services	33,187
RESEARCH INTO ACTION INC	Professional Services	53,583
REVENEW INTERNATIONAL LLC	Professional Services	67,656
RIDDELL WILLIAMS PS	Professional Services	605,507
RIVER ROCK INTERNATIONAL LLC	Professional Services	37,538
ROTHFUSS ENGINEERING COMPANY	Professional Services	367,323
SATHER BYERLY & HOLLOWAY	Professional Services	98,026
SCI 32 INC	Professional Services	45,000
SENSUS USA INC	Professional Services	25,000
SKADDEN ARPS SLATE MEAGHER & FLOM LLP	Professional Services	640,380
SLALOM LLC	Professional Services	235,330
SLOVER & LOFTUS LLP	Professional Services	60,170
SLR INTERNATIONAL CORP	Professional Services	136,208
SMITH CREATIVE GROUP	Professional Services	79,096
SOCIOTECHNICAL ADVISORS INC	Professional Services	67,043
SOLAR ELECTRIC POWER ASSOC	Professional Services	32,477
STANDARD & POOR'S FIN SRVC LLC	Professional Services	191,070
STANDING STONE CORPORATION	Professional Services	27,935
STOEL RIVES LLP	Professional Services	414,807
SUNGARD AVAILABILITY SRVCS LP	Professional Services	77,400
SUSAN BARD & MICHAEL OLSON INC	Professional Services	25,150
SUSAN VOGT	Professional Services	52,925
THE CORAGGIO GROUP INC	Professional Services	224,038
THE JK GROUP INC	Professional Services	37,792
THERESA HAGERTY	Professional Services	76,075
THOMAS E EBZERY PC	Professional Services	39,371
THOMAS J GALLAGHER	Professional Services	88,998
TONKON TORP LLP	Professional Services	331,453
TOWERS WATSON PA INC	Professional Services	206,714

Name	Service Description	Amount
TRC ENVIRONMENTAL CORPORATION	Professional Services	127,800
TRINITY CONSULTANTS INC	Professional Services	49,919
TWO BY FORE INC	Professional Services	38,710
URS CORPORATION	Professional Services	2,110,609
UTILITIES INTERNATIONAL INC	Professional Services	40,959
UTILITY RESOURCES INC	Professional Services	39,480
VAN HUEVELEN STRATEGIES	Professional Services	72,011
VAN NESS FELDMAN LLP	Professional Services	42,431
VAROLII CORPORATION	Professional Services	459,253
VOCUS INC	Professional Services	36,414
ZACHRY ENGINEERING CORPORATION	Professional Services	82,913
TOTAL 2013 DONATIONS AND PAYMENTS		19,315,556

Portland General Electric Company

2013 ANNUAL REPORT

Portland General Electric

To Our Shareholders | Portland General Electric continues to deliver value to our stakeholders through our mission of powering our customers' potential as the region's trusted energy partner.

2013 was a big year for PGE: We entered into agreements for three new long-term generation resources that will help us deliver a sustainable, affordable energy future; we worked with our regulators and stakeholders to establish new customer prices; and we maintained high customer satisfaction ratings in all classes, including top decile in overall system reliability with large customers, according to national research. These company achievements demonstrate our employees' commitment to our core business strategy and creation of value for all our stakeholders.

Operational Excellence

2013 was a strong year in overall operational performance. Our distribution system operated with high reliability, and despite outages at Boardman and Coyote Springs, generation availability at PGE-operated plants was on target. PGE continues to make improvements across the company to be more efficient and cost effective and improve our employees' safety through targeted programs.

For 2013, PGE delivered net income of $105 million, or $1.35 per diluted share, for a 5.9 percent return on equity. Our strong operational performance was impacted by the termination of the Cascade Crossing Transmission Project, a customer billing refund, and incremental replacement power costs due to plant outages in the second half of 2013.

We made the decision to discontinue our work on the Cascade Crossing Transmission Project when we determined that, as a result of a change in regional demand driven by limitations on renewable exports to California, the project was no longer the best alternative for our customers. We are confident this was the correct decision given current conditions.

Weather-adjusted energy deliveries in 2013 were comparable to the previous year. In 2014, we anticipate an overall increase of about 1 percent, attributed to industrial customers as demand from the high-tech sector is expected to increase.

In 2013, PGE filed a general rate case, our first since 2010. We received approval from the Oregon Public Utility Commission to increase base customer prices by approximately 4 percent beginning Jan. 1, 2014, with a revenue requirement based on a 9.75 percent allowed return on equity. With two of the three new generation projects expected to begin serving customers in the first half of 2015, PGE initiated a new general rate case in 2014 requesting the commission approve an overall price increase of 4.6 percent, effective early 2015.

We continue to invest in our business with capital expenditures of $656 million in 2013. These investments included expenditures related to the three new generation projects, a new emergency readiness center, and continued investments in our transmission and distribution system to build capacity, increase reliability and improve power quality for customers. PGE continues to maintain strong overall credit quality, which supports our ability to finance ongoing investments. At year-end, our equity-to-total capital ratio was 49 percent, and our investment-grade credit ratings for secured debt were A– and A1 by Standard & Poor's and Moody's, respectively, which keeps our financing costs low for customers.

Business Growth

Construction is underway on all three generation projects selected last year through the competitive bidding processes, and each of these projects continues to be on time and on budget. We are building Port Westward Unit 2, a 220 MW natural gas capacity plant next to our existing Port Westward plant in Clatskanie, Ore., and it is expected to come online in the first quarter of 2015. Tucannon River Wind Farm is expected to come fully online in the first half of 2015, with nameplate capacity of 267 MW. Carty Generating Station, a 440 MW natural gas-fired plant, is being constructed next to our existing Boardman plant and is expected to become operational in mid-2016. The three new plants will be owned and operated by PGE for a cumulative investment during four years of $1.25 billion.

Looking Forward

In 2014, we are focused on continually emphasizing operational excellence and the construction of three new generation resources on time and on budget.

Corporate Responsibility

We continue to work with businesses, community leaders and local governments to support the economic growth of our region — because the region's success is our success. I am especially proud of our employees' continued commitment to the communities in which we live and serve. For the sixth year in a row, PGE employees and retirees pledged more than $1 million for charitable causes, benefiting more than 950 nonprofits and schools. PGE employees also logged more than 35,000 hours of volunteer time in our communities in 2013.

I am proud of the hard work and achievements that took place in all corners of the company in 2013. Our employees' commitment and dedication to serving our customers is the key to our success. Together with my co-workers, we will continue our efforts in 2014 to provide safe, reliable, sustainable power for Oregon's energy future, which will deliver value to our customers, shareholders, and the communities we serve.

Sincerely,

Jim Piro

Jim Piro | President and Chief Executive Officer

Financial Highlights

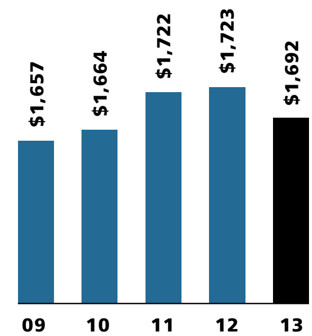
About Portland General Electric

Portland General Electric Company, headquartered in Portland, Ore., is a fully integrated electric utility serving approximately 836,000 residential, commercial and industrial customers in Oregon. PGE common stock is traded on the New York Stock Exchange under the ticker symbol POR.

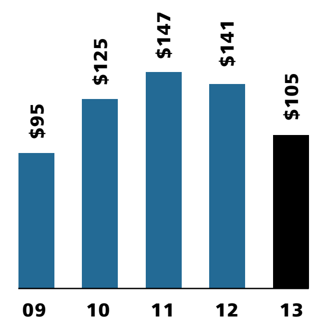
(Dollars in millions, except per share amounts)	2013	2012	2011
Operating revenues	$1,810	$1,805	$1,813
Net operating income	$206	$302	$309
Net income for common stock	$105	$141	$147
Return on average quarter-end equity	5.9%	8.2%	9.0%
Total assets	$6,101	$5,670	$5,733
Dividends declared per common share	$1.095	$1.075	$1.055
Weighted-average shares outstanding (in thousands), diluted	77,388	75,647	75,350
Customers	836,070	828,354	822,466
Long-term debt, including current portion	$1,916	$1,636	$1,735
Long-term debt/capitalization	51.3%	48.4%	50.6%
Senior secured debt ratings (S&P/Moody's)	A-/A1	A-/A3	A-/A3
Commercial paper ratings (S&P/Moody's)	A-2/P-2	A-2/P-2	A-2/P-2
Employees	2,596	2,603	2,634

Stock Performance Graph

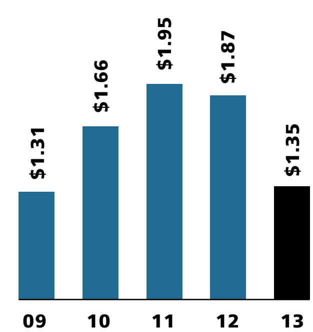
1. Assumes a $100 investment in Portland General Electric's common stock and each index on December 31, 2008, and that all dividends were reinvested.



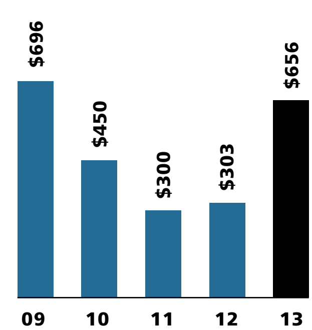
TOTAL RETAIL REVENUE



NET INCOME



EARNINGS PER SHARE (DILUTED)



CAPITAL EXPENDITURES

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

[x] **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2013

OR

[ ] **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Transition period from ______ to ______

Commission File Number 001-05532-99

PORTLAND GENERAL ELECTRIC COMPANY

(Exact name of registrant as specified in its charter)

Oregon	**93-0256820**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

121 S.W. Salmon Street
Portland, Oregon 97204
(503) 464-8000
(Address of principal executive offices, including zip code,
and Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Common Stock, no par value	**New York Stock Exchange**
(Title of class)	(Name of exchange on which registered)

Securities registered pursuant to Section 12(g) of the Act: None.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes [x] No [ ]

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes [ ] No [x]

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes [x] No [ ]

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Date File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes [x] No [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [x]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definition of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	[x]	Accelerated filer	[ ]
Non-accelerated filer	[ ]	Smaller reporting company	[ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes [ ] No [x]

As of June 28, 2013, the aggregate market value of voting common stock held by non-affiliates of the Registrant was $2,358,020,964. For purposes of this calculation, executive officers and directors are considered affiliates.

As of February 10, 2014, there were 78,086,174 shares of common stock outstanding.

Documents Incorporated by Reference

Part III, Items 10 - 14	Portions of Portland General Electric Company's definitive proxy statement to be filed pursuant to Regulation 14A for the Annual Meeting of Shareholders to be held on May 7, 2014.

PORTLAND GENERAL ELECTRIC COMPANY
FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2013

TABLE OF CONTENTS

DEFINITIONS

The abbreviations or acronyms defined below are used throughout this Form 10-K:

Abbreviation or Acronym	Definition
AFDC	Allowance for funds used during construction
ARO	Asset retirement obligation
AUT	Annual Power Cost Update Tariff
Beaver	Beaver natural gas-fired generating plant
Biglow Canyon	Biglow Canyon Wind Farm
Boardman	Boardman coal-fired generating plant
BPA	Bonneville Power Administration
CAA	Clean Air Act
Carty	Carty Generating Station natural gas-fired generating plant
Colstrip	Colstrip Units 3 and 4 coal-fired generating plant
Coyote Springs	Coyote Springs Unit 1 natural gas-fired generating plant
CWIP	Construction work-in-progress
Dth	Decatherm = 10 therms = 1,000 cubic feet of natural gas
DEQ	Oregon Department of Environmental Quality
EFSA	Equity forward sale agreement
EPA	United States Environmental Protection Agency
ESS	Electricity Service Supplier
FERC	Federal Energy Regulatory Commission
FMB	First Mortgage Bond
IRP	Integrated Resource Plan
ISFSI	Independent Spent Fuel Storage Installation
kV	Kilovolt = one thousand volts of electricity
Moody's	Moody's Investors Service
MW	Megawatts
MWa	Average megawatts
MWh	Megawatt hours
NRC	Nuclear Regulatory Commission
NVPC	Net Variable Power Costs
OATT	Open Access Transmission Tariff
OPUC	Public Utility Commission of Oregon
PCAM	Power Cost Adjustment Mechanism
Port Westward	Port Westward natural gas-fired generating plant
PW2	Port Westward Unit 2 natural gas-fired generating plant
RPS	Renewable Portfolio Standard
S&P	Standard & Poor's Ratings Services
SEC	United States Securities and Exchange Commission
Trojan	Trojan nuclear power plant
Tucannon River	Tucannon River Wind Farm
USDOE	United States Department of Energy
VIE	Variable interest entity

PART I

ITEM 1. BUSINESS.

General

Portland General Electric Company (PGE or the Company) is a vertically integrated electric utility engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the state of Oregon. The Company operates as a cost-based, regulated electric utility, with revenue requirements and customer prices determined based on the forecasted cost to serve retail customers, and a reasonable rate of return as determined by the Public Utility Commission of Oregon (OPUC). PGE's retail load requirement is met with both Company-owned generation and power purchased in the wholesale market. The Company also participates in the wholesale market by purchasing and selling electricity and natural gas in an effort to obtain reasonably-priced power for its retail customers. PGE was incorporated in 1930, is publicly-owned, with its common stock listed on the New York Stock Exchange, and 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 state-approved service area allocation of approximately 4,000 square miles is located entirely within Oregon and includes 52 incorporated cities, of which Portland and Salem are the largest. The Company estimates that at the end of 2013 its service area population was 1.7 million, comprising approximately 44% of the state's population. During 2013, the Company added 7,716 customers and as of December 31, 2013, served a total of 836,070 retail customers.

PGE had 2,596 employees as of December 31, 2013, with 795 employees covered under one of 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.

Available Information

PGE's Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available and may be accessed free of charge through the Investors section of the Company's Internet website at PortlandGeneral.com as soon as reasonably practicable after the reports are electronically filed with, or furnished to, the United States Securities and Exchange Commission (SEC). It is not intended that PGE's website and the information contained therein or connected thereto be incorporated into this Annual Report on Form 10-K. Information may also be obtained via the SEC Internet website at sec.gov.

Regulation

PGE is subject to both federal and state regulation, which can have a significant impact on the operations of the Company. In addition to those agencies and activities discussed below, the Company is subject to regulation by certain environmental agencies, as described in the Environmental Matters section in this Item 1.

Federal Regulation

PGE is subject to regulation by several federal agencies, including the Federal Energy Regulatory Commission (FERC), the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA), and the Nuclear Regulatory Commission (NRC).

FERC Regulation

The Company is a "licensee," a "public utility," and a "user, owner and operator of the bulk power system," as defined in the Federal Power Act, and is subject to regulation by the FERC in matters related to wholesale energy activities, transmission services, reliability and cyber security standards, natural gas pipelines, hydroelectric projects, accounting policies and practices, short-term debt issuances, and certain other matters.

Wholesale Energy—PGE has authority under its FERC Market-Based Rates tariff to charge market-based rates for wholesale energy sales. Re-authorization for continued use of such rates requires the filing of triennial market power studies with the FERC. The Company filed an updated triennial market power study in June 2013 and is awaiting an Order from the FERC.

Transmission—PGE offers transmission service pursuant to its Open Access Transmission Tariff (OATT), which is filed with the FERC. As required by the OATT, PGE provides information regarding its transmission business on its Open Access Same-time Information System, also known as OASIS. As of December 31, 2013, PGE owned 1,141 circuit miles of transmission lines. For additional information, see the Transmission and Distribution section in this Item 1. and in Item 2.—"Properties."

Reliability and Cyber Security Standards—Pursuant to the Energy Policy Act of 2005, the FERC has adopted mandatory reliability standards for owners, users and operators of the bulk power system. Such standards, which are applicable to PGE, were developed by the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC), which have responsibility for compliance and enforcement of these standards. These standards include Critical Infrastructure Protection (CIP) standards, a set of cyber security standards that provide a framework to identify and protect critical cyber assets used to support reliable operation of the bulk power system.

Pipeline—The Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978 provide the FERC authority in matters related to the extension, enlargement, safety, and abandonment of jurisdictional pipeline facilities, as well as transportation rates and accounting for interstate natural gas commerce. PGE is subject to such authority as the Company has a 79.5% ownership interest in and is the operator of record of the Kelso-Beaver Pipeline, a 17-mile interstate pipeline that provides natural gas to the Company's Port Westward natural gas-fired generating plant (Port Westward) and Beaver natural gas-fired generating plant (Beaver). As the operator of record, PGE is subject to the requirements and regulations enacted under the Pipeline Safety Laws administered by the PHMSA, which include safety standards, operator qualification standards and public awareness requirements.

Hydroelectric Licensing—Under the Federal Power Act, PGE's hydroelectric generating plants are subject to FERC licensing requirements. These include an extensive public review process that involves the consideration of numerous natural resource issues and environmental conditions. PGE holds FERC licenses for the Company's projects on the Deschutes, Clackamas, and Willamette Rivers. For additional information, see the Environmental Matters section in this Item 1. and Generating Facilities section in Item 2.—"Properties."

Accounting Policies and Practices—Pursuant to applicable provisions of the Federal Power Act, PGE prepares financial statements in accordance with the accounting requirements of the FERC, as set forth in its applicable Uniform System of Accounts and published accounting releases. Such financial statements are included in annual and quarterly reports filed with the FERC.

Short-term Debt—Pursuant to applicable provisions of the Federal Power Act and FERC regulations, regulated public utilities are required to obtain FERC approval to issue certain securities. The Company, pursuant to an order issued by the FERC on February 3, 2014, is authorized to issue up to $900 million of short-term debt through February 6, 2016.

NRC Regulation

The NRC regulates the licensing and decommissioning of nuclear power plants, including PGE's Trojan nuclear power plant (Trojan), which was closed in 1993. The NRC approved the 2003 transfer of spent nuclear fuel from a spent fuel pool to a separately licensed dry cask storage facility that will house the fuel on the plant site until a United States Department of Energy (USDOE) facility is available. Radiological decommissioning of the plant site was completed in 2004 under an NRC-approved plan, with the plant's operating license terminated in 2005. Spent fuel storage activities will continue to be subject to NRC regulation until all nuclear fuel is removed from the site and radiological decommissioning of the storage facility is completed. For additional information on spent nuclear fuel storage activities, see Note 7, Asset Retirement Obligations in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

State of Oregon Regulation

PGE is subject to the jurisdiction of the OPUC, which is comprised of three members appointed by Oregon's governor to serve non-concurrent four-year terms.

The OPUC reviews and approves the Company's retail prices (see "*Ratemaking*" below) and establishes conditions of utility service. In addition, the OPUC reviews the Company's generation and transmission resource acquisition plans, pursuant to an integrated resource planning process. The OPUC also regulates the issuance of securities, prescribes accounting policies and practices, and reviews both applications to sell utility assets and engage in transactions with affiliated companies and applications to acquire substantial influence over a public utility.

Oregon's Energy Facility Siting Council (EFSC) has regulatory and siting responsibility for large electric generating facilities, high voltage transmission lines, intrastate gas pipelines, and radioactive waste disposal sites. The EFSC also has responsibility for overseeing the decommissioning of Trojan. The seven volunteer members of the EFSC are appointed to four-year terms by Oregon's governor, with staff support provided by the Oregon Department of Energy.

Integrated Resource Plan—Unless the OPUC directs otherwise, PGE is required to file with the OPUC an Integrated Resource Plan (IRP) within two years of its previous IRP acknowledgment order. Based on direction from the OPUC, PGE is required to file its next IRP by the end of March 2014. The IRP guides the utility on how it will meet future customer demand and describes the Company's future energy supply strategy, reflecting new technologies, market conditions, and regulatory requirements. The primary goal of the IRP is to identify an acquisition plan for generation, transmission, demand-side and energy efficiency resources that, along with the Company's existing portfolio, provides the best combination of expected cost and associated risks and uncertainties for PGE and its customers. For additional information on PGE's most recent IRP, see "*Future Energy Resource Strategy*" in the Power Supply section in this Item 1.

Economic Regulation—Under Oregon law, the OPUC is required to ensure that prices and terms of service are fair, non-discriminatory, and provide regulated companies an opportunity to earn a reasonable return on their investments. Customer prices are determined through formal proceedings that generally include testimony by participating parties, discovery, public hearings, and the issuance of a final order. Participants in such proceedings, which are conducted under established procedural schedules, include PGE, OPUC staff, and intervenors representing PGE customer groups. The following are the more significant regulatory mechanisms and proceedings under which customer prices are determined:

- *General Rate Cases*. PGE periodically evaluates the need to change its retail electric price structure to sufficiently cover its operating costs and provide a reasonable rate of return. Such changes are requested pursuant to a comprehensive general rate case process that includes revenue requirements based on a forecasted test year, debt-to-equity capital structure, return on equity, and overall rate of return. PGE's most recent general rate case was the 2014 General Rate Case, which became effective on January 1, 2014. On February 13, 2014, PGE filed a general rate case with a 2015 test year (2015 General Rate Case), for which a final order is expected to be received in December 2014. New prices are expected to be effective in 2015, with the first price increase effective January 1 and two additional price increases effective as two new generating plants become operational, which is expected in the first half of 2015. For additional information, see the Overview section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

- *Power Costs*. In addition to price changes resulting from the general rate case process, the OPUC has approved the following mechanisms by which PGE can adjust retail customer prices to cover the Company's Net Variable Power Costs (NVPC), which consist of the cost of purchased power and fuel used in generation (including related transportation costs) less revenues from wholesale power and fuel sales:
  - Annual Power Cost Update Tariff (AUT). Under this tariff, customer prices are adjusted annually to reflect the latest forecast of NVPC. Such forecasts assume the following for the different types of PGE-owned generating resources;
    - Thermal—expected operating conditions;
    - Hydroelectric—Average regional hydro conditions (based on seventy years of stream flow data covering the period 1928 - 1998) and current hydro operating parameters; and
    - Wind—Average wind conditions based on a five-year historical rolling average of the wind farm. To the extent historical information is not available for a given year, the projections will be based on wind studies developed prior to the operation of the facility.

    An initial NVPC forecast, submitted to the OPUC by April 1st each year, is updated during such year and finalized in November of the same year. Based upon the final forecast, new prices, as approved by the OPUC, become effective at the beginning of the next calendar year; and
  - Power Cost Adjustment Mechanism (PCAM). Customer prices can also be adjusted to reflect a portion of the difference between each year's forecasted NVPC included in prices (baseline NVPC) and actual NVPC for the year. Under the PCAM, PGE is subject to a portion of the business risk or benefit associated with the difference between actual NVPC and baseline NVPC. The PCAM utilizes an asymmetrical deadband range within which PGE absorbs cost variances, with a 90/10 sharing of such variances between customers and the Company outside of the deadband. The deadband range is $15 million below, to $30 million above, baseline NVPC. Annual results of the PCAM are subject to application of a regulated earnings test, under which 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. 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. A final determination of any customer refund or collection is made by the OPUC through a public filing and review typically during the second half of the following year. For additional information, see the Results of Operations section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."
- *Renewable Energy.* The 2007 Oregon Renewable Energy Act (the Act) established a Renewable Portfolio Standard (RPS) which requires that PGE serve at least 5% of its retail load with renewable resources by 2011, 15% by 2015, 20% by 2020, and 25% by 2025. PGE met the 2011 requirement and expects to have sufficient resources to meet the 2015 requirements with the Tucannon River Wind Farm (Tucannon River), which is expected to become operational in the first half of 2015.

  The Act also allows Renewable Energy Credits, resulting from energy generated from qualified renewable resources placed in service after January 1, 1995 and certified low impact hydroelectric power resources, to be used to meet the Company's RPS compliance obligation.

  The Act also provides for the recovery in customer prices of all prudently incurred costs required to comply with the RPS. Under a renewable adjustment clause (RAC) mechanism, PGE can recover the revenue requirement of new renewable resources and associated transmission that are not yet included in prices. Under the RAC, PGE submits a filing by April 1st of each year for new renewable resources expected to be placed in service in the current year, with prices to become effective January 1st of the following year. In addition, the RAC provides for the deferral and subsequent recovery of eligible costs incurred prior to January 1st of the following year.

For additional information, see the "Legal, Regulatory and Environmental Matters" discussion in the Overview section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

As needed, other ratemaking proceedings occur and can involve charges or credits related to specific costs, programs, or activities, as well as the recovery or refund of deferred amounts recorded pursuant to specific OPUC authorization. Such amounts are generally collected from, or refunded to, retail customers through the use of supplemental tariffs.

Retail Customer Choice Program—PGE's commercial and industrial customers have access to pricing options other than cost-of-service, including direct access and daily market index-based pricing. All commercial and industrial customers are eligible for direct access, whereby customers purchase their electricity from an Electricity Service Supplier (ESS), and the Company continues to deliver the energy to the customers. Large commercial and industrial customers may elect to be served by PGE on a daily market index-based price. Certain large commercial and industrial customers may elect to be removed from cost-of-service pricing for a fixed three-year or a minimum five-year term, to be served either by an ESS or the Company under a daily market index-based price. Participation in the fixed three-year and minimum five-year opt-out programs is capped at, in aggregate, 300 average megawatts (MWa).

The majority of the energy supplied under PGE's Retail Customer Choice program is provided to customers that have elected service from an ESS under the minimum five-year opt-out program. In 2013, ESSs supplied direct access customers with a total retail load representing 8% of the Company's total retail energy deliveries for the year, with 6% in 2012. The maximum retail load allowed to be supplied under the fixed three-year and minimum five-year opt-out programs would represent approximately 14% of the Company's total retail energy deliveries for 2013 and 2012.

The retail customer choice program has no material impact on the Company's financial condition or operating results. Revenue changes resulting from increases or decreases in electricity sales to direct access customers are substantially offset by changes in the Company's cost of purchased power and fuel. Further, the program provides for "transition adjustment" charges or credits to direct access and market based pricing customers that reflect the above- or below-market cost of energy resources owned or purchased by the Company. Such adjustments are designed to ensure that the costs or benefits of the program do not unfairly shift to those customers that continue to purchase their energy requirements from the Company.

In addition to cost-of-service pricing, residential and small commercial customers can select portfolio options from PGE that include time-of-use and renewable resource pricing.

Energy Efficiency Funding—Oregon law provides for a "public purpose charge" to fund cost-effective energy efficiency measures, new renewable energy resources, and weatherization measures for low-income housing. This charge, equal to 3% of retail revenues, is collected from customers and remitted to the Energy Trust of Oregon (ETO) and other agencies for administration of these programs. Approximately $48 million, $50 million and $51 million was collected from customers for this charge in 2013, 2012 and 2011, respectively.

In addition to the public purpose charge, PGE also remits to the ETO amounts collected under an Energy Efficiency Adjustment tariff to fund additional energy efficiency measures. This charge was approximately 3.5%, 2.7% and 1.8% of retail revenues for applicable customers in 2013, 2012 and 2011, respectively. Under the tariff, approximately $50 million, $41 million and $28 million was collected from eligible customers in 2013, 2012 and 2011, respectively.

Decoupling—The decoupling mechanism, authorized through 2016, is intended to provide for recovery of margin lost as a result of a reduction in electricity sales attributable to energy efficiency and conservation efforts by residential and certain commercial customers. The mechanism provides for collections from customers if weather adjusted use per customer is lower than levels included in the Company's most recent general rate case; it also provides for customer refunds if weather adjusted use per customer exceeds levels included in the most recent general rate case. The following is a summary of the impacts of the decoupling mechanism for the last three years:

- In 2013, PGE recorded an estimated collection of $5 million, of which $2 million related to an update for 2012. Pending review and approval by the OPUC, any resulting collection from customers would be expected over a one-year period beginning January 1, 2015.
- In 2012, the Company originally recorded an estimated refund of $1 million. After review in 2013, the OPUC ultimately approved a collection of $1 million, which is included in customer prices over a one-year period that began June 1, 2013.
- In 2011, PGE recorded an estimated refund of $2 million. The OPUC approved refunds to customers over a one-year period that began June 1, 2012.

Regulatory Accounting

PGE is subject to accounting principles generally accepted in the United States of America (GAAP), and as a regulated public utility, the effects of rate regulation are reflected in its financial statements. These principles provide for the deferral as regulatory assets of certain actual or estimated costs that would otherwise be charged to expense, based on expected recovery from customers in future prices. Likewise, certain actual or anticipated credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on expected future credits or refunds to customers. PGE records regulatory assets or liabilities if it is probable that they will be reflected in future prices, based on regulatory orders or other available evidence.

The Company periodically assesses the applicability of regulatory accounting to its business, considering both the current and anticipated future rate environment and related accounting guidance. For additional information, see "*Regulatory Assets and Liabilities*" in Note 2, Summary of Significant Accounting Policies, and Note 6, Regulatory Assets and Liabilities, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Customers and Revenues

PGE generates revenue through the sale and delivery of electricity to retail customers. The Company conducts retail electric operations exclusively in Oregon within a service area approved by the OPUC. Within its service territory, the Company competes with: i) the local natural gas distribution company for the energy needs of residential and commercial space heating, water heating, and appliances; and ii) fuel oil suppliers, primarily for residential customers' space heating needs. In addition, the Company distributes power to commercial and industrial customers that choose to purchase their energy supply from an ESS. The Company includes such "direct access" customers in its customer counts and energy delivered to such customers in its total retail energy deliveries, as reflected in the tables below. Retail revenues include only delivery charges and transition adjustments for these customers.

Retail Revenues

Retail customers are classified as residential, commercial, or industrial, with no single customer representing more than 4% of PGE's total retail revenues or 6% of total retail deliveries. While the 20 largest commercial and industrial customers constituted 12% of total retail revenues in 2013, they represented nine different groups including high technology, paper manufacturing, metal fabrication, health services, and governmental agencies.

PGE's Retail revenues (dollars in millions), retail energy deliveries (MWh in thousands), and average number of retail customers consist of the following for the years presented:

	Years Ended December 31,					
	2013		2012		2011	
Retail revenues[1] (dollars in millions):						
Residential	$ 861	51%	$ 860	50%	$ 877	51%
Commercial	619	36	633	37	635	37
Industrial	217	13	226	13	226	13
Subtotal	1,697	100	1,719	100	1,738	101
Other accrued (deferred) revenues, net	(5)	—	4	—	(16)	(1)
Total retail revenues	$ 1,692	100%	$ 1,723	100%	$ 1,722	100%
Retail energy deliveries[2] (MWh in thousands):						
Residential	7,702	40%	7,505	39%	7,733	40%
Commercial	7,441	38	7,402	39	7,419	38
Industrial	4,276	22	4,283	22	4,193	22
Total retail energy deliveries	19,419	100%	19,190	100%	19,345	100%
Average number of retail customers:						
Residential	728,481	87%	723,440	87%	719,977	87%
Commercial	104,385	13	103,766	13	102,940	13
Industrial	263	—	261	—	255	—
Total	833,129	100%	827,467	100%	823,172	100%

(1) Includes both revenues from customers who purchase their energy supplies from the Company and revenues from the delivery of energy to those commercial and industrial customers that purchase their energy from ESSs.

(2) Includes both energy sold to retail customers and energy deliveries to those commercial and industrial customers that purchase their energy from ESSs.

Additional averages for retail customers are as follows:

	Years Ended December 31,		
	2013	2012	2011
Usage per customer (in kilowatt hours):			
Residential	10,572	10,375	10,740
Commercial	71,284	71,343	72,075
Industrial	16,257,517	16,409,211	16,572,913
Revenue per customer (in dollars):			
Residential	$ 1,106	$ 1,113	$ 1,160
Commercial	5,840	6,041	6,194
Industrial	786,390	863,402	900,805
Revenue per kilowatt hour (in cents):			
Residential	10.46¢	10.72¢	10.80¢
Commercial	8.19	8.47	8.59
Industrial	4.84	5.26	5.44

For additional information, see the Results of Operations section in Item 7.—“Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

In accordance with state regulations, PGE’s retail customer prices are based on the Company’s cost of service and are determined through general rate case proceedings and various tariff filings with the OPUC. Additionally, the Company offers different pricing options including a daily market price option, various time-of-use options, and several renewable energy options, which are offered to residential and small commercial customers. For additional information on customer options, see “*Retail Customer Choice Program*” within the Regulation section of this Item 1. Additional information on the customer classes follows.

Residential customers include single family housing, multiple family housing (such as apartments, duplexes, and town homes), mobile homes, and small farms. Residential demand is sensitive to the effects of weather, with demand historically highest during the winter heating season; although, increased use of air conditioning in PGE’s service territory has caused the summer peaks to increase in recent years. Economic conditions can also affect residential demand, as historical data suggests that high unemployment rates contribute to a decrease in residential deliveries. Residential demand is also impacted by energy efficiency measures; however, the Company’s decoupling mechanism is intended to mitigate the financial effects of such measures.

During 2013, as a result of cooler weather during the 2013 heating season and an increase in the average number of customers, total residential deliveries increased 2.6% compared to 2012. While the number of residential customers increased during 2012, total residential deliveries decreased 2.9% compared to 2011 driven by warmer weather conditions during the 2012 heating season. On a weather adjusted basis, energy deliveries to residential customers increased by 1% in 2013 when compared to 2012.

Commercial customers consist of non-residential customers who accept energy deliveries at voltages equivalent to those delivered to residential customers. This customer class includes most businesses, small industrial companies, and public street and highway lighting accounts.

Demand from the Company’s commercial customers is somewhat less susceptible to weather conditions than the residential class, although weather does have an effect on commercial demand. Economic conditions and fluctuations in total employment in the region can also lead to corresponding changes in energy demand from commercial customers. Commercial demand is also impacted by energy efficiency measures, the financial effects of which are partially mitigated by the Company’s decoupling mechanism.

In 2013, the favorable weather effects and an increase in the average number of customers contributed to the 0.5% increase in commercial deliveries compared with 2012. In 2012, deliveries to commercial customers decreased

0.2% compared with 2011, which was primarily due to unfavorable weather effects relative to 2011, and largely offset by the addition of an average of over 800 new customers.

Industrial customers consist of non-residential customers who accept delivery at higher voltages than commercial customers, with pricing based on the amount of electricity delivered on the applicable tariff. Demand from industrial customers is primarily driven by economic conditions, with weather having little impact on this customer class.

A change in economic activity can lead to a change in energy demand from the Company's industrial customers. The Company's industrial energy deliveries decreased 0.2% in 2013 from 2012 and increased 2.1% in 2012 from 2011, driven primarily by changes in demand from certain paper production customers.

Other accrued (deferred) revenues, net includes items that are not currently in customer prices, but are expected to be in prices in a future period. Such amounts include deferrals recorded under the RAC, the PCAM, and the decoupling mechanism. For further information on these items, see "*State of Oregon Regulation*" in the Regulation section of this Item 1.

Wholesale Revenues

PGE participates in the wholesale electricity marketplace in order to balance its supply of power to meet the needs of its retail customers. Interconnected transmission systems in the western United States serve utilities with diverse load requirements and allow the Company to purchase and sell electricity within the region depending upon the relative price and availability of power, hydro conditions, and daily and seasonal retail demand. Wholesale revenues represented 4% of total revenues in 2013 and 3% in 2012 and 2011.

The majority of PGE's wholesale electricity sales are to utilities and power marketers and are predominantly short-term. The Company may net purchases and sales with the same counterparty rather than simultaneously receiving and delivering physical power; in such cases, only the net amount of those purchases or sales required to meet retail and wholesale obligations will be physically settled.

Other Operating Revenues

Other operating revenues consist primarily of gains and losses on the sale of excess natural gas, as well as revenues from transmission services, excess transmission capacity resales, excess fuel oil sales, pole contact rentals, and other electric services provided to customers. Other operating revenues represented 2% of total revenues in 2013, 2012, and 2011.

Seasonality

Demand for electricity by PGE's residential and, to a lesser extent, commercial customers, is affected by seasonal weather conditions. The Company uses heating and cooling degree-days to determine the effect of weather on the demand for electricity. Heating and cooling degree-days provide cumulative variances in the average daily temperature from a baseline of 65 degrees, over a period of time, to indicate the extent to which customers are likely to use, or have used, electricity for heating or air conditioning. The higher the number of degree-days, the greater the expected demand for heating or cooling.

The following table indicates the heating and cooling degree-days for the most recent three-year period, along with 15-year averages for the most recent year provided by the National Weather Service, as measured at Portland International Airport:

	Heating Degree-Days	Cooling Degree-Days
2013	4,386	539
2012	4,169	436
2011	4,650	362
15-year average for 2013	4,239	454

PGE's all-time high net system load peak of 4,073 megawatts (MW) occurred in December 1998. The Company's all-time "summer peak" of 3,949 MW occurred in July 2009. The following table presents the Company's average winter (consisting of January, February and December) and summer (consisting of July, August and September) loads for the periods indicated along with the corresponding peak load and month in which it occurred (in MWs):

	Winter Loads			Summer Loads		
	Average	**Peak**	**Month**	**Average**	**Peak**	**Month**
2013	2,656	3,869	December	2,278	3,527	July
2012	2,529	3,426	January	2,249	3,597	August
2011	2,612	3,555	January	2,233	3,340	September

The Company tracks and evaluates both load growth and peak load requirements for purposes of long-term load forecasting and integrated resource planning, as well as for preparing general rate case assumptions. Behavior patterns, conservation, energy efficiency initiatives and measures, weather effects, economic conditions, and demographic changes all play a role in determining expected future customer demand and the resulting resources the Company will need to adequately meet those loads and maintain adequate capacity reserves.

Power Supply

PGE relies upon its generating resources as well as short- and long-term power and fuel purchase contracts to meet its customers' energy requirements. The Company executes economic dispatch decisions concerning its own generation, and participates in the wholesale market as a result of those economic dispatch decisions, in an effort to obtain reasonably-priced power for its retail customers, manage risk, and administer its current long-term wholesale contracts. The Company also promotes energy efficiency measures to meet its energy requirements.

PGE's generating resources consist of five thermal plants (natural gas- and coal-fired turbines), seven hydroelectric plants, and a wind farm located at Biglow Canyon in eastern Oregon. The volume of electricity the Company generates is dependent upon, among other factors, the capacity and availability of its generating resources. Capacity of the thermal plants represents the MW the plant is capable of generating under normal operating conditions, net of electricity used in the operation of the plant. The capacity of the Company's thermal generating resources is also affected by ambient temperatures. Capacity of both hydro and wind generating resources represent the nameplate MW, which varies from actual energy expected to be received as these types of generating resources are highly dependent upon river flows and wind conditions, respectively. Availability represents the percentage of the year the plant was available for operations, which reflects the impact of planned and forced outages. For a complete listing of these facilities, see "*Generating Facilities*" in Item 2.—"Properties."

PGE's resource capacity (in MW) was as follows:

	As of December 31,					
	2013		2012		2011	
	Capacity	%	Capacity	%	Capacity	%
Generation:						
Thermal:						
Natural gas	1,163	27%	1,172	28%	1,172	28%
Coal	756	17	670	16	670	16
Total thermal	1,919	44	1,842	44	1,842	44
Hydro (1)	501	11	489	12	489	12
Wind (2)	450	10	450	11	450	11
Total generation	2,870	65	2,781	67	2,781	67
Purchased power:						
Long-term contracts:						
Capacity/exchange	160	3	160	4	190	4
Hydro	603	14	588	14	579	14
Wind	39	1	39	1	38	1
Solar	13	—	13	—	6	—
Other	117	3	117	3	110	3
Total long-term contracts	932	21	917	22	923	22
Short-term contracts	596	14	475	11	458	11
Total purchased power	1,528	35	1,392	33	1,381	33
Total resource capacity	4,398	100%	4,173	100%	4,162	100%

(1) Capacity represents nameplate and differs from expected energy to be generated, which is expected to range from 200 MWa to 250 MWa, dependent upon river flows.

(2) Capacity represents nameplate and differs from expected energy to be generated, which is expected to range from 135 MWa to 180 MWa, dependent upon wind conditions.

For information regarding actual generating output and purchases for the years ended December 31, 2013, 2012 and 2011, see the Results of Operations section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Generation

The portion of PGE's retail load requirements generated by its plants varies from year to year and is determined by various factors, including planned and forced outages, availability and price of coal and natural gas, precipitation and snow-pack levels, the market price of electricity, and wind variability. As of December 31, 2013, the Company has new energy and capacity resources under construction, which are expected to be placed in service between 2015 and 2016. Such resources were selected pursuant to the competitive bidding process completed in 2013 in accordance with the Company's 2009 IRP. For additional information on these new energy and capacity resources see "*Capital Requirements*" in the Liquidity and Capital Resources section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Thermal On December 31, 2013, PGE acquired an additional 15% ownership interest in the Boardman coal-fired generating plant (Boardman), which it operates, increasing the Company's ownership share to 80% from 65%. For additional information, see Note 17, Jointly-owned Plant, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data." The Company also has a 20% ownership interest in Colstrip Units 3 and 4 coal-fired generating plant (Colstrip), which is operated by a third party.

These two coal-fired generating facilities provided approximately 22% of the Company's total retail load requirement in 2013, compared with 19% in 2012 and 21% in 2011. The Company's three natural gas-fired generating facilities, Port Westward, Beaver, and Coyote Springs Unit 1 (Coyote Springs), provided approximately 18% of its total retail load requirement in 2013, compared with 15% in 2012 and 11% in 2011.

The thermal plants provide reliable power for the Company's customers and capacity reserves. These resources have a combined capacity of 1,919 MW, representing approximately 67% of the net capacity of PGE's generating facilities. Thermal plant availability, excluding Colstrip, was 84% in 2013, compared with 92% in 2012 and 90% in 2011, while Colstrip plant availability was 66% in 2013, compared with 93% in 2012 and 84% in 2011. Thermal plant availability percentages for 2013 were lower than 2012 and 2011 due to unplanned outages at three plants. For additional information on the unplanned plant outages, see "*Power Operations*" in the Overview section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Hydro The Company's FERC-licensed hydroelectric projects consist of Pelton/Round Butte on the Deschutes River near Madras, Oregon (discussed below), four plants on the Clackamas River, and one on the Willamette River. The licenses for these projects expire at various dates ranging from 2035 to 2055. Although these plants have a combined capacity of 501 MW, actual energy received is dependent upon river flows. Energy from these resources provided 9% of the Company's total retail load requirement in 2013, compared with 10% in 2012 and in 2011, with availability of 100% in 2013, compared with 99% in 2012 and 100% in 2011. Northwest hydro conditions have a significant impact on the region's power supply, with water conditions significantly impacting PGE's cost of power and its ability to economically displace more expensive thermal generation and spot market power purchases.

PGE has a 66.67% ownership interest in the 465 MW Pelton/Round Butte hydroelectric project on the Deschutes River, with the remaining interest held by the Confederated Tribes of the Warm Springs Reservation of Oregon (Tribes). A 50-year joint license for the project, which is operated by PGE, was issued by the FERC in 2005. The Tribes have an option to purchase an additional undivided 16.66% interest in Pelton/Round Butte at its discretion on or after December 31, 2021. The Tribes have a second option to purchase an undivided 0.02% interest in Pelton/Round Butte at its discretion on or after April 1, 2041. If both options are exercised by the Tribes, the Tribes' ownership percentage would exceed 50%.

Wind Biglow Canyon Wind Farm (Biglow Canyon), located in Sherman County, Oregon, is PGE's largest renewable energy resource with 217 wind turbines with a total nameplate capacity of approximately 450 MW. It was completed and placed in service in three phases between December 2007 and August 2010. The energy from Biglow Canyon provided 6% of the Company's total retail load requirement in 2013, 2012, and 2011. Availability for Biglow Canyon was 98% in 2013 and in 2012, and 97% in 2011. The expected energy from wind resources differs from the nameplate capacity and is expected to range from 135 MWa to 180 MWa for Biglow Canyon, dependent upon wind conditions.

Dispatchable Standby Generation (DSG)—PGE has a DSG program under which the Company can start, operate, and monitor customer-owned diesel-fueled standby generators when needed to support specific capacity needs. The program also helps provide NERC-required operating reserves. As of December 31, 2013, there were 49 projects with a total capacity of 93 MW. Additional DSG projects are being pursued with a goal of 100 MW online by the end of 2014.

Fuel Supply—PGE contracts for natural gas and coal supplies required to fuel the Company's thermal generating plants, with certain plants also able to operate on fuel oil if needed. In addition, the Company uses forward, future, swap, and option contracts to manage its exposure to volatility in natural gas prices.

Coal

Boardman—PGE has fixed-price purchase agreements that will provide coal for Boardman for the majority of 2014. The coal is obtained from surface mining operations in Wyoming and Montana and is delivered by rail under two separate transportation contracts which extend through 2020.

PGE expects to begin seeking requests for proposal in 2014 for the purchase of coal to fill remaining open positions for 2014, and to start layering open positions for 2015 and beyond. The terms of contracts and the quality of coal are expected to be staged in alignment with required emissions limits. PGE believes that sufficient market supplies of coal are available to meet anticipated operations of Boardman through 2020.

Natural Gas

Port Westward and Beaver—PGE manages the price risk of natural gas supply for Port Westward through financial contracts up to 60 months in advance. Physical supplies for Port Westward and Beaver are generally purchased within 12 months of delivery and based on anticipated operation of the plants. PGE owns 79.5%, and is the operator of record, of the Kelso-Beaver Pipeline, which directly connects both generating plants to the Northwest Pipeline, an interstate natural gas pipeline operating between British Columbia and New Mexico. Currently, PGE transports gas on the Kelso-Beaver Pipeline for its own use under a firm transportation service agreement, with capacity offered to others on an interruptible basis to the extent not utilized by the Company. PGE has access to 103,305 Dth per day of firm gas transportation capacity to serve the two plants.

PGE also has contractual access through April 2017 to natural gas storage in Mist, Oregon, from which it can draw in the event that gas supplies are interrupted or if economic factors require its use. This storage may be used to fuel both Port Westward and Beaver. PGE believes that sufficient market supplies of gas are available to meet anticipated operations of both plants for the foreseeable future.

Beaver has the capability to operate on No. 2 diesel fuel oil when it is economical or if the plant's natural gas supply is interrupted. PGE had an approximate 6-day supply of ultra-low sulfur diesel fuel oil at the plant site as of December 31, 2013. The current operating permit for Beaver limits the number of gallons of fuel oil that can be burned daily, which effectively limits the daily hours of operation of Beaver on fuel oil.

Coyote Springs—PGE manages the price risk of natural gas supply for Coyote Springs through financial contracts up to 60 months in advance, while physical supplies are generally purchased within 12 months of delivery and based on anticipated operation of the plant. Coyote Springs utilizes 41,000 Dth per day of natural gas when operating at full capacity, with firm transportation capacity on three pipeline systems accessing gas fields in Alberta, Canada. PGE believes that sufficient market supplies of gas are available for Coyote Springs for the foreseeable future, based on anticipated operation of the plant. Although Coyote Springs was designed to also operate on fuel oil, such capability has been deactivated in order to optimize natural gas operations.

Purchased Power

PGE supplements its own generation with power purchased in the wholesale market to meet its retail load requirements. The Company utilizes short- and long-term wholesale power purchase contracts in an effort to provide the most favorable economic mix on a variable cost basis. Such contracts have original terms ranging from one month to 53 years and expire at varying dates through 2055.

PGE's medium term power cost strategy helps mitigate the effect of price volatility on its customers due to changing energy market conditions. The strategy allows the Company to take positions in power and fuel markets up to five years in advance of physical delivery. By purchasing a portion of anticipated energy needs for future years over an extended period, PGE mitigates a portion of the potential future volatility in the average cost of purchased power and fuel.

The Company's major power purchase contracts consist of the following (also see the preceding table which summarizes the average resource capabilities related to these contracts):

Capacity/exchange—PGE has two contracts that provide PGE with firm capacity to help meet the Company's peak loads. The contract representing 10 MW of capacity expires in May 2014 and the contract representing 150 MW of capacity expires in December 2016. In addition to PGE's capacity/exchange power purchase contracts presented in the preceding table, the Company entered into two power purchase agreements for up to 100 MW of seasonal peaking capacity pursuant to the competitive bidding process completed in 2013. One agreement covers winter from December 2014 to February 2019 and the second agreement covers summer from July 2014 to September 2018.

Hydro—The Company has four contracts that provide for the purchase of power generated from hydroelectric projects with an aggregate capacity of 117 MW and which expire between 2015 and 2018. In addition, PGE has the following:

- *Mid-Columbia hydro*—PGE has long-term power purchase contracts with certain public utility districts in the state of Washington for a portion of the output of three hydroelectric projects on the mid-Columbia River. The contract representing 163 MW of capacity expires in 2018 and the contract representing 168 MW of capacity expires in 2052. Although the projects currently provide a total of 331 MW of capacity, actual energy received is dependent upon river flows.

- *Confederated Tribes*—PGE has a long-term agreement under which the Company purchases, at market prices, the Tribes' interest in the output of the Pelton/Round Butte hydroelectric project. Although the agreement provides 155 MW of capacity, actual energy received is dependent upon river flows. The term of the agreement coincides with the term of the FERC license for this project, which expires in 2055. The Tribes may elect to sell its output to another party with a one year notice to PGE.

Wind—PGE has three contracts that provide for the purchase of renewable wind-generated electricity and which extend to various dates between 2028 and 2035. Although these contracts provide a total of 39 MW of capacity, actual energy received is dependent upon wind conditions.

Solar—PGE has three agreements to purchase power generated from photovoltaic solar projects, which expire between 2036 and 2037. These projects have a combined generating capacity of 7 MW. In addition, the Company operates, and purchases power from four solar projects with an aggregate of approximately 6 MW of capacity.

Other—These primarily consist of long-term contracts to purchase power from various counterparties, including other Pacific Northwest utilities, over terms extending into 2031.

Short-term contracts—These contracts are for delivery periods of one month up to one year in length. They are entered into with various counterparties to provide additional firm energy to help meet the Company's load requirement.

PGE also utilizes spot purchases of power in the open market to secure the energy required to serve its retail customers. Such purchases are made under contracts that range in duration from 30 minutes to less than one month. For additional information regarding PGE's power purchase contracts, see Note 15, Commitments and Guarantees, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Future Energy Resource Strategy

PGE is in the process of finalizing its next IRP (2013 IRP), which outlines the Company's expectations for resource needs and resource portfolio performance over the next 20 years. The 2013 IRP is expected to be filed with the OPUC by the end of March 2014. The 2013 IRP also includes an "Action Plan," which covers the Company's proposed actions over the next five years (2014 through 2018). Over this time period, PGE projects energy requirements to approximate, or slightly exceed, the energy available through its generation resources and long-term power purchase agreements. The Company believes that any shortfalls will be manageable through its wholesale purchasing strategy.

Based on PGE's current draft of the 2013 IRP, which was provided to the OPUC Staff in November 2013, the proposed Action Plan includes the following, among other components, between 2014 and 2017:

- Seek renewal, or partial renewal, of expiring power purchase agreements for energy generated from hydroelectric projects, if available and cost-effective for our customers;
- Acquisition of a total of 124 MWa of energy efficiency through continuation of Energy Trust of Oregon programs;
- To help manage peak load conditions and other supply contingencies, acquisition of 55 MW of demand response and PGE dispatchable standby generation from our customers;
- In preparation for the next IRP, perform various research and studies related to load forecast and energy efficiency projections, distributed PV solar application within PGE's service territory, the viability of large-scale biomass operations, fuel supply, wind integration needs, and operational flexibility requirements; and
- Retain and acquire transmission service through Bonneville Power Administration's (BPA's) OATT to interconnect new and existing resources in eastern Oregon to PGE's service territory.

The draft 2013 IRP also incorporates the selected energy and capacity resources resulting from the outcome of the competitive bidding process in 2013 pursuant to the Company's 2009 IRP, the most recent IRP acknowledged by the OPUC. These new resources are currently under construction and are expected to be in service between 2015 and 2016. For additional information on these capital projects see "*Capital Requirements*" in the Liquidity and Capital Resources section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Beyond 2018, PGE projects it will need to procure new resources in order to meet the 2020 and 2025 RPS requirements and to replace energy from Boardman, which is scheduled to cease coal-fired operations in 2020. Additional post-2018 actions may also be needed to offset expiring power purchase agreements and to back-up variable energy resources, such as wind generation facilities. These actions are expected to be identified in a future IRP.

Transmission and Distribution

Transmission systems deliver energy from generating facilities to distribution systems for final delivery to customers. PGE schedules energy deliveries over its transmission system in accordance with FERC requirements and operates one balancing authority area (an electric system bounded by interchange metering) in its service territory. In 2013, PGE delivered approximately 22 million megawatt hours (MWh) in its balancing authority area through 1,141 circuit miles of transmission lines operating at or above 115 kV.

PGE's transmission system is part of the Western Interconnection, the regional grid in the western United States. The Western Interconnection includes the interconnected transmission systems of 11 western states, two Canadian provinces and parts of Mexico, and is subject to the reliability rules of the WECC and the NERC. PGE relies on transmission contracts with BPA to transmit a significant amount of the Company's generation to its distribution system. PGE's transmission system, together with contractual rights on other transmission systems, enables the Company to integrate and access generation resources to meet its customers' energy requirements. PGE's generation is managed on a coordinated basis to obtain maximum load-carrying capability and efficiency. The Company's transmission and distribution systems are located as follows:

- On property owned or leased by PGE;
- Under or over streets, alleys, highways and other public places, the public domain and national forests, and state lands under franchises, easements or other rights that are generally subject to termination;
- Under or over private property as a result of easements obtained primarily from the record holder of title; or
- Under or over Native American reservations under grant of easement by the Secretary of the Interior or lease or easement by Native American tribes.

The Company's wholesale transmission activities are regulated by the FERC and are offered on a non-discriminatory basis, with all potential customers provided equal access to PGE's transmission system in accordance with FERC Standards of Conduct. In accordance with its OATT, PGE offers several transmission services to wholesale customers:

- Network integration transmission service, a service that integrates generating resources to serve retail loads;
- Short- and long-term firm point-to-point transmission service, a service with fixed delivery and receipt points; and
- Non-firm point-to-point service, an "as available" service with fixed delivery and receipt points.

PGE continues to meet state regulatory requirements related to power distribution service quality and reliability. Such requirements are reflected in specific indices that measure outage duration, outage frequency, and momentary power interruptions. The Company is required to include performance results related to service quality measures in annual reports filed with the OPUC. Specific monetary penalties can be assessed for failure to attain required performance levels, with amounts dependent upon the extent to which actual results fail to meet such requirements.

For additional information regarding the Company's transmission and distribution facilities, see "*Transmission and Distribution*" in Item 2.—"Properties."

Environmental Matters

PGE's operations are subject to a wide range of environmental protection laws and regulations, which pertain to air and water quality, endangered species and wildlife protection, and hazardous material. Various state and federal agencies regulate environmental matters that relate to the siting, construction, and operation of generation, transmission, and substation facilities and the handling, accumulation, cleanup, and disposal of toxic and hazardous substances. In addition, certain of the Company's hydroelectric projects and transmission facilities are located on property under the jurisdiction of federal and state agencies, and/or tribal entities that have authority in environmental protection matters. The following discussion provides further information on certain regulations that affect the Company's operations and facilities.

Air Quality

Clean Air Act—PGE's operations, primarily its thermal generating plants, are subject to regulation under the federal Clean Air Act (CAA), which addresses, among other things, particulate matter, hazardous air pollutants, and greenhouse gas emissions (GHGs). Oregon and Montana, the states in which PGE's thermal facilities are located, also implement and administer certain portions of the CAA and have set standards that are at least equal to federal standards.

The United States Environmental Protection Agency (EPA) has issued emissions limits under the CAA National Emission Standards for Hazardous Air Pollutants (NESHAP) to regulate hazardous air emissions from coal and oil fired electric generating units. Emissions limits included in the NESHAP are based on the application of maximum achievable control technology (MACT). Installation of emissions controls to meet the emissions limits for sulfur dioxide (SO_2) and nitrous oxide at Boardman, which include a Dry Sorbent Injection system, was completed in 2013. With the addition of these controls, the Company believes the Boardman plant should meet the MACT requirements without additional capital investment. Oregon Department of Environmental Quality (DEQ) rules provide for coal-fired operation at Boardman to cease no later than December 31, 2020.

Emissions controls in place at Colstrip allow operation within the standards necessary to meet the MACT requirements. The Company does not anticipate further capital investment to meet the requirements currently in place.

Although regulation of mercury emissions is contemplated under NESHAP, the states of Oregon and Montana have previously adopted regulations concerning mercury emissions. Both Boardman and Colstrip meet the mercury compliance requirements in their respective states.

PGE manages its air emissions by the use of low sulfur fuel, emissions and combustion controls and monitoring, and SO_2 allowances awarded under the CAA. The current allowance inventory and expected future annual SO_2 allowances, along with the recent and planned installation of emissions controls, are anticipated to be sufficient to permit the Company to continue to meet its compliance requirements and operate its thermal generating plants at forecasted capacity for at least the next several years.

Climate Change—No comprehensive GHG emissions legislation has been considered and voted on by Congress in recent years. However, state, regional, and federal legislative efforts continue with respect to establishing regulation of GHG emissions and their potential impacts on climate change. Currently, the EPA has taken the lead role on climate change policy utilizing existing authority under the CAA to develop regulations. Areas of focus for the Company include the following:

- In December 2010, the EPA announced a proposed settlement agreement with states and environmental groups that would require the EPA to set GHG New Source Performance Standards (NSPS) for new and modified fossil fuel-based power plants, and guidelines for state-developed NSPS for existing sources. The emissions standards for new natural gas- and coal-fired electric generating units were proposed in April 2012 under the CAA, but have yet to be finalized, as the EPA is in the process of issuing a revised proposal. The EPA has also been directed to propose emissions standards under the CAA for existing fossil fuel-based power plants by June 2014 and issue a final rule one year later. It is expected that individual states will have flexibility that would allow for an array of tools, including RPS and cap and trade programs, to be used to comply with new standards. The Company continues to monitor the developments around the federal proposals.

- The State of Oregon established a non-binding policy guideline that sets a goal to reduce GHG emissions to 10% below 1990 levels by 2020 and at least 75% below 1990 levels by 2050. Although the guideline does not mandate reductions by any specific entity nor include penalties for failure to meet the goal, the Company is required to report to the DEQ the amount of GHG emissions produced along with the total amount of energy produced or purchased by PGE for consumption in Oregon.

Any laws that would impose emissions taxes or mandatory reductions in GHG emissions may have a material impact on PGE's operations, as the Company utilizes fossil fuels in its own power generation and other companies use such fuels to generate power that PGE purchases in the wholesale market. PGE's natural gas-fired facilities, Beaver, Coyote Springs, and Port Westward, and the Company's ownership interest in coal-fired facilities, Boardman and Colstrip, provided approximately 67% of the Company's net generating capacity during 2013. If PGE were to incur incremental costs as a result of changes in the regulations regarding GHGs, the Company would seek recovery in customer prices.

Water Quality

The federal Clean Water Act requires that any federal license or permit to conduct an activity that may result in a discharge to waters of the United States must first receive a water quality certification from the state in which the activity will occur. In Oregon, Montana, and Washington, the Departments of Environmental Quality are responsible for reviewing proposed projects under this requirement to ensure that federally approved activities will meet water quality standards and policies established by the respective state. PGE has obtained permits where required, and has certificates of compliance for its hydroelectric operations under the FERC licenses.

Threatened and Endangered Species and Wildlife

Fish Protection—The federal Endangered Species Act (ESA) has granted protection to many populations of migratory fish species in the Pacific Northwest that have declined significantly over the last several decades. Long-term recovery plans for these species have caused major operational changes to many of the region's hydroelectric projects. PGE purchases power in the wholesale market to serve its retail load requirements and has contracts to purchase power generated at some of the affected facilities on the mid-Columbia River in central Washington.

PGE continues to implement fish protection measures at its hydroelectric projects on the Clackamas, Deschutes, and Willamette rivers that were prescribed by the U.S. Fish and Wildlife Service and the National Marine Fisheries Service under their authority granted in the ESA and the Federal Power Act. As a result of measures contained in their operating licenses, the Deschutes River and Willamette River projects have been certified as low impact hydro, with 50 MWa of their output included as part of the Company's renewable energy portfolio used to meet the requirements of the Oregon RPS. Conditions required with the operating licenses are expected to result in a minor reduction in power production and increase capital spending to modify the facilities to enhance fish passage and survival.

Avian Protection—Various statutory authorities as well as the Migratory Bird Treaty Act have established civil, criminal, and administrative penalties for the unauthorized take of migratory birds. Because PGE operates electric transmission lines and wind generation facilities that can pose risks to a variety of such birds, the Company is required to have an avian protection plan to reduce risks to bird species that can result from Company operations. PGE has developed and implemented such a plan for its transmission and distribution facilities and continues to develop similar plans for its wind generation facilities. In 2014, the avian protection plan is expected to be finalized for Biglow Canyon, while data collection will occur at Tucannon River with a plan expected in 2015.

Hazardous Waste

PGE has a comprehensive program to comply with requirements of both federal and state regulations related to hazardous waste storage, handling, and disposal. The handling and disposal of hazardous waste from Company facilities is subject to regulation under the federal Resource Conservation and Recovery Act (RCRA). In addition, the use, disposal, and clean-up of polychlorinated biphenyls, contained in certain electrical equipment, are regulated under the federal Toxic Substances Control Act.

Boardman and Colstrip produce coal combustion byproducts (CCBs), which have historically not been considered hazardous waste under the RCRA. The EPA continues to consider listing these residuals as hazardous waste, which would likely have an impact on current disposal practices and could increase the Company's cost of handling these materials. The EPA is expected to issue a proposed rulemaking by the end of 2014. The Company cannot predict the possible impact of this matter until the EPA provides further guidance on the proposed rules. If PGE were to incur incremental costs as a result of changes in the regulations, the Company would seek recovery in customer prices.

PGE is also subject to regulation under the Comprehensive Environmental Response Compensation and Liability Act (CERCLA), commonly referred to as Superfund. The CERCLA provides authority to the EPA to assert joint and several liability for investigation and remediation costs for designated Superfund sites.

A 1997 investigation by the EPA of a segment of the Willamette River known as Portland Harbor revealed significant contamination of river sediments and prompted the EPA to subsequently include Portland Harbor on the federal National Priority List as a Superfund site pursuant to CERCLA. The EPA initially listed sixty-nine Potentially Responsible Parties (PRPs), including PGE as it has historically owned or operated property near the river. In 2008, the EPA requested further information from various parties, including PGE, concerning property several miles beyond the original river segment and, as a result, the PRPs now number over one hundred. In March 2012, a draft feasibility study was submitted to the EPA for review and approval. A Record of Decision is expected from the EPA in 2015 on the various clean-up alternatives, which, as outlined in the draft feasibility study, could take up to 28 years to complete and range in cost from $169 million to $1.8 billion. It is unclear for what portion, if any, that PGE might be held responsible.

For additional information on this EPA action, see Note 18, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Under the Nuclear Waste Policy Act of 1982, the USDOE is responsible for the permanent storage and disposal of spent nuclear fuel. PGE has contracted with the USDOE for permanent disposal of spent nuclear fuel from Trojan that is stored in the Independent Spent Fuel Storage Installation (ISFSI), an NRC-licensed interim dry storage facility that houses the fuel at the former plant site. The spent nuclear fuel is expected to remain in the ISFSI until permanent off-site storage is available, which is not likely to be before 2020. Shipment of the spent nuclear fuel from the ISFSI to off-site storage is not expected to be completed prior to 2033. For additional information regarding this matter, see "*Trojan decommissioning activities*" in Note 7, Asset Retirement Obligations, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

ITEM 1A. RISK FACTORS.

Certain risks and uncertainties that could have a significant impact on PGE's business, financial condition, results of operations or cash flows, or that may cause the Company's actual results to vary materially from the forward-looking statements contained in this Annual Report on Form 10-K, include those set forth below.

Recovery of PGE's costs is subject to regulatory review and approval, and the inability to recover costs may adversely affect the Company's results of operations.

The prices that PGE charges for its retail services, as authorized by the OPUC, are a major factor in determining the Company's operating income, financial position, liquidity, and credit ratings. As a general matter, PGE seeks to recover in customer prices most of the costs incurred in connection with the operation of its business, including, among other things, costs related to capital projects (such as the construction of new facilities or the modification of existing facilities), the costs of compliance with legislative and regulatory requirements and the costs of damage from storms and other natural disasters. However, there can be no assurance that such recovery will be granted. The OPUC has the authority to disallow the recovery of any costs that it considers imprudently incurred. Although the OPUC is required to establish customer prices that are fair, just and reasonable, it has significant discretion in the interpretation of this standard.

In February 2014, PGE filed with the OPUC a 2015 General Rate Case with a 2015 test year. For additional information regarding the 2015 General Rate Case, see the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations." In PGE's three most recent general rate cases (2014, 2011 and 2009), overall price increases approved by the OPUC were less than the Company's initial proposals. Under such circumstances, PGE attempts to manage its costs at levels consistent with the reduced price increases. However, if the Company is unable to do so, or if such cost management results in increased operational risk, the Company's financial and operating results could be adversely affected.

Economic conditions that result in reduced demand for electricity and impair the financial stability of some of PGE's customers, could affect the Company's results of operations.

Unfavorable economic conditions in Oregon may result in reduced demand for electricity. Such reductions in demand could adversely affect PGE's results of operations and cash flows. Economic conditions could also result in an increased level of uncollectible customer accounts and cause the Company's vendors and service providers to experience cash flow problems and be unable to perform under existing or future contracts.

Market prices for power and natural gas are subject to forces that are often not predictable and which can result in price volatility and general market disruption, adversely affecting PGE's costs and ability to manage its energy portfolio and procure required energy supply, which ultimately could have an adverse effect on the Company's liquidity and results of operations.

As part of its normal business operations, PGE purchases power and natural gas in the open market under short and long term contracts, which may specify variable-prices or volumes. Market prices for power and natural gas are influenced primarily by factors related to supply and demand. These factors generally include the adequacy of generating capacity, scheduled and unscheduled outages of generating facilities, hydroelectric and wind generation levels, prices and availability of fuel sources for generation, disruptions or constraints to transmission facilities, weather conditions, economic growth, and changes in technology.

Volatility in these markets can affect the availability, price and demand for power and natural gas. Disruption in power and natural gas markets could result in a deterioration of market liquidity, increase the risk of counterparty default, affect regulatory and legislative processes in unpredictable ways, affect wholesale power prices, and impair PGE's ability to manage its energy portfolio. Changes in power and natural gas prices can also affect the fair value of derivative instruments and cash requirements to purchase power and natural gas. If power and natural gas prices decrease from those contained in the Company's existing purchased power and natural gas agreements, PGE may be required to provide increased collateral, which could adversely affect the Company's liquidity. Conversely, if power and natural gas prices rise, especially during periods when the Company requires greater-than-expected volumes that must be purchased at market or short-term prices, PGE could incur greater costs than originally estimated.

The risk of volatility in power costs is partially mitigated through the AUT and the PCAM. PGE files an annual AUT with an update of the Company's forecasted net variable power costs (baseline NVPC) to be reflected in customer prices. The PCAM provides a mechanism by which the Company can adjust future customer prices to reflect a portion of the difference between each year's baseline NVPC included in customer prices 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." The PCAM provides for a fixed deadband range of $15 million below, to $30 million above, baseline NVPC. Application of the PCAM requires that PGE absorb certain power cost increases before the Company is allowed to recover any amount from customers. Accordingly, the PCAM is expected to only partially mitigate the potentially adverse financial impacts of forced generating plant outages, reduced hydro and wind availability, interruptions in fuel supplies, and volatile wholesale energy prices.

The effects of weather on electricity usage can adversely affect results of operations.

Weather conditions can adversely affect PGE's revenues and costs, impacting the Company's results of operations. Variations in temperatures can affect customer demand for electricity, with warmer-than-normal winters or cooler-than-normal summers reducing the demand for energy. Weather conditions are the dominant cause of usage variations from normal seasonal patterns, particularly for residential customers. Severe weather can also disrupt energy delivery and damage the Company's transmission and distribution system.

Rapid increases in load requirements resulting from unexpected adverse weather changes, particularly if coupled with transmission constraints, could adversely impact PGE's cost and ability to meet the energy needs of its customers. Conversely, rapid decreases in load requirements could result in the sale of excess energy at depressed market prices.

Forced outages at PGE's generating plants can increase the cost of power required to serve customers because the cost of replacement power purchased in the wholesale market generally exceeds the Company's cost of generation.

Forced outages at the Company's generating plants could result in power costs greater than those included in customer prices. In 2013, the Company experienced forced outages at three of its generating plants, and as a result, incurred incremental replacement power costs of $17 million. As indicated above, application of the Company's PCAM could help mitigate adverse financial impacts of such outages; however, the cost sharing features of the mechanism do not provide full recovery in customer prices. Inability to recover such costs in future prices could have a negative impact on the Company's results of operations.

The construction of new facilities, or modifications to existing facilities, is subject to risks that could result in the disallowance of certain costs for recovery in customer prices or higher operating costs.

PGE's current position as a "short" utility requires that the Company supplement its own generation with wholesale power purchases to meet its retail load requirement. In addition, long-term increases in both the number of customers and demand for energy will require continued expansion and upgrade of PGE's generation, transmission, and distribution systems. Construction of new facilities and modifications to existing facilities could be affected by various factors, including unanticipated delays and cost increases and the failure to obtain, or delay in obtaining, necessary permits from state or federal agencies or tribal entities, which could result in failure to complete the projects and the disallowance of certain costs in the rate determination process. In addition, failure to complete construction projects according to specifications could result in reduced plant efficiency, equipment failure, and plant performance that falls below expected levels, which could increase operating costs.

Adverse changes in PGE’s credit ratings could negatively affect its access to the capital markets and its cost of borrowed funds.

Access to capital markets is important to PGE’s ability to operate its business and complete its capital projects. Credit rating agencies evaluate the Company’s credit ratings on a periodic basis and when certain events occur. A ratings downgrade could increase the interest rates and fees on PGE’s revolving credit facilities and letter of credit facilities, increasing the cost of funding day-to-day working capital requirements, and could also result in higher interest rates on future long-term debt. A ratings downgrade could also restrict the Company’s access to the commercial paper market, a principal source of short-term financing, or result in higher interest costs.

In addition, if Moody’s Investors Service (Moody’s) and/or Standard & Poor’s Ratings Services (S&P) reduce their rating on PGE’s unsecured debt to below investment grade, the Company could be subject to requests by certain wholesale counterparties to post additional performance assurance collateral, which could have an adverse effect on the Company’s liquidity.

PGE is subject to various legal and regulatory proceedings, the outcome of which is uncertain, and resolution unfavorable to PGE could adversely affect the Company’s results of operations, financial condition or cash flows.

From time to time in the normal course of its business, PGE is subject to various regulatory proceedings, lawsuits, claims and other matters, which could result in adverse judgments, settlements, fines, penalties, injunctions, or other relief. These matters are subject to many uncertainties, the ultimate outcome of which management cannot predict. The final resolution of certain matters in which PGE is involved could require that the Company incur expenditures over an extended period of time and in a range of amounts that could have an adverse effect on its cash flows and results of operations. Similarly, the terms of resolution could require the Company to change its business practices and procedures, which could also have an adverse effect on its cash flows, financial position or results of operations.

There are certain pending legal and regulatory proceedings, such as those related to PGE’s recovery of its investment in Trojan, the proceedings related to refunds on wholesale market transactions in the Pacific Northwest and the investigation and any resulting remediation efforts related to the Portland Harbor site, that may have an adverse effect on results of operations and cash flows for future reporting periods. For additional information, see Item 3.—“Legal Proceedings” and Note 18, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.—“Financial Statements and Supplementary Data.”

Reduced river flows and unfavorable wind conditions can adversely affect generation from hydroelectric and wind generating resources. The Company could be required to replace energy expected from these sources with higher cost power from other facilities or with wholesale market purchases, which could have an adverse effect on results of operations.

PGE derives a significant portion of its power supply from its own hydroelectric facilities and through long-term purchase contracts with certain public utility districts in the state of Washington. Regional rainfall and snow pack levels affect river flows and the resulting amount of energy generated by these facilities. Shortfalls in energy expected from low-cost hydroelectric generating resources would require increased energy from the Company’s higher cost thermal generating plants and/or power purchases in the wholesale market, which could have an adverse effect on results of operations.

PGE also derives a portion of its power supply from wind generating resources, for which the output is dependent upon wind conditions. Unfavorable wind conditions could require increased reliance on power from the Company’s thermal generating resources or power purchases in the wholesale market, both of which could have an adverse effect on results of operations.

Although the application of the PCAM could help mitigate adverse financial effects from any decrease in power provided by hydroelectric and wind generating resources, full recovery of any increase in power costs is not assured. Inability to fully recover such costs in future prices could have a negative impact on the Company's results of operations, as well as a reduction in renewable energy credits and loss of production tax credits related to wind generating resources.

Capital and credit market conditions could adversely affect the Company's access to capital, cost of capital, and ability to execute its strategic plan as currently scheduled.

Access to capital and credit markets is important to PGE's ability to operate. The Company expects to issue debt and equity securities, as necessary, to fund its future capital requirements. In addition, contractual commitments and regulatory requirements may limit the Company's ability to delay or terminate certain projects. For additional information concerning PGE's capital requirements, see "*Capital Requirement*s" in the Liquidity and Capital Resources section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

If the capital and credit market conditions in the United States and other parts of the world deteriorate, the Company's future cost of debt and equity capital, as well as access to capital markets, could be adversely affected. In addition, restrictions on PGE's ability to access capital markets could affect its ability to execute its strategic plan.

Legislative or regulatory efforts to reduce greenhouse gas emissions could lead to increased capital and operating costs and have an adverse impact on the Company's results of operations.

Future legislation or regulations could result in limitations on greenhouse gas emissions from the Company's fossil fuel-fired generation facilities. Compliance with any greenhouse gas emissions reduction requirements could require PGE to incur significant expenditures, including those related to carbon capture and sequestration technology, purchase of emission allowances and offsets, fuel switching, and the replacement of high-emitting generation facilities with lower-emitting facilities.

The cost to comply with potential greenhouse gas emissions reduction requirements is subject to significant uncertainties, including those related to: the timing of the implementation of emissions reduction rules; required levels of emissions reductions; requirements with respect to the allocation of emissions allowances; the maturation, regulation and commercialization of carbon capture and sequestration technology; and PGE's compliance alternatives. Although the Company cannot currently estimate the effect of future legislation or regulations on its results of operations, financial condition or cash flows, the costs of compliance with such legislation or regulations could be material.

Under certain circumstances, banks participating in PGE's credit facilities could decline to fund advances requested by the Company or could withdraw from participation in the credit facilities.

PGE currently has unsecured revolving credit facilities with several banks for an aggregate amount of $700 million. These revolving credit facilities provide a primary source of liquidity and may be used to supplement operating cash flow and as backup for commercial paper borrowings.

The revolving credit facilities represent commitments by the participating banks to make loans and, in certain cases, to issue letters of credit. The Company is required to make certain representations to the banks each time it requests an advance under one of the credit facilities. However, in the event certain circumstances occur that could result in a material adverse change in the business, financial condition or results of operations of PGE, the Company may not be able to make such representations, in which case the banks would not be required to lend. PGE is also subject to the risk that one or more of the participating banks may default on their obligation to make loans under the credit facilities.

In addition, it is possible that the Company might not be aware of certain developments at the time it makes such a representation in connection with a request for a loan, which could cause the representation to be untrue at the time made and constitute an event of default. Such a circumstance could result in a loss of the banks' commitments under the credit facilities and, in certain circumstances, the accelerated repayment of any outstanding loan balances.

Measures required to comply with state and federal regulations related to air emissions and water discharges from thermal generating plants could result in increased capital expenditures and operating costs and reduce generating capacity, which could adversely affect the Company's results of operations.

PGE is subject to state and federal requirements concerning air emissions and water discharges from thermal generating plants. For additional information, see the Environmental Matters section in Item 1.—"Business." These requirements could adversely affect the Company's results of operations by requiring (i) the installation of additional air emissions and water discharge controls at PGE's generating plants, which could result in increased capital expenditures and (ii) changes to the Company's operations that could increase operating costs and reduce generating capacity.

Adverse capital market performance could result in reductions in the fair value of benefit plan assets and increase the Company's liabilities related to such plans. Sustained declines in the fair value of the plans' assets could result in significant increases in funding requirements, which could adversely affect PGE's liquidity and results of operations.

Performance of the capital markets affects the value of assets that are held in trust to satisfy future obligations under PGE's defined benefit pension plan. Sustained adverse market performance could result in lower rates of return for these assets than projected by the Company and could increase PGE's funding requirements related to the pension plan. Additionally, changes in interest rates affect PGE's liabilities under the pension plan. As interest rates decrease, the Company's liabilities increase, potentially requiring additional funding.

Performance of the capital markets also affects the fair value of assets that are held in trust to satisfy future obligations under the Company's non-qualified employee benefit plans, which include deferred compensation plans. As changes in the fair value of these assets are recorded in current earnings, decreases can adversely affect the Company's operating results. In addition, such decreases can require that PGE make additional payments to satisfy its obligations under these plans.

For additional information regarding PGE's contribution obligations under its pension and non-qualified benefit plans, see "*Contractual Obligations and Commercial Commitments*" in the Liquidity and Capital Resources section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations," and "*Pension and Other Postretirement Plans*" in Note 10, Employee Benefits, in the Notes to Consolidated Financial Statements in Item 8.— "Financial Statements and Supplementary Data."

Changes in technology may negatively impact the revenues derived from PGE's generation facilities.

A basic premise of PGE's business is that generating electricity at central generation facilities achieves economies of scale and produces electricity at a relatively low price. Many companies and organizations conduct research and development activities to seek improvements in alternative technologies, such as fuel cells, photovoltaic (solar) cells, micro-turbines and other forms of distributed generation. It is possible that advances in such technologies will reduce the cost of alternative methods of electricity production to a level that is equal to or below that of central thermal and wind generation facilities. Such a development could limit the Company's future growth opportunities and limit growth in demand for PGE's electric service.

Failure of PGE's wholesale suppliers to perform their contractual obligations could adversely affect the Company's ability to deliver electricity and increase the Company's costs.

PGE relies on suppliers to deliver natural gas, coal and electricity, in accordance with short- and long-term contracts. Failure of suppliers to comply with such contracts in a timely manner could disrupt the Company's ability to deliver electricity and require PGE to incur additional expenses in order to meet the needs of its customers. In addition, as these contracts expire, the Company could be unable to continue to purchase natural gas, coal or electricity on terms and conditions equivalent to those of existing agreements.

Operational changes required to comply with both existing and new environmental laws related to fish and wildlife could adversely affect PGE's results of operations.

A portion of PGE's total energy requirement is supplied with power generated from hydroelectric and wind generating resources. Operation of these facilities is subject to regulation related to the protection of fish and wildlife. The listing of various plants and species of fish, birds, and other wildlife as threatened or endangered has resulted in significant operational changes to these projects. Salmon recovery plans could include further major operational changes to the region's hydroelectric projects, including those owned by PGE and those from which the Company purchases power under long-term contracts. In addition, laws relating to the protection of migratory birds and other wildlife could impact the development and operation of transmission lines and wind projects. Also, new interpretations of existing laws and regulations could be adopted or become applicable to such facilities, which could further increase required expenditures for salmon recovery and endangered species protection and reduce the availability of hydroelectric or wind generating resources to meet the Company's energy requirements.

PGE could be vulnerable to cyber security attacks, data security breaches or other similar events that could disrupt its operations, require significant expenditures or result in claims against the Company.

In the normal course of business, PGE collects, processes, and retains sensitive and confidential customer and employee information, as well as proprietary business information, and operates systems that directly impact the availability of electric power and the transmission of electric power in its service territory. Despite the security measures in place, the Company's systems, and those of third-party service providers, could be vulnerable to cyber security attacks, data security breaches or other similar events that could disrupt operations or result in the release of sensitive or confidential information. Such events could cause a shutdown of service or expose PGE to liability. In addition, the Company may be required to expend significant capital and other resources to protect against security breaches or to alleviate problems caused by security breaches. PGE maintains insurance coverage against some, but not all, potential losses resulting from these risks. However, insurance may not be adequate to protect the Company against liability in all cases. In addition, PGE is subject to the risk that insurers will dispute or be unable to perform their obligations to the Company.

Storms and other natural disasters could damage the Company's facilities and disrupt delivery of electricity resulting in significant property loss, repair costs, and reduced customer satisfaction.

PGE has exposure to natural disasters that can cause significant damage to its generation, transmission, and distribution facilities. Such events can interrupt the delivery of electricity, increase repair and service restoration expenses, and reduce revenues. Such events, if repeated or prolonged, can also affect customer satisfaction and the level of regulatory oversight. As a regulated utility, the Company is required to provide service to all customers within its service territory and generally has been afforded liability protection against customer claims related to service failures beyond the Company's reasonable control.

The OPUC has authorized the Company to collect $2 million annually from retail customers for such damages and to defer any amount not utilized in the current year. The deferred amount, $6 million as of December 31, 2013, along with the annual collection, would be available to offset potential storm damage costs in future years.

PGE utilizes insurance, when possible, to mitigate the cost of physical loss or damage to the Company's property. As cost effective insurance coverage for transmission and distribution line property (poles and wires) is currently not available, however, the Company would likely seek recovery of large losses to such property through the ratemaking process.

PGE is subject to extensive regulation that affects the Company's operations and costs.

PGE is subject to regulation by the FERC, the OPUC, and by certain federal, state and local authorities under environmental and other laws. Such regulation significantly influences the Company's operating environment and can have an effect on many aspects of its business. Changes to regulations are ongoing, and the Company cannot predict with certainty the future course of such changes or the ultimate effect that they might have on its business. However, changes in regulations could delay or adversely affect business planning and transactions, and substantially increase the Company's costs.

PGE has a workforce with a significant number of employees approaching retirement, which could make it more difficult to maintain the workforce necessary to provide safe and reliable service to customers and meet regulatory requirements.

The Company anticipates higher averages of retirement rates over the next several years and will likely need to replace a significant number of employees in key positions. PGE's ability to successfully implement a workforce succession plan is dependent upon the Company's ability to employ and retain skilled professional and technical workers. Without a skilled workforce, the Company would face greater challenges in providing safe and reliable service to its customers and meeting regulatory requirements, both of which could affect operating results.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES.

PGE's principal property, plant, and equipment are located on land owned by the Company or land under the control of the Company pursuant to existing leases, federal or state licenses, easements or other agreements. In some cases, meters and transformers are located on customer property. PGE leases its corporate headquarters complex, located in Portland, Oregon. The Indenture securing the Company's First Mortgage Bonds (FMBs) constitutes a direct first mortgage lien on substantially all utility property and franchises, other than expressly excepted property.

Generating Facilities

The following are generating facilities owned by PGE as of December 31, 2013:

Facility	Location	Net Capacity [1]	
Wholly-owned:			
Hydro:			
Faraday	Clackamas River	46	MW
North Fork	Clackamas River	58	
Oak Grove	Clackamas River	44	
River Mill	Clackamas River	25	
T.W. Sullivan	Willamette River	18	
Natural Gas/Oil:			
Beaver	Clatskanie, Oregon	516	
Port Westward	Clatskanie, Oregon	402	
Coyote Springs	Boardman, Oregon	245	
Wind:			
Biglow Canyon	Sherman County, Oregon	450	
Jointly-owned [2]:			
Coal:			
Boardman [3]	Boardman, Oregon	460	
Colstrip [4]	Colstrip, Montana	296	
Hydro:			
Pelton [5]	Deschutes River	73	
Round Butte [5]	Deschutes River	237	
Total net capacity		2,870	MW

(1) Represents net capacity of generating unit as demonstrated by actual operating or test experience, net of electricity used in the operation of a given facility. For wind-powered generating facilities, nameplate ratings are used in place of net capacity. A generator's nameplate rating is its full-load capacity under normal operating conditions as defined by the manufacturer.

(2) Reflects PGE's ownership share.

(3) PGE operates Boardman and has an 80% ownership interest, which, on December 31, 2013, increased from 65%. For additional information concerning the Company's acquisition of an additional 15% ownership interest in Boardman, see Note 17, Jointly-owned Plant, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

(4) PPL Montana, LLC operates Colstrip and PGE has a 20% ownership interest.

(5) PGE operates Pelton and Round Butte and has a 66.67% ownership interest.

PGE's hydroelectric projects are operated pursuant to FERC licenses issued under the Federal Power Act. The licenses for the hydroelectric projects on the three different rivers expire as follows: Clackamas River, 2055; Willamette River, 2035; and Deschutes River, 2055.

Transmission and Distribution

PGE owns and/or has contractual rights associated with transmission lines that deliver electricity from its Oregon generation facilities to its distribution system in its service territory and also to the Western Interconnection. As of December 31, 2013, PGE owned an electric transmission system consisting of 1,141 circuit miles as follows: 212 circuit miles of 500 kV line; 382 circuit miles of 230 kV line; and 547 miles of 115 kV line. The Company also has 26,867 circuit miles of primary and secondary distribution lines that deliver electricity to its customers.

The Company also has an ownership interest in the following transmission facilities:

- Approximately 14% of the capacity on the Montana Intertie from the Colstrip plant in Montana to BPA's transmission system; and
- Approximately 20% of the capacity on the Pacific Northwest Intertie, a 4,800 MW transmission facility between John Day, in northern Oregon, and Malin, in southern Oregon near the California border. The Pacific Northwest Intertie is used primarily for the transmission of interstate purchases and sales of electricity among utilities, including PGE.

In addition, the Company has contractual rights to the following transmission capacity:

- Approximately 3,100 MW of firm BPA transmission on BPA's system to PGE's service territory in Oregon; and
- 200 MW of firm BPA transmission from mid-Columbia projects in Washington to the northern end of the Pacific Northwest Intertie, near John Day, Oregon, and 100 MW to the northern end of the Pacific DC Intertie, near Celilo, Oregon.

ITEM 3. LEGAL PROCEEDINGS.

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

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

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

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

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

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

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

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

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

On October 18, 2013, the Oregon Supreme Court accepted plaintiffs' petition seeking review of the February 6, 2013 Oregon Court of Appeals decision. Opening briefs have been filed with oral argument scheduled for 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.

<u>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</u>, 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 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.

ITEM 4. MINE SAFETY DISCLOSURES.

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

PGE's common stock is traded on the New York Stock Exchange (NYSE) under the ticker symbol "POR". As of February 10, 2014, there were 964 holders of record of PGE's common stock and the closing sales price of PGE's common stock on that date was $29.40 per share. The following table sets forth, for the periods indicated, the highest and lowest sales prices of PGE's common stock as reported on the NYSE.

	High	Low	Dividends Declared Per Share
2013			
Fourth Quarter	$ 30.57	$ 27.82	$ 0.275
Third Quarter	33.26	27.57	0.275
Second Quarter	32.91	29.14	0.275
First Quarter	30.53	27.42	0.270
2012			
Fourth Quarter	$ 28.08	$ 24.86	$ 0.270
Third Quarter	27.92	26.57	0.270
Second Quarter	26.94	24.25	0.270
First Quarter	25.62	24.29	0.265

While PGE expects to pay comparable quarterly dividends on its common stock in the future, the declaration of any dividends is at the discretion of the Company's Board of Directors. The amount of any dividend declaration depends upon factors that the Board of Directors deems relevant and may include, but are not limited to, PGE's results of operations and financial condition, future capital expenditures and investments, and applicable regulatory and contractual restrictions.

ITEM 6. SELECTED FINANCIAL DATA.

The following consolidated selected financial data should be read in conjunction with Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations" and Item 8.—"Financial Statements and Supplementary Data."

	Years Ended December 31,				
	2013	2012	2011	2010	2009
	(In millions, except per share amounts)				
Statement of Income Data:					
Revenues, net	$ 1,810	$ 1,805	$ 1,813	$ 1,783	$ 1,804
Gross margin	58%	60%	58%	54%	48%
Income from operations [1]	$ 206	$ 302	$ 309	$ 267	$ 208
Net income [1]	104	140	147	121	89
Net income attributable to Portland General Electric Company [1]	105	141	147	125	95
Earnings per share—basic [1]	1.36	1.87	1.95	1.66	1.31
Earnings per share—diluted [1]	1.35	1.87	1.95	1.66	1.31
Dividends declared per common share	1.095	1.075	1.055	1.035	1.010
Statement of Cash Flows Data:					
Capital expenditures	656	303	300	450	696

(1) The year ended December 31, 2013 includes $52 million of costs expensed related to the Company's Cascade Crossing Transmission Project.

	As of December 31,				
	2013	2012	2011	2010	2009
	(Dollars in millions)				
Balance Sheet Data:					
Total assets	$ 6,101	$ 5,670	$ 5,733	$ 5,491	$ 5,172
Total long-term debt	1,916	1,636	1,735	1,808	1,744
Total Portland General Electric Company shareholders' equity	1,819	1,728	1,663	1,592	1,542
Common equity ratio	48.7%	51.1%	48.6%	46.7%	46.9%

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

Forward-Looking Statements

The information in this report includes statements that are forward-looking within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements include, but are not limited to, statements that relate to expectations, beliefs, plans, assumptions and objectives concerning future and results of operations, business prospects, future loads, the outcome of litigation and regulatory proceedings, future capital expenditures, market conditions, future events or performance and other matters. Words or phrases such as "anticipates," "believes," "estimates," "expects," "intends," "plans," "predicts," "projects," "will likely result," "will continue," "should," or similar expressions are intended to identify such forward-looking statements.

Forward-looking statements are not guarantees of future performance and involve risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed. PGE's expectations, beliefs and projections are expressed in good faith and are believed by PGE to have a reasonable basis including, but not limited to, management's examination of historical operating trends and data contained in records and other data available from third parties, but there can be no assurance that PGE's expectations, beliefs or projections will be achieved or accomplished.

In addition to any assumptions and other factors and matters referred to specifically in connection with such forward-looking statements, factors that could cause actual results or outcomes for PGE to differ materially from those discussed in forward-looking statements include:

- governmental policies and regulatory audits, investigations and actions, including those of the FERC and OPUC with respect to allowed rates of return, financings, electricity pricing and price structures, acquisition and disposal of facilities and other assets, construction and operation of plant facilities, transmission of electricity, recovery of power costs and capital investments, and current or prospective wholesale and retail competition;
- economic conditions that result in decreased demand for electricity, reduced revenue from sales of excess energy during periods of low wholesale market prices, impaired financial stability of vendors and service providers and elevated levels of uncollectible customer accounts;
- the outcome of legal and regulatory proceedings and issues including, but not limited to, the matters described in Note 18, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data" of this Annual Report on Form 10-K;
- unseasonable or extreme weather and other natural phenomena, which could affect customers' demand for power and PGE's ability and cost to procure adequate power and fuel supplies to serve its customers, and could increase the Company's costs to maintain its generating facilities and transmission and distribution systems;
- operational factors affecting PGE's power generating facilities, including forced outages, hydro and wind conditions, and disruption of fuel supply, which may cause the Company to incur repair costs, as well as increased power costs for replacement power;
- the failure to complete capital projects on schedule and within budget or the abandonment of capital projects, which could result in the Company's inability to recover project costs;
- volatility in wholesale power and natural gas prices, which could require PGE to issue additional letters of credit or post additional cash as collateral with counterparties pursuant to existing power and natural gas purchase agreements;
- capital market conditions, including access to capital, interest rate volatility, reductions in demand for investment-grade commercial paper, as well as changes in PGE's credit ratings, which could have an impact on the Company's cost of capital and its ability to access the capital markets to support requirements for working capital, construction of capital projects, and the repayments of maturing debt;

- future laws, regulations, and proceedings that could increase the Company's costs or affect the operations of the Company's thermal generating plants by imposing requirements for additional emissions controls or significant emissions fees or taxes, particularly with respect to coal-fired generating facilities, in order to mitigate carbon dioxide, mercury and other gas emissions;
- changes in wholesale prices for fuels, including natural gas, coal and oil, and the impact of such changes on the Company's power costs;
- changes in the availability and price of wholesale power;
- changes in residential, commercial, and industrial customer growth, and in demographic patterns, in PGE's service territory;
- the effectiveness of PGE's risk management policies and procedures;
- declines in the fair value of securities held for the defined benefit pension plans and other benefit plans, which could result in increased funding requirements for such plans;
- changes in, and compliance with, environmental and endangered species laws and policies;
- the effects of climate change, including changes in the environment that may affect energy costs or consumption, increase the Company's costs, or adversely affect its operations;
- new federal, state, and local laws that could have adverse effects on operating results;
- cyber security attacks, data security breaches, or other malicious acts that cause damage to the Company's generation and transmission facilities or information technology systems, or result in the release of confidential customer and proprietary information;
- employee workforce factors, including a significant number of employees approaching retirement, potential strikes, work stoppages, and transitions in senior management;
- political, economic, and financial market conditions;
- natural disasters and other risks, such as earthquake, flood, drought, lightning, wind, and fire;
- financial or regulatory accounting principles or policies imposed by governing bodies; and
- acts of war or terrorism.

Any forward-looking statement speaks only as of the date on which such statement is made, and, except as required by law, PGE undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time and it is not possible for management to predict all such factors, nor can it assess the impact of any such factor on the business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement.

Overview

Operating Activities—PGE is a vertically integrated electric utility engaged in the generation, transmission, distribution, and retail sale of electricity in the state of Oregon, as well as the wholesale purchase and sale of electricity and natural gas in the United States and Canada. The Company generates revenues and cash flows primarily from the retail sale and distribution of electricity to customers in its service territory.

The Company's revenues and income from operations can fluctuate during the year due to, among other variables, the impacts of seasonal weather conditions on the demand for electricity and changes in retail prices for electricity and in customer usage patterns. In addition, the availability and price of power and fuel can affect income from operations. PGE is a winter-peaking utility that typically experiences its highest retail energy demand during the winter heating season, with a slightly lower peak in the summer that generally results from air conditioning demand.

Customers and Demand—Residential energy deliveries increased 2.6% in 2013 from 2012, reflecting the effects of weather. During 2013, heating and cooling degree-days (indicator of the effect of weather on demand for energy) combined were 7% higher than 2012, when more normal seasonal weather conditions prevailed. Energy deliveries to commercial and industrial customers combined for 2013 were comparable to 2012. Energy efficiency and conservation efforts by retail customers influence demand, although the financial effects of such efforts are intended to be mitigated by the decoupling mechanism.

The following table indicates the average number of retail customers and deliveries, by customer class, during the past two years:

	2013		2012		Increase/ (Decrease) in Energy Deliveries
	Average Number of Customers	Energy Deliveries *	Average Number of Customers	Energy Deliveries *	
Residential	728,481	7,702	723,440	7,505	2.6%
Commercial	104,385	7,441	103,766	7,402	0.5
Industrial	263	4,276	261	4,283	(0.2)
Total	833,129	19,419	827,467	19,190	1.2%

* In thousands of MWh.

Adjusted for the effects of weather, total retail energy deliveries in 2013 were comparable to 2012. PGE projects that retail energy deliveries for 2014 will increase approximately 1% from 2013 weather adjusted levels, after allowing for energy efficiency and conservation efforts.

Power Operations—PGE utilizes a combination of its own generating resources and wholesale market transactions to meet the energy needs of its retail customers. Based on numerous factors, including plant availability, customer demand, river flows, wind conditions, and current wholesale prices, the Company continuously makes economic dispatch decisions in an effort to obtain reasonably-priced power for its retail customers. As a result, the amount of power generated and purchased in the wholesale market to meet the Company's retail load requirement can vary from period to period.

Plant availability is impacted by planned maintenance and forced outages, during which the respective plant is unavailable to provide power. PGE's thermal generating plants require varying levels of annual maintenance, which is generally performed during the second quarter of the year. More extensive planned service maintenance was performed in 2011, compared to 2013 and 2012.

In addition, unplanned plant outages impact the plants' availability and during the second half of 2013, three different plants had unplanned outages ranging from four weeks to six months as follows:

- Colstrip Unit 4 tripped off-line on July 1, 2013 as a result of damage that occurred in the unit's generator. PPL Montana, LLC is the operator of Colstrip Unit 4, of which PGE has a 20% ownership interest representing 148 MW net capacity. Total repair costs are estimated at $30 million, with PGE's share representing $6 million. The majority of the repair costs are expected to be capitalized. The plant came back online in late January 2014.

- Boardman was off-line July 1, 2013 to July 31, 2013 as a result of a thermal water hammer event causing structural damage to the cold reheat piping line that runs between the turbine and the boiler. PGE is the operator of Boardman and had a 65% ownership interest representing 374 MW net capacity at the time of the outage. Total repair costs amounted to $10 million, the majority of which have been capitalized net of $6.7 million of insurance proceeds.

- Coyote Springs was off-line from August 24, 2013 to November 30, 2013 as a result of cracks in the steam turbine rotor. Coyote Springs has a net capacity of 246 MW, which represents approximately 9% of the Company's total net generating capacity. Total repair costs amounted to $2 million, which is included in operating and maintenance expense.

As a result of these unplanned outages, the Company incurred $17 million of incremental power costs to replace its share of the output of these plants over the period of time the plants were off-line in 2013. These incremental replacement power costs are included in actual NVPC in the Company's PCAM calculation for 2013.

Availability of the plants PGE operates approximated 89%, 94%, and 93% for the years ended December 31, 2013, 2012, and 2011, respectively, with the availability of Colstrip, which PGE does not operate, approximating 66%, 93%, and 84%, respectively.

During the year ended December 31, 2013, the Company's generating plants provided approximately 54% of its retail load requirement, compared to 50% in 2012 and 48% in 2011. The lower relative volume of power generated to meet the Company's retail load requirement during 2012 and 2011 was primarily due to the economic displacement of thermal generation by energy received from hydro resources and lower-cost purchased power.

Energy received from PGE-owned hydroelectric plants and under contracts from mid-Columbia hydroelectric projects decreased 11% in 2013 compared to 2012, primarily due to less favorable hydro conditions in 2013. These resources provided approximately 17% of the Company's retail load requirement for 2013, compared with 19% for 2012 and 25% for 2011. Energy received from these sources exceeded projections (or "normal") included in the Company's AUT by approximately 1% in 2013, 11% in 2012, and 13% in 2011. Such projections, which are finalized with the OPUC in November each year, establish the power cost component of retail prices for the following calendar year. "Normal" represents the level of energy forecasted to be received from hydroelectric resources for the year and is based on average regional hydro conditions. Any excess in hydro generation from that projected in the AUT generally displaces power from higher cost sources, while any shortfall is generally replaced with power from higher cost sources. Based on recent forecasts of regional hydro conditions, energy from hydro resources is expected to be below normal for 2014.

Energy expected to be received from wind generating resources is projected annually in the AUT and through 2013, was based on wind studies completed in connection with the permitting process of the wind farm. For 2014 and beyond, the projection included in the AUT will be based on a five-year historical rolling average of the wind farm. To the extent historical information is not available for a given year, the projections will be based on the wind studies. Any excess in wind generation from that projected in the AUT generally displaces power from higher cost sources, while any shortfall is generally replaced with power from higher cost sources. Energy received from wind generating resources fell short of that projected in PGE's AUT by 15% in 2013, 20% in 2012 and 13% in 2011.

Pursuant to the Company's PCAM, customer prices can be adjusted to reflect a portion of the difference between each year's forecasted NVPC included in prices (baseline NVPC) and actual NVPC for the year, to the extent such difference is outside of a pre-determined "deadband," which ranges from $15 million below to $30 million above baseline NVPC. To the extent actual NVPC is above or below the deadband, the PCAM provides for 90% of the variance to be collected from or refunded to customers, respectively, subject to a regulated earnings test. The following is a summary of the impacts of the PCAM for 2013, 2012 and 2011.

- For 2013, actual NVPC was above baseline NVPC by $11 million, which is within the established deadband range. Accordingly, no customer refund or collection 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.

- For 2011, actual NVPC was below baseline NVPC by $34 million, and exceeded the lower deadband threshold of $15 million. PGE recorded an estimated refund to customers of $10 million as of December 31, 2011, reduced from the $17 million potential refund to customers as a result of the regulated earnings test. A final determination regarding the 2011 PCAM results was made by the OPUC through a public filing and review in 2012, which, based upon the application of an updated regulated earnings test, resulted in a revised refund to customers of $6 million, which was returned to customers over a one-year period that began January 1, 2013.

For further information concerning the PCAM see *Power Costs* under "*State of Oregon Regulation*" in the Regulation section of Item 1.—"Business."

General Rate Cases—On December 9, 2013, the OPUC issued an order on PGE's 2014 General Rate Case, which was based on a 2014 test year. The OPUC authorized a $61 million increase in annual revenues, representing an approximate 4% overall increase in customer prices. New customer prices became effective January 1, 2014.

The increase includes improvements to existing power plants and wind forecasting, new Clackamas River fish-sorting facilities, a disaster-preparedness center, technology investments, employee benefit costs and compliance with new federal regulations. In addition, the order approves a capital structure of 50% debt and 50% equity, a return on equity of 9.75%, a cost of capital of 7.65%, and an average rate base of approximately $3.1 billion.

On February 13, 2014, PGE filed with the OPUC a 2015 General Rate Case, which is based on a 2015 test year. PGE requested an $81 million net increase in annual revenues, representing an approximate 4.6% overall increase in customer prices. The net increase in annual revenues consists of the following (in millions):

New generating plants:	
Port Westward Unit 2	$ 51
Tucannon River	47
Base business cost increase	12
Less: customer credits [1]	(29)
Annual revenue net increase	$ 81

(1) Includes approximately $17 million for the return of $50 million over three years, 2015 through 2017, for the settlement of a legal matter concerning costs associated with the operation of the ISFSI at Trojan. Also includes credits related to the return of ISFSI tax credits to customers and additional BPA Regional Power Act refund to residential customers.

PGE is proposing a capital structure of 50% debt and 50% equity, a return on equity of 10%, a cost of capital of 7.78%, and an average rate base of approximately $3.9 billion.

Regulatory review of the 2015 General Rate Case will continue throughout 2014, with a final order expected to be issued by the OPUC by mid-December 2014. New customer prices are expected to become effective in 2015, with the first price increase effective January 1 and two additional price increases effective as two new generating plants become operational, which is expected in the first half of 2015.

Capital Requirements and Financing—During 2013, PGE completed the competitive bidding processes for additional generation resources identified in its 2009 IRP. Pursuant to the request for proposals, one for capacity and energy (baseload) resources and one for renewable resources, the following resources were selected as the successful bids:

- In January, Port Westward Unit 2 (PW2), a flexible 220 MW natural gas-fired generating resource, was selected as the successful bid for the capacity resource;

- In June, Carty Generating Station (Carty), a 440 MW natural gas-fired generating plant, located adjacent to the Company's Boardman plant in eastern Oregon, was selected as the successful bid for the energy (baseload) resource; and

- In June, Tucannon River, a 267 MW wind farm, was selected as the successful bid for the renewable resource.

For additional information on these capital projects, see "*Capital Requirements*" in the Liquidity and Capital Resources section in this Item 7.

More than half of PGE's capital requirements in 2013 related to the construction of these new generation resources, with the remainder related to ongoing capital expenditures for the upgrade, replacement, and expansion of transmission, distribution and generation infrastructure, as well as technology enhancements and expenditures related to hydro licensing. During 2013, the combination of cash from operations in the amount of $544 million, and net proceeds from the issuances of equity and debt instruments in the amount of $67 million and $380 million, respectively, funded the Company's capital requirements of $656 million and contractual maturities of long-term debt of $100 million.

Capital expenditures in 2014 are expected to approximate $1 billion, which includes an estimated $675 million related to the three new generation resources under construction. PGE expects to fund 2014 estimated capital requirements with a combination of cash from operations, which is expected to range from $500 million to $520 million, and issuances of shares pursuant to an equity forward sale agreement (EFSA) and long-term debt securities, which is dependent upon the timing and amount of capital expenditures. For information concerning the EFSA, see Note 12, Equity-based Plans, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data." and for additional related information, see the Liquidity and Debt and Equity Financings sections of this Item 7.

Legal, Regulatory and Environmental Matters—PGE is a party to certain proceedings, the ultimate outcome of which could have a material impact on the results of operations and cash flows in future reporting periods. Such proceedings include, but are not limited to, matters related to:

- Recovery of the Company's investment in its closed Trojan plant;
- Claims for refunds related to wholesale energy sales during 2000 - 2001 in the Pacific Northwest Refund proceeding; and
- An investigation of environmental matters at Portland Harbor.

For additional information regarding the above and other matters, see Note 18, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

The following discussion highlights certain regulatory items, which have impacted the Company's revenues, results of operations, or cash flows for 2013, or have affected customer prices, as authorized by the OPUC. In some cases, the Company deferred the related expenses or benefits as regulatory assets or liabilities, respectively, for later amortization and inclusion in customer prices, pending OPUC review and authorization.

Power Costs—Pursuant to the AUT process, PGE files annually an estimate of power costs for the following year. In the event a general rate case is filed in any given year, forecasted power costs would be included in such filing. The OPUC issued an order on the 2013 AUT resulting in an estimated 2% decrease in customer prices as a result of expected lower power costs. The new prices became effective January 1, 2013 and were expected to result in a decline of approximately $36 million in annual revenues compared to 2012. Actual NVPC for 2013 were $11 million above what was expected in the AUT.

The 2014 AUT was approved by the OPUC and became effective January 1, 2014, with an expected reduction in annual revenues of approximately $17 million based on lower forecasted power costs. This amount is included in the overall $61 million revenue increase authorized by the OPUC in the Company's 2014 General Rate Case.

In June 2013, the Company submitted the 2012 results of the PCAM to the OPUC for final regulatory review and determination of any customer refund or collection. Based on a regulated earnings test, no refund or collection resulted, and in October 2013, the OPUC issued an order to such effect. For further information, see "*Power Operations*" in the Operating Activities section of this Overview, above.

Renewable Resource Costs—Pursuant to a renewable adjustment clause (RAC) mechanism, PGE can recover in customer prices prudently incurred costs of renewable resources that are expected to be placed in service in the current year. The Company may submit a filing to the OPUC by April 1st each year, with prices expected to become effective January 1st of the following year. As part of the RAC, the OPUC has authorized the deferral of eligible costs not yet included in customer prices until the January 1st effective date.

PGE did not submit a RAC filing to the OPUC in 2013 as it did not place renewable resources into service. The Company expects to utilize the RAC to recover certain costs associated with Tucannon River, construction of which began in 2013.

Decoupling Mechanism—The decoupling mechanism, which the OPUC has authorized through 2016, is intended to provide for recovery of margin lost as a result of a reduction in electricity sales attributable to energy efficiency and conservation efforts by residential and certain commercial customers. The mechanism provides for collection from (or refund to) customers if weather adjusted use per customer is less (or more) than that projected in the Company's most recent general rate case.

As part of the Company's 2014 General Rate Case, the OPUC approved a change in the refund or collection period to begin January 1. Collection or refund is expected to occur over a one-year period, which, for the 2013 year, will begin January 1, 2015. The Company recorded an estimated collection of $5 million during the year ended December 31, 2013, which resulted from variances between actual weather adjusted use per customer and that projected in the 2011 General Rate Case.

Capital deferral—In the 2011 General Rate Case, the OPUC authorized the Company to defer the costs associated with four capital projects that were not completed at the time the 2011 General Rate Case was approved. In 2012, PGE recorded a regulatory asset of $16 million for potential recovery in customer prices with an offsetting credit to Depreciation and amortization expense. The OPUC authorized recovery of the deferred costs, with a resulting tariff effective over a one year period beginning January 1, 2014. The Company deferred an additional $18 million of costs associated with these projects during 2013 and plans to file for recovery of these deferred costs, subject to an earnings test, in July 2014 with new customer prices expected to be effective in January 2015.

Boardman Operating Life Adjustment—In PGE's 2011 General Rate Case, the OPUC approved a tariff that provided a mechanism for future consideration of customer price changes related to the recovery of the Company's remaining investment in Boardman over a shortened operating life. Pursuant to the tariff, the OPUC approved recovery of increased depreciation expense reflecting a change in the retirement date of Boardman from 2040 to 2020 and estimated decommissioning costs, with new prices effective July 1, 2011. As part of the 2014 General Rate Case, the incremental depreciation expense that resulted from the shortened Boardman life was rolled into base customer prices, while recovery of the decommissioning costs continue under this separate tariff. The OPUC is currently considering the request for recovery of additional decommissioning costs that resulted from the acquisition of the additional 15% interest in Boardman on December 31, 2013. The tariff also provides for annual updates to decommissioning revenue requirements with revised prices to take effect each January 1.

Results of Operations

The following tables provide financial and operational information to be considered in conjunction with management's discussion and analysis of results of operations.

The consolidated statements of income for the years presented (dollars in millions):

	Years Ended December 31,					
	2013		2012		2011	
	Amount	As % of Rev	Amount	As % of Rev	Amount	As % of Rev
Revenues, net	$ 1,810	100%	$ 1,805	100%	$ 1,813	100%
Purchased power and fuel	757	42	726	40	760	42
Gross margin	1,053	58	1,079	60	1,053	58
Other operating expenses:						
Production and distribution	225	12	211	12	201	11
Cascade Crossing transmission project	52	3	—	—	—	—
Administrative and other	219	12	216	12	218	12
Depreciation and amortization	248	14	248	14	227	13
Taxes other than income taxes	103	6	102	5	98	5
Total other operating expenses	847	47	777	43	744	41
Income from operations	206	11	302	17	309	17
Interest expense, net (1)	101	5	108	6	110	6
Other income:						
Allowance for equity funds used during construction	13	1	6	—	5	—
Miscellaneous income, net	7	—	4	—	1	—
Other income, net	20	1	10	—	6	—
Income before income taxes	125	7	204	11	205	11
Income tax expense	21	1	64	3	58	3
Net income	104	6	140	8	147	8
Less: net loss attributable to noncontrolling interests	(1)	—	(1)	—	—	—
Net income attributable to Portland General Electric Company	$ 105	6%	$ 141	8%	$ 147	8%

(1) Includes an allowance for borrowed funds used during construction of $7 million in 2013, $4 million in 2012, and $3 million in 2011.

Revenues, energy deliveries (based in MWh), and average number of retail customers consist of the following for the years presented:

	Years Ended December 31,					
	2013		2012		2011	
Revenues[1] (dollars in millions):						
Retail:						
Residential	$ 861	48%	$ 860	48%	$ 877	48%
Commercial	619	34	633	34	635	35
Industrial	217	12	226	13	226	13
Subtotal	1,697	94	1,719	95	1,738	96
Other accrued (deferred) revenues, net	(5)	—	4	—	(16)	(1)
Total retail revenues	1,692	94	1,723	95	1,722	95
Wholesale revenues	80	4	49	3	60	3
Other operating revenues	38	2	33	2	31	2
Total revenues	$ 1,810	100%	$ 1,805	100%	$ 1,813	100%
Energy deliveries[2] (MWh in thousands):						
Retail:						
Residential	7,702	35%	7,505	35%	7,733	36%
Commercial	7,441	34	7,402	35	7,419	35
Industrial	4,276	20	4,283	20	4,193	19
Total retail energy deliveries	19,419	89	19,190	90	19,345	90
Wholesale energy deliveries	2,353	11	2,249	10	2,142	10
Total energy deliveries	21,772	100%	21,439	100%	21,487	100%
Average number of retail customers:						
Residential	728,481	87%	723,440	87%	719,977	87%
Commercial	104,385	13	103,766	13	102,940	13
Industrial	263	—	261	—	255	—
Total	833,129	100%	827,467	100%	823,172	100%

(1) Includes both revenues from customers who purchase their energy supplies from the Company and revenues from the delivery of energy to those commercial and industrial customers that purchase their energy from ESSs.
(2) Includes both energy sold to retail customers and energy deliveries to those commercial and industrial customers that purchase their energy from ESSs.

PGE's sources of energy, including total system load and retail load requirement, for the years presented are as follows:

	Years Ended December 31,					
	2013		2012		2011	
Sources of energy (MWh in thousands):						
Generation:						
Thermal:						
Coal	4,070	19%	3,610	17%	4,125	19%
Natural gas	3,375	16	2,882	14	2,138	10
Total thermal	7,445	35	6,492	31	6,263	29
Hydro	1,646	8	1,943	9	1,933	9
Wind	1,200	5	1,125	5	1,216	6
Total generation	10,291	48	9,560	45	9,412	44
Purchased power:						
Term	6,472	31	7,382	35	6,252	29
Hydro	1,629	8	1,728	8	2,897	13
Wind	311	1	319	1	269	1
Spot	2,547	12	2,285	11	2,763	13
Total purchased power	10,959	52	11,714	55	12,181	56
Total system load	21,250	100%	21,274	100%	21,593	100%
Less: wholesale sales	(2,353)		(2,249)		(2,142)	
Retail load requirement	18,897		19,025		19,451	

Net income attributable to Portland General Electric Company for the year ended December 31, 2013 was $105 million, or $1.35 per diluted share, compared to $141 million, or $1.87 per diluted share, for the year ended December 31, 2012. The $36 million, or 26%, decrease in net income was primarily due to the charge to expense in 2013 of $52 million of previously capitalized costs related to Cascade Crossing, $17 million of incremental replacement power costs related to three unplanned plant outages, and an industrial customer refund of $9 million related to cumulative over-billings over a period of several years. These three items are the primary drivers for the reduction in the Company's income tax expense for 2013, which had a favorable impact to net income when compared to 2012. In addition, higher repair costs at the Company's generating plants, higher operating and maintenance costs related to PGE's transmission and distribution system, a 4% increase in average variable power cost per MWh, and higher pension costs all contributed to the decrease in net income. A 3% increase in retail energy deliveries to residential customers primarily resulting from more extreme weather in 2013, an increase in the allowance for debt and equity funds used for construction, as well as lower interest expense partially offset the decreases to net income.

Net income attributable to Portland General Electric Company for the year ended December 31, 2012 was $141 million, or $1.87 per diluted share, compared to $147 million, or $1.95 per diluted share, for the year ended December 31, 2011. The $6 million, or 4%, decrease in net income was primarily driven by the 3% decrease in retail energy deliveries to residential customers, primarily resulting from warmer weather during the heating season, which was partially offset by a 3% decrease in average variable power cost per MWh, which was driven by lower wholesale power and natural gas prices. Actual NVPC was $17 million below the baseline NVPC established in the AUT for 2012, compared to $34 million below the baseline in 2011. In addition, a higher effective income tax rate and increased pension expense contributed to the decrease in net income. Offsetting these decreases was the deferral of $15 million of costs related to four capital projects during 2012.

2013 Compared to 2012

Revenues increased $5 million in 2013 compared with 2012 as a result of the items discussed below.

Total retail revenues decreased $31 million, or 2%, in 2013 compared with 2012, primarily due to the net effect of the following:

- A $38 million decrease resulting from lower average prices due primarily to lower expected power costs as established in the Company's 2013 AUT and a larger portion of energy deliveries going to customers who purchase their energy from ESSs;

- A $9 million decrease related to an industrial customer refund for cumulative over-billings that occurred over a period of several years as a result of a meter configuration error. Management believes the customer billing error is not material to any past reporting period. The Company corrected this matter in the second quarter of 2013 through an out of period adjustment; and

- A $4 million decrease related to the Company's PCAM, as the estimated refund to customers related to the 2011 PCAM was reduced in 2012, with no estimated refund to or collection from customers recorded in 2013; partially offset by

- A $20 million increase related to higher volumes of energy deliveries driven by more extreme weather in 2013 compared to 2012. Residential energy deliveries were up 2.6% in 2013, while commercial and industrial deliveries combined were comparable to 2012.

Both heating and cooling degree-days in 2013 exceeded the 15-year averages (as provided by the National Weather Service, as measured at Portland International Airport), while in 2012, both heating and cooling degree-days fell below the 15-year averages. The following table indicates the number of actual heating and cooling degree-days for the periods presented, along with the 15-year averages:

	Heating Degree-Days			Cooling Degree-Days		
	2013	2012	Increase/ (decrease)	2013	2012	Increase/ (decrease)
1st quarter	1,902	1,967	(3)%	—	—	—%
2nd quarter	593	709	(16)	82	40	105
3rd quarter	90	58	55	457	395	16
4th quarter	1,801	1,435	26	—	1	(100)
	4,386	4,169	5	539	436	24
15-year annual average	4,239	4,235	—	454	456	—
Increase (decrease) from the 15-year annual average	3%	(2)%		19%	(4)%	

On a weather adjusted basis, retail energy deliveries in 2013 were comparable to 2012, with energy deliveries to residential customers increasing by 1%, and energy deliveries to commercial and industrial customers combined were comparable to prior year. PGE projects that retail energy deliveries for 2014 will increase approximately 1% from 2013 weather adjusted levels, after allowing for energy efficiency and conservation efforts.

Wholesale revenues result from sales of electricity to utilities and power marketers that are made in the Company's efforts to secure reasonably priced power for its retail customers, manage risk, and administer its current long-term wholesale contracts. Such sales can vary significantly from year to year as a result of economic conditions, power and fuel prices, hydro and wind availability, and customer demand.

In 2013, the $31 million, or 63%, increase in wholesale revenues from 2012 consisted of $29 million related to a 55% increase in average wholesale price and $2 million related to a 5% increase in wholesale sales volume.

Other operating revenues increased $5 million, or 15%, in 2013 from 2012, primarily due to an increase in gains on the sale of excess natural gas, and an increase in the sale of oil, not needed for operations.

Purchased power and fuel expense includes 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. In 2013, Purchased power and fuel expense increased $31 million, or 4%, from 2012, largely due to a 4% increase in average variable power cost per MWh. Such increase was driven by a 16% increase in the cost of purchased power and a decrease in energy received from hydroelectric projects. In addition, during the second half of 2013, the Company experienced unplanned plant outages at three of its generating facilities and incurred $17 million of incremental replacement power costs. A 10% decrease in the average cost per MWh of power generated partially offset the increases. The average variable power cost increased to $35.61 per MWh in 2013 from $34.25 per MWh in 2012.

Hydroelectric energy, from PGE-owned hydroelectric projects and from mid-Columbia projects combined, decreased 11% during 2013 from 2012 due to less favorable hydro conditions in 2013. In each of 2013 and 2012 total hydroelectric energy received exceeded that projected in the Company's AUT by approximately 1% for 2013 and 11% for 2012. Based on recent forecasts of regional hydro conditions in 2014, energy from hydro resources is expected to be below normal levels.

The following table presents the forecast of the April-to-September 2014 runoff (issued February 12, 2014) compared to the actual runoffs for 2013 and 2012 (as a percentage of normal, as measured over the 30-year period from 1971 through 2000):

	Runoff as a Percent of Normal *		
Location	2014 Forecast	2013 Actual	2012 Actual
Columbia River at The Dalles, Oregon	95%	100%	126%
Mid-Columbia River at Grand Coulee, Washington	97	108	129
Clackamas River at Estacada, Oregon	92	102	133
Deschutes River at Moody, Oregon	96	98	118

* Volumetric water supply forecasts for the Pacific Northwest region are prepared by the Northwest River Forecast Center in conjunction with the Natural Resources Conservation Service and other cooperating agencies.

Energy from PGE-owned wind generating resources (Biglow Canyon) increased 7% from 2012 due to unfavorable wind conditions in 2012, and represented 6% of the Company's retail load requirement in 2013 and in 2012. Energy received from Biglow Canyon fell short of projections included in the Company's AUT by approximately 15% in 2013 compared to 20% in 2012.

Actual NVPC consists of Purchased power and fuel expense net of Wholesale revenues and was comparable for 2013 relative to 2012. A decrease driven by a 55% increase in the average price per MWh of wholesale power sales, was largely offset by a 4% increase in the average variable power cost per MWh. For 2013, actual NVPC was $11 million above baseline NVPC, compared with $17 million below baseline NVPC for 2012.

Production and distribution expense increased $14 million, or 7%, in 2013 compared to 2012. The increase is largely due to $5 million related to planned overhaul and repair costs at Colstrip and Coyote Springs, $3 million related to increased delivery system repair and restoration work, $3 million for the warranty extension related to the third phase of Biglow Canyon, and $2 million of expense associated with the Company's benchmark proposals that were not selected in the RFP process for new generation.

Cascade Crossing transmission project reflects $52 million of costs expensed in the second quarter of 2013, which were previously recorded as construction work-in-progress (CWIP). For additional information, see "*Electric*

Utility Plant" in Note 2, Summary of Significant Accounting Policies, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Administrative and other expense increased $3 million, or 1%, in 2013 compared to 2012, as a $6 million increase in employee pension expense, driven by a lower discount rate, was partially offset by amortization of $3 million in 2012 of deferred costs related to the Trojan refund matter.

Depreciation and amortization expense in 2013 was comparable to 2012, as a $7 million increase resulting from capital additions was largely offset by an increase in costs deferred related to four capital projects as authorized in the Company's 2011 General Rate Case, a decrease in the asset retirement obligation (ARO) resulting from the decommissioning of the Bull Run hydro facility in 2012, and the amortization in 2012 of tax credits related to the ISFSI located at the former Trojan site.

Interest expense decreased $7 million, or 6%, in 2013 compared with 2012, consisting of $4 million related to the timing of the 2013 maturities and issuances of long-term debt, and $3 million related to an increase in the allowance for borrowed funds used for construction, which was driven by a higher average CWIP balance resulting from the commencement of the construction of PW2, Carty, and Tucannon River Wind Farm (Tucannon River) in 2013.

Other income, net increased $10 million, or 100%, in 2013 compared with 2012, primarily due to a $7 million increase in the allowance for equity funds used for construction from the higher average CWIP balance, as well as an increase in earnings from the non-qualified benefit plan trust assets.

Income tax expense decreased $43 million, or 67%, in 2013, compared to 2012, with the effective tax rate decreasing to 16.8% for 2013 from 31.4% for 2012. These decreases are primarily due to a decrease in the pre-tax income for 2013 compared with 2012, which was driven by the $52 million charge to expense in 2013 related to Cascade Crossing, combined with other unfavorable impacts to 2013 pre-tax income. Also contributing to the decreases was an increase to deferred tax balances in 2012 for a change in the Company's composite state tax rate and an increase in production tax credits in 2013.

2012 Compared to 2011

Revenues decreased $8 million in 2012 compared to 2011 as a result of the net effect of the items discussed below.

Total retail revenues were comparable with the prior year primarily due to the net effect of the following items:

- An $18 million increase as a result of credits provided to customers in 2011 (offset in Depreciation and amortization), with no comparable refund in 2012. The customer credits were the result of tax credits the Company had accumulated over several years in relation to the ISFSI located at the former Trojan site;
- A $14 million increase related to the PCAM, as an estimated refund to customers in the amount of $10 million was recorded in 2011 compared with a $4 million reduction in the estimated PCAM refund for the 2011 year recorded in 2012. No estimated refund or collection was recorded under the PCAM related to the 2012 year. For further discussion of the PCAM, see "Purchased power and fuel expense," below; and
- A $17 million increase resulting from supplemental tariffs and several small regulatory items, which are primarily offset in other line items in the statements of income and thus have no effect on income. The largest contributors amounted to $5 million for the recovery of costs under the solar Feed-In Tariff and $3 million for the recovery of expenses related to the Trojan refund; offset by
- A $34 million decrease related to the volume of retail energy sold and delivered. Residential volumes were down 3%, primarily driven by warmer temperatures during the heating season in 2012. Deliveries to industrial customers were up 2% due largely to increased demand from the high technology sector; and
- A $15 million decrease related to changes in the average retail price, resulting primarily from tariff changes effective January 1, 2012 as authorized by the OPUC including lower anticipated power costs included in the AUT partially offset by a $7 million net annual increase related to the tariff for recovery of Boardman

over a shortened operating life. Incremental revenues under the Boardman tariff for the full year 2012 were $14 million compared with $7 million for the last six months of 2011.

Heating degree-days in 2012 were 2% less than the 15-year average provided by the National Weather Service, as measured at Portland International Airport, and decreased 10% compared with 2011, which had 10% more heating degree-days that the 15-year average. The following table indicates the number of heating and cooling degree-days for the periods presented, along with 15-year averages:

	Heating Degree-Days			Cooling Degree-Days		
	2012	2011	Increase/ (decrease)	2012	2011	Increase/ (decrease)
1st quarter	1,967	1,974	— %	—	—	—%
2nd quarter	709	946	(25)	40	16	150
3rd quarter	58	51	14	395	346	14
4th quarter	1,435	1,679	(15)	1	—	—
	4,169	4,650	(10)	436	362	20
15-year annual average	4,235	4,219	—	456	464	(2)
Increase (decrease) from the 15-year annual average	(2)%	10%		(4)%	(22)%	

On a weather adjusted basis, retail energy deliveries in 2012 increased 0.6% compared to 2011, with deliveries to residential, commercial, and industrial customers increasing by 0.4%, 0.2%, and 1.7%, respectively.

Wholesale revenues in 2012 decreased $11 million, or 18%, from 2011 and consisted of $14 million related to a 22% decline in the average wholesale price, driven by lower electricity market prices due to the relatively low price of natural gas and a surplus of hydro generation in the region, partially offset by $3 million related to a 5% increase in wholesale energy sales volume.

Purchased power and fuel expense decreased $34 million, or 4%, in 2012 from 2011, with $19 million related to a 3% decrease in average variable power cost per MWh, partially offset by $11 million related to a 1% decrease in total system load. The decrease in the average variable power cost to $34.25 per MWh in 2012 from $35.15 per MWh in 2011 was largely due to lower wholesale power prices resulting from favorable hydro conditions and low natural gas prices.

Hydroelectric energy, from PGE-owned hydroelectric projects and from mid-Columbia projects combined, decreased 24% during 2012 from 2011, which was primarily the result of the expiration of a contract related to a mid-Columbia project that represented approximately 156 MW of capacity. Favorable hydro conditions in both years resulted in total hydroelectric energy received for each respective year exceeding that projected in the Company's AUT by approximately 11% for 2012 and 13% for 2011.

The following table presents the actual of the April-to-September runoff for 2012 and 2011 (as a percentage of normal, as measured over the 30-year period from 1971 through 2000):

	Runoff as a Percent of Normal *	
Location	2012 Actual	2011 Actual
Columbia River at The Dalles, Oregon	126%	135%
Mid-Columbia River at Grand Coulee, Washington	129	123
Clackamas River at Estacada, Oregon	133	135
Deschutes River at Moody, Oregon	118	120

* Volumetric water supply forecasts for the Pacific Northwest region are prepared by the Northwest River Forecast Center in conjunction with the Natural Resources Conservation Service and other cooperating agencies.

Energy received from PGE-owned wind generating resources (Biglow Canyon) decreased 7% from 2011, and represented 6% of the Company's retail load requirement in 2012 and in 2011. The decrease from prior year was due to unfavorable wind conditions, with energy received from Biglow Canyon falling short of projections included in the Company's AUT by approximately 20% in 2012 compared with 13% in 2011.

Actual NVPC decreased approximately $23 million for 2012 compared with 2011, largely due to a 3% decrease in average variable power cost per MWh combined with a 1% decrease in total system load. For 2012, actual NVPC was $17 million below baseline NVPC, compared with $34 million below baseline NVPC for 2011.

Production and distribution expense increased $10 million, or 5%, in 2012 compared to 2011, primarily due to the following:

- A $4 million increase due to higher maintenance costs of the Company's generating plants and distribution system;
- A $3 million increase due to an insurance recovery related to the Selective Water Withdrawal project recorded in 2011; and
- A $3 million increase due to higher delivery system labor costs.

Administrative and other expense increased $2 million, or 1%, in 2012 compared to 2011, primarily due to the following:

- A $6 million decrease due to expenses related to information technology upgrades in 2011;
- A $3 million decrease related to higher write-offs of uncollectible customer accounts in 2011;
- A $2 million decrease in compensation expense primarily due to lower incentive compensation in 2012; partially offset by
- A $7 million increase in employee pension expenses resulting from a lower discount rate and lower return on pension trust assets; and
- A $3 million increase due to the amortization of deferred expenses related to the Trojan refund (offset in Revenues).

Depreciation and amortization expense decreased $21 million, or 9%, in 2012 compared to 2011, due largely to the net effect of the following:

- An $18 million increase related to the amortization of customer refunds for the ISFSI tax credits in 2011 (offset in Revenues);
- A $13 million increase in depreciation expense related to a shorter operating life for Boardman (effective July 2011 and offset in Revenues), and other capital additions including emissions control retrofits at Boardman;
- A $5 million increase in amortization related to the Solar Feed-In Tariff (offset in Revenues); partially offset by
- A $15 million decrease related to the 2012 deferral of costs related to four capital projects as approved in the 2011 General Rate Case.

Taxes other than income taxes increased $4 million, or 4%, in 2012 compared to 2011, primarily due to higher property taxes resulting from increased property values and tax rates. Also contributing to the increase were higher franchise fees.

Interest expense decreased $2 million, or 2%, in 2012 compared to 2011, primarily due to lower interest resulting from a lower average outstanding balance of long-term debt.

Other income, net was $10 million in 2012 compared to $6 million in 2011. The increase is primarily due to higher income from the non-qualified benefit plan trust.

Income tax expense increased $6 million, or 10%, in 2012 compared to 2011, with effective tax rates of 31.4% and 28.3% for 2012 and 2011, respectively. The increase in the effective tax rate is primarily due to the change in apportionment of state income taxes, which resulted in an increase to deferred taxes. The change in apportionment was caused by lower wholesale sales in Washington, which has no corporate income tax, resulting in more taxable income being apportioned to Oregon.

Liquidity and Capital Resources

Discussions, forward-looking statements and projections in this section, and similar statements in other parts of the Form 10-K, are subject to PGE's assumptions regarding the availability and cost of capital. See "Current capital and credit market conditions could adversely affect the Company's access to capital, cost of capital, and ability to execute its strategic plan as currently scheduled." in Item 1A.—"Risk Factors."

Capital Requirements

The following table indicates actual capital expenditures for 2013 and future debt maturities and projected cash requirements for 2014 through 2018 (in millions, excluding allowance for funds used during construction, or AFDC):

	Years Ending December 31,					
	2013	2014	2015	2016	2017	2018
Ongoing capital expenditures	$ 315	$ 325	$ 290	$ 290	$ 250	$ 240
Port Westward Unit 2	155	130	15	—	—	—
Carty Generating Station	135	155	115	45	—	—
Tucannon River Wind Farm	95	390	15	—	—	—
Hydro licensing and construction	20	40	35	5	5	5
Total capital expenditures	$ 720 (1)	$ 1,040	$ 470	$ 340	$ 255	$ 245
Long-term debt maturities	$ 100	$ —	$ 70	$ 67	$ 58	$ 75

(1) Amounts shown include removal costs, which are included in other net operating activities in the consolidated statements of cash flows.

For a discussion concerning PGE's ability to fund its future capital requirements, see "Debt and Equity Financings" in this Item 7.

Ongoing capital expenditures—Consists of upgrades to and replacement of transmission, distribution, and generation infrastructure as well as new customer connections.

Port Westward Unit 2—In January 2013, PGE's PW2 flexible generating resource was selected as the successful bid for the capacity resource in the Company's RFP for energy and capacity resources. PW2 is a 220 MW natural gas-fired plant that will be located adjacent to Port Westward and Beaver near Clatskanie, Oregon. Total cost of PW2 is estimated at $300 million, excluding AFDC, and the facility is expected to be online in the first quarter of 2015. Construction commenced in May 2013, and as of December 31, 2013, $162 million, including AFDC, is included in CWIP for PW2.

Carty Generating Station—In June 2013, Carty, a proposed 440 MW natural gas-fired power plant in Eastern Oregon, located adjacent to Boardman, was selected as the successful bid for the energy (baseload) resource in the Company's RFP for energy and capacity resources. Total cost of Carty is estimated at $450 million, excluding

AFDC, and the facility is expected to be online in 2016. Construction commenced in January 2014, and as of December 31, 2013, $138 million, including AFDC, is included in CWIP for Carty.

Tucannon River Wind Farm—In June 2013, Tucannon River in southeastern Washington was selected as the successful bid for the renewable resource in the Company's RFP for renewable resources. Tucannon River, with a nameplate capacity of 267 MW, consisting of 116 turbines each with a generating capacity of 2.3 MWs, is expected to be in service in the first half of 2015 at an estimated cost of $500 million, excluding AFDC. Construction commenced in September 2013, and as of December 31, 2013, $99 million, including AFDC, is included in CWIP for Tucannon River.

Hydro licensing and construction—PGE's hydroelectric projects are operated pursuant to FERC licenses issued under the Federal Power Act. The licenses for the hydroelectric projects expire as follows: Clackamas River, 2055; Willamette River, 2035; and Deschutes River, 2055. Capital spending requirements reflected in the table above relate primarily to modifications to the Company's various hydro facilities to enhance fish passage and survival, as required by conditions contained in the operating licenses.

Liquidity

PGE's access to short-term debt markets, including revolving credit from banks, helps provide necessary liquidity to support the Company's operating activities, including the purchase of power and fuel. Long-term capital requirements are driven largely by capital expenditures for distribution, transmission, and generation facilities to support both new and existing customers, as well as debt refinancing activities. PGE's liquidity and capital requirements can also be significantly affected by other working capital needs, including margin deposit requirements related to wholesale market activities, which can vary depending upon the Company's forward positions and the corresponding price curves.

The following summarizes PGE's cash flows for the periods presented (in millions):

	Years Ended December 31,		
	2013	**2012**	**2011**
Cash and cash equivalents, beginning of year	$ 12	$ 6	$ 4
Net cash provided by (used in):			
Operating activities	544	494	453
Investing activities	(692)	(294)	(299)
Financing activities	243	(194)	(152)
Net change in cash and cash equivalents	95	6	2
Cash and cash equivalents, end of year	$ 107	$ 12	$ 6

2013 Compared to 2012

Cash Flows from Operating Activities—Cash flows from operating activities are generally determined by the amount and timing of cash received from customers and payments made to vendors, as well as the nature and amount of non-cash items, including depreciation and amortization, deferred income taxes, and pension and other postretirement benefit costs included in net income during a given period. The $50 million increase in cash flows from operating activities in 2013 compared to 2012 was largely due to the receipt of $44 million in the third quarter of 2013 related to the settlement of a legal matter concerning costs associated with the operation of the ISFSI. Such amount was transferred into the Nuclear decommissioning trust, and consequently is also reflected as an outflow of cash for investing activities. The net change in working capital items, partially offset by a decrease in net income after the consideration of non-cash items, also contributed to the increase in cash flows from operating activities.

Cash provided by operations includes the recovery in customer prices of non-cash charges for depreciation and amortization. The Company estimates that such charges in 2014 will range from $300 million to $310 million.

Combined with all other sources, cash provided by operations in 2014 is estimated to range from $500 million to $520 million. This estimate anticipates no change in margin deposits held by brokers as of December 31, 2013, which is based on both the timing of contract settlements and projected energy prices. The remaining estimated cash flows from operations in 2014 is expected from normal operating activities.

Cash Flows from Investing Activities—Cash flows used in investing activities consist primarily of capital expenditures related to new construction and improvements to PGE's distribution, transmission, and generation facilities. The $398 million increase in net cash used in investing activities in 2013 compared to 2012 was primarily due to a $353 million increase in capital expenditures, largely due to the construction of three new generation projects (PW2, Carty and Tucannon River), and a $44 million contribution to the Nuclear decommissioning trust in the third quarter of 2013. For additional information regarding the contribution to the Nuclear decommissioning trust, see Note 7, Asset Retirement Obligations, in the Notes to Consolidated Financial Statements in Item 8. —"Financial Statements and Supplementary Data."

The Company plans approximately $1 billion of capital expenditures in 2014 related to upgrades to and replacement of transmission, distribution and generation infrastructure, including $675 million related to the construction of three new generation resources. PGE plans to fund the 2014 capital expenditures with the cash expected to be generated from operations during 2014, as discussed above, as well as with the issuance of debt and equity securities. For additional information, see "*Capital Requirements*" and "*Debt and Equity Financings*" in the Liquidity and Capital Resources section of this Item 7.

Cash Flows from Financing Activities—Financing activities provide supplemental cash for both day-to-day operations and capital requirements as needed. During 2013, cash provided by such activities consisted of net proceeds received from the issuances of common stock in the aggregate amount of $67 million and FMBs in the aggregate amount of $377 million, partially offset by the repayment of FMBs of $100 million and commercial paper of $17 million, and payment of dividends of $84 million. During 2012, net cash used in financing activities consisted of the repayment of FMBs of $100 million, payment of dividends of $81 million and net maturities of commercial paper of $13 million.

2012 Compared to 2011

Cash Flows from Operating Activities—The $41 million increase in cash provided by operating activities in 2012 compared to 2011 was largely due to the impact of a combined contribution of $42 million to the pension plan and the voluntary employees' beneficiary association trusts (VEBAs) in 2011 and a decrease in margin deposit requirements, partially offset by a decrease in net income after the consideration of non-cash items. The VEBAs fund the benefits of the Company's non-contributory postretirement health and life insurance plans.

Cash Flows from Investing Activities—The $5 million decrease in cash used in investing activities in 2012 compared to 2011 was primarily due to proceeds received in the amount of $10 million for the sale of a solar power facility during the first quarter of 2012, partially offset by a 1% increase in capital expenditures.

Cash Flows from Financing Activities—During 2012, net cash used in financing activities consisted of the repayment of FMBs of $100 million, the payment of dividends of $81 million and net maturities of commercial paper of $13 million. During 2011, net cash used in financing activities primarily consisted of the payment of dividends of $79 million and the repayment of long-term debt of $80 million, including the premium paid, partially offset by net issuances of commercial paper of $11 million.

Dividends on Common Stock

The following table indicates common stock dividends declared in 2013:

Declaration Date	Record Date	Payment Date	Declared Per Common Share
February 20, 2013	March 25, 2013	April 15, 2013	$ 0.270
May 22, 2013	June 25, 2013	July 15, 2013	0.275
July 31, 2013	September 25, 2013	October 15, 2013	0.275
October 30, 2013	December 26, 2013	January 15, 2014	0.275

While the Company expects to pay comparable quarterly dividends on its common stock in the future, the declaration of any dividends is at the discretion of the Company's Board of Directors. The amount of any dividend declaration will depend upon factors that the Board of Directors deems relevant and may include, but are not limited to, PGE's results of operations and financial condition, future capital expenditures and investments, and applicable regulatory and contractual restrictions.

Credit Ratings and Debt Covenants

PGE's secured and unsecured debt is rated investment grade by Moody's and S&P, with current credit ratings and outlook as follows:

	Moody's	S&P
First Mortgage Bonds	A1	A-
Senior unsecured debt	A3	BBB
Commercial paper	Prime-2	A-2
Outlook	Stable	Stable

In January 2014, Moody's upgraded their credit ratings on the Company's FMBs to 'A1' from 'A2' and senior unsecured debt to 'A3' from 'Baa1,' with no changes to their rating on PGE's commercial paper or their outlook on PGE. The credit rating upgrades were primarily driven by Moody's favorable view of the relative credit support of the United States regulatory framework. The upgrades also reflect Moody's acknowledgement of a high degree of credit support offered by the OPUC through a suite of cost recovery mechanisms, including forecasted test years, revenue decoupling and the ability to recover financing costs, commensurate with the spend, of certain renewable projects, and Moody's view that these recovery features provide predictability and stability of PGE's cash flows.

Should Moody's and/or S&P reduce their credit rating on PGE's unsecured debt to below investment grade, the Company could be subject to requests by certain of its wholesale, commodity and transmission counterparties to post additional performance assurance collateral in connection with its price risk management activities. The performance assurance collateral can be in the form of cash deposits or letters of credit, depending on the terms of the underlying agreements, and are based on the contract terms and commodity prices and can vary from period to period. Cash deposits provided as collateral are classified as Margin deposits in PGE's consolidated balance sheet, while any letters of credit issued are not reflected in the Company's consolidated balance sheet.

As of December 31, 2013, PGE had posted approximately $38 million of collateral with these counterparties, consisting of $9 million in cash and $29 million in letters of credit, $7 million of which is related to master netting agreements. Based on the Company's energy portfolio, estimates of energy market prices, and the level of collateral outstanding as of December 31, 2013, the approximate amount of additional collateral that could be requested upon a single agency downgrade to below investment grade is approximately $80 million and decreases to approximately $34 million by December 31, 2014. The amount of additional collateral that could be requested upon a dual agency downgrade to below investment grade is approximately $190 million and decreases to approximately $104 million by December 31, 2014.

PGE's financing arrangements do not contain ratings triggers that would result in the acceleration of required interest and principal payments in the event of a ratings downgrade. However, the cost of borrowing under the credit facilities would increase.

The issuance of FMBs requires that PGE meet earnings coverage and security provisions set forth in the Indenture of Mortgage and Deed of Trust securing the bonds. PGE estimates that on December 31, 2013, under the most restrictive issuance test in the Indenture of Mortgage and Deed of Trust, the Company could have issued up to approximately $63 million of additional FMBs. PGE expects that this amount will increase in June 2014 when the impact of the $52 million expense related to Cascade Crossing, recorded in June 2013, will no longer be applicable to this issuance test. Accordingly, PGE does not expect this test to adversely affect PGE's ability to obtain sufficient financing to satisfy its capital requirements in 2014. Any issuances of FMBs would be subject to market conditions and amounts could be further limited by regulatory authorizations or by covenants and tests contained in other financing agreements. PGE also has the ability to release property from the lien of the Indenture of Mortgage and Deed of Trust under certain circumstances, including bond credits, deposits of cash, or certain sales, exchanges or other dispositions of property.

PGE's credit facilities contain customary covenants and credit provisions, including a requirement that limits consolidated indebtedness, as defined in the credit agreements, to 65% of total capitalization (debt to total capital ratio). As of December 31, 2013, the Company's debt to total capital ratio, as calculated under the credit agreements, was 51.3%.

Debt and Equity Financings

PGE's ability to secure sufficient long-term capital at a reasonable cost is determined by its financial performance and outlook, capital expenditure requirements, alternatives available to investors, and other factors. The Company's ability to obtain and renew such financing depends on its credit ratings, as well as on credit markets, both generally and for electric utilities in particular. Management believes that the availability of credit facilities, the expected ability to issue long-term debt and equity securities, and cash expected to be generated from operations provide sufficient liquidity to meet the Company's anticipated capital and operating requirements for the foreseeable future. However, the Company's ability to issue long-term debt and equity could be adversely affected by changes in capital market conditions. For 2014, PGE expects to fund estimated capital requirements with cash from operations and issuances of debt securities ranging from $350 million to $400 million and equity securities under the EFSA of approximately $285 million, with the actual timing and amount of such issuances dependent upon the timing and amount of capital expenditures.

Short-term Debt. PGE has approval from the FERC to issue short-term debt up to a total of $900 million through February 6, 2016 and currently has the following unsecured revolving credit facilities:

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

These revolving credit facilities supplement operating cash flows and provide a primary source of liquidity. Pursuant to the terms of the agreements, the revolving credit facilities may be used for general corporate purposes, backup for commercial paper borrowings, and the issuance of standby letters of credit.

As of December 31, 2013, PGE had no borrowings outstanding under the revolving credit facilities, no commercial paper outstanding, and $37 million of letters of credit issued. As of December 31, 2013, the aggregate unused available credit under the revolving credit facilities was $663 million.

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. Under these facilities, an additional $37 million of letters of credit was outstanding as of December 31, 2013.

Long-term Debt. During 2013, PGE repaid a total of $100 million of FMBs, in accordance with the terms of the debt agreements, and issued a total of $380 million of FMBs, consisting of the following:

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

As of December 31, 2013, total long-term debt outstanding was $1,916 million, with no scheduled maturities in 2014. In addition, of the $27 million of Pollution Control Revenue Bonds held by the Company, PGE has the option to remarket $21 million through 2033 and retired $6 million in January 2014.

Equity. On June 11, 2013, PGE entered into an EFSA in connection with the public offering of 11,100,000 shares of its common stock, with an initial value of $317 million. Pursuant to the EFSA, a forward counterparty borrowed 11,100,000 shares of PGE's common stock from third parties and such borrowed shares were sold in a registered public offering. PGE receives proceeds from the sale of the common stock when the EFSA is physically settled. Through December 31, 2013, the Company had the following equity transactions in connection with the offering:

- On June 17, 2013, the underwriters exercised their over-allotment option in full and PGE issued 1,665,000 shares of common stock for net proceeds of $47 million; and
- On August 21, 2013, the Company issued 700,000 shares of common stock for net proceeds of $20 million.

As of December 31, 2013, the Company could have physically settled the EFSA by delivering 10,400,000 shares of PGE common stock to the forward counterparty in exchange for cash of $288 million. The Company anticipates physical settlement of the EFSA by delivery of newly issued shares on or before June 11, 2015. For additional information on the EFSA, see Note 12, Equity-based Plans, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

Capital Structure. PGE's financial objectives include the balancing of debt and equity to maintain a low weighted average cost of capital while retaining sufficient flexibility to meet the Company's financial obligations. PGE attempts to maintain a common equity ratio (common equity to total consolidated capitalization, including current debt maturities) of approximately 50%. Achievement of this objective while sustaining sufficient cash flow is necessary to maintain acceptable credit ratings and allow access to long-term capital at attractive interest rates. The Company's common equity ratios were 48.7% and 51.1% as of December 31, 2013 and 2012, respectively.

Contractual Obligations and Commercial Commitments

The following indicates PGE's contractual obligations as of December 31, 2013 (in millions):

	2014	2015	2016	2017	2018	There-after	Total
Long-term debt	$ —	$ 70	$ 67	$ 58	$ 75	$1,646	$1,916
Interest on long-term debt (1)	107	105	100	99	94	1,392	1,897
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
Pension plan contributions (2)	—	—	23	21	11	—	55
Operating leases	11	9	10	10	10	191	241
Total	$1,184	$ 514	$ 437	$ 338	$ 337	$4,024	$6,834

(1) Future interest on long-term debt is calculated based on the assumption that all debt remains outstanding until maturity. For debt instruments with variable rates, interest is calculated for all future periods using the rates in effect as of December 31, 2013.

(2) Contributions to the Company's pension plan are not estimated beyond 2018 due to significant uncertainty in financial market and demographic outcomes.

Other Financial Obligations

PGE has entered into long-term power purchase contracts with certain public utility districts in the state of Washington under which it has acquired a percentage of the output (Allocation) of three hydroelectric projects (the Priest Rapids, Wanapum and Wells hydroelectric projects). The Company is required to pay its proportionate share of the operating and debt service costs of the projects whether or not they are operable. The contracts further 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 both the output and the operating and debt service costs of the defaulting purchaser. For the Wells project, PGE would be allocated up to a cumulative maximum of 25% of the defaulting purchaser's percentage Allocation. For the Priest Rapids and Wanapum projects, PGE would be allocated up to a cumulative maximum that would not adversely affect the tax exempt status of any outstanding debt.

Off-Balance Sheet Arrangements

In June 2013, PGE entered into an EFSA in connection with a registered public offering of its common stock. The Company may settle the EFSA with issuance of PGE common stock, for cash or net share settlement from time-to-time, in whole or part, through June 11, 2015. For additional information on the EFSA, see Note 12, Equity-based Plans, in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

PGE has no other off-balance sheet arrangements other than outstanding letters of credit from time to time that have, or are reasonably likely to have, a material current or future effect on its consolidated financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Critical Accounting Policies

The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the United States of America requires that management apply accounting policies and make estimates and assumptions that affect amounts reported in the statements. The following accounting policies represent those that management believes are particularly important to the consolidated financial statements and that require the use of estimates, assumptions, and judgments to determine matters that are inherently uncertain.

Regulatory Accounting

As a rate-regulated enterprise, PGE is required to comply with certain regulatory accounting requirements, which include the recognition of regulatory assets and liabilities on the Company's consolidated balance sheets. Regulatory assets represent probable future revenue associated with certain incurred costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited or refunded to customers through the ratemaking process. Regulatory accounting is appropriate as long as prices are established 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. Amortization of regulatory assets and liabilities is reflected in the statement of income over the period in which they are included in customer prices.

If future recovery of regulatory assets ceases to be probable, PGE would be required to write them off. Further, if PGE determines that all or a portion of its utility operations no longer meet the criteria for continued application of regulatory accounting, the Company would be required to write off those regulatory assets and liabilities related to operations that no longer meet requirements for regulatory accounting. Discontinued application of regulatory accounting would have a material impact on the Company's results of operations and financial position.

Asset Retirement Obligations

PGE recognizes AROs for legal obligations related to dismantlement and restoration costs associated with the future retirement of tangible long-lived assets. Upon initial recognition of AROs that are measurable, the probability-weighted future cash flows for the associated retirement costs, discounted using a credit-adjusted risk-free rate, are recognized as both a liability and as an increase in the capitalized carrying amount of the related long-lived assets. Due to the long lead time involved, a market-risk premium cannot be determined for inclusion in future cash flows. In estimating the liability, management must utilize significant judgment and assumptions in determining whether a legal obligation exists to remove assets. Other estimates may be related to lease provisions, ownership agreements, licensing issues, cost estimates, inflation, and certain legal requirements. Changes that may arise over time with regard to these assumptions and determinations can change future amounts recorded for AROs.

Capitalized asset retirement costs related to electric utility plant are depreciated over the estimated life of the related asset and included in Depreciation and amortization expense in the consolidated statements of income. Accretion of the ARO liability is classified as an operating expense in the consolidated statements of income. Accumulated asset retirement removal costs that do not qualify as AROs have been reclassified from accumulated depreciation to regulatory liabilities in the consolidated balance sheets.

Revenue Recognition

Retail customers are billed monthly for electricity use based on meter readings taken throughout the month. At the end of each month, PGE estimates the revenue earned from the last meter read date through the last day of the month, which has not yet been billed to customers. Such amount, which is classified as Unbilled revenues in the Company's consolidated balance sheet, 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 customer prices.

Contingencies

PGE has various unresolved legal and regulatory matters about which there is inherent uncertainty, with the ultimate outcome contingent upon several factors. Such contingencies are evaluated using the best information available. A loss contingency is accrued, and disclosed if material, when it is probable that an asset has been impaired or a liability incurred and the amount of the loss can be reasonably estimated. If a range of probable loss is established, the minimum amount in the range is accrued, unless some other amount within the range appears to be a better estimate. If the probable loss cannot be reasonably estimated, no accrual is recorded, but the loss contingency is disclosed to the effect that it cannot be reasonably estimated. Material loss contingencies are disclosed when it is reasonably possible that an asset has been impaired or a liability incurred. Established accruals reflect management's assessment of inherent risks, credit worthiness, and complexities involved in the process. There can be no assurance as to the ultimate outcome of any particular contingency.

Price Risk Management

PGE engages in price risk management activities to manage exposure to commodity and foreign currency market fluctuations and to manage volatility in net power costs for its retail customers. The Company utilizes derivative instruments, which may include forward, futures, swap, and option contracts for electricity, natural gas, oil, and foreign currency. These derivative instruments are recorded at fair value, or "marked-to-market," in PGE's consolidated financial statements.

Fair value adjustments consist of reevaluating the fair value of derivative contracts at the end of each reporting period for the remaining term of the contract and recording any change in fair value in Net income for the period. Fair value is the present value of the difference between the contracted price and the forward market price multiplied by the total quantity of the contract. For option contracts, a theoretical value is calculated using Black-Scholes models that utilize price volatility, price correlation, time to expiration, interest rate and forward commodity price curves. The fair value of these options is the difference between the premium paid or received and the theoretical value at the fair value measurement date.

Determining the fair value of these financial instruments requires the use of prices at which a buyer or seller could currently contract to purchase or sell a commodity at a future date (termed "forward prices"). Forward price "curves" are used to determine the current fair market value of a commodity to be delivered in the future. PGE's forward price curves are created by utilizing actively quoted market indicators received from electronic and telephone brokers, industry publications, and other sources. Forward price curves can change with market conditions and can be materially affected by unpredictable factors such as weather and the economy. PGE's forward price curves are validated using broker quotes and market data from a regulated exchange and differences for any single location, delivery date and commodity are less than 5%.

Pension Plan

Primary assumptions used in the actuarial valuation of PGE's pension plan include the discount rate, the expected return on plan assets, mortality rates, and wage escalation. These assumptions are evaluated by the Company, reviewed annually with the plan actuaries and trust investment consultants, and updated in light of market changes, trends, and future expectations. Significant differences between assumptions and actual experience can have a material impact on the valuation of the pension benefit plan obligation and net periodic pension cost.

PGE's pension discount rate is determined based on a portfolio of high-quality bonds that match the duration of the plan cash flows. The expected rate of return on plan assets is based on the projected long-term return on assets in the plan investment portfolio. PGE capitalizes a portion of pension expense based on the proportion of labor costs capitalized.

Changes in actuarial assumptions can also have a material effect on net periodic pension expense. A 0.25% reduction in the expected long-term rate of return on plan assets, or reduction in the discount rate, would have the effect of increasing the 2013 net periodic pension expense by approximately $2 million.

Fair Value Measurements

PGE applies fair value measurements to its financial assets and liabilities, with fair value defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The Company's financial assets and liabilities consist of derivative instruments entered into in connection with its price risk management activities, certain assets held by the Nuclear decommissioning, Pension plan and Non-qualified benefit plan trusts, and long-term debt. In valuing these items, the Company uses inputs and assumptions that market participants would use to determine their fair value, utilizing valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The determination of fair value can require subjective and complex judgment and PGE's assessment of the inputs and the significance of a particular input to fair value measurement may affect the valuation of the instruments and their placement within the fair value hierarchy reported in its financial statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

PGE is exposed to various forms of market risk, consisting primarily of fluctuations in commodity prices, foreign currency exchange rates, and interest rates, as well as credit risk. Any variations in the Company's market risk or credit risk may affect its future financial position, results of operations or cash flows, as discussed below.

Risk Management Committee

PGE has a Risk Management Committee (RMC) which is responsible for providing oversight of the adequacy and effectiveness of corporate policies, guidelines, and procedures for market and credit risk management related to the Company's energy portfolio management activities. The RMC consists of officers and Company representatives with responsibility for risk management, finance and accounting, legal, rates and regulatory affairs, power operations, and generation operations. The RMC reviews and approves adoption of policies and procedures, and monitors compliance with policies, procedures, and limits on a regular basis through reports and meetings. The RMC also reviews and recommends risk limits that are subject to approval by PGE's Board of Directors.

Commodity Price Risk

PGE is exposed to commodity price risk as its primary business is to provide electricity to its retail customers. The Company engages in price risk management activities to manage exposure to volatility in net power costs for its retail customers. The Company uses power purchase contracts to supplement its thermal, hydroelectric, and wind generation and to respond to fluctuations in the demand for electricity and variability in generating plant operations. The Company also enters into contracts for the purchase of fuel for the Company's natural gas- and coal-fired generating plants. These contracts for the purchase of power and fuel expose the Company to market risk. The Company uses instruments such as forward contracts, which may involve physical delivery of an energy commodity; financial swap and futures agreements, which may require payments to, or receipt of payments from, counterparties based on the differential between a fixed and variable price for the commodity; and option contracts to mitigate risk that arises from market fluctuations of commodity prices. PGE does not engage in trading activities for non-retail purposes.

The following table presents energy commodity derivative fair values as a net liability as of December 31, 2013 that are expected to settle in each respective year (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
	$ 36	$ 36	$ 26	$ 15	$ 5	$ 58	$ 176

PGE reports energy commodity derivative fair values as a net asset or liability, which combines purchases and sales expected to settle in the years noted above. As a short utility, energy commodity fair values exposed to commodity price risk are primarily related to purchase contracts, which are slightly offset by sales.

PGE's energy portfolio activities are subject to regulation, with related costs included in retail prices approved by the OPUC. The timing differences between the recognition of gains and losses on certain derivative instruments and their realization and subsequent recovery in prices are deferred as regulatory assets and regulatory liabilities to reflect the effects of regulation, significantly mitigating commodity price risk for the Company. As contracts are settled, these deferrals reverse and are recognized as Purchased power and fuel in the statements of income and included in the PCAM. PGE remains subject to cash flow risk in the form of collateral requirements based on the value of open positions and regulatory risk if recovery is disallowed by the OPUC. PGE attempts to mitigate both types of risks through prudent energy procurement practices.

Foreign Currency Exchange Rate Risk

PGE is exposed to foreign currency risk associated with natural gas forward and swap contracts denominated in Canadian dollars in its energy portfolio. Foreign currency risk is the risk of changes in value of pending financial obligations in foreign currencies that could occur prior to the settlement of the obligation due to a change in the value of that foreign currency in relation to the U.S. dollar. PGE monitors its exposure to fluctuations in the Canadian exchange rate with an appropriate hedging strategy.

As of December 31, 2013, a 10% change in the value of the Canadian dollar would result in an immaterial change in exposure for transactions that will settle over the next twelve months.

Interest Rate Risk

To meet short-term cash requirements, PGE has established a program under which it may from time to time issue commercial paper for terms of up to 270 days; such issuances are supported by the Company's unsecured revolving credit facilities. Although any borrowings under the commercial paper program subject the Company to fluctuations in interest rates, reflecting current market conditions, individual instruments carry a fixed rate during their respective terms. As of December 31, 2013, PGE had no borrowings outstanding under its revolving credit facilities and no commercial paper outstanding.

PGE currently has no financial instruments to mitigate risk related to changes in short-term interest rates, including those on commercial paper; however, it may consider such instruments in the future as considered necessary.

As of December 31, 2013, the total fair value and carrying amounts by maturity date of PGE's long-term debt are as follows (in millions):

	Total Fair Value	Carrying Amounts by Maturity Date					
		Total	2015	2016	2017	2018	There-after
First Mortgage Bonds	$ 1,948	$ 1,795	$ 70	$ 67	$ 58	$ 75	$ 1,525
Pollution Control Revenue Bonds	126	121	—	—	—	—	121
Total	$ 2,074	$ 1,916	$ 70	$ 67	$ 58	$ 75	$ 1,646

As of December 31, 2013, PGE had no long-term variable rate debt outstanding; accordingly, the Company's outstanding long-term debt is not subject to interest rate risk exposures.

Credit Risk

PGE is exposed to credit risk in its commodity price risk management activities related to potential nonperformance by counterparties. PGE manages the risk of counterparty default according to its credit policies by performing financial credit reviews, setting limits and monitoring exposures, and requiring collateral (in the form of cash, letters of credit, and guarantees) when needed. The Company also uses standardized enabling agreements and, in certain cases, master netting agreements, which allow for the netting of positive and negative exposures under multiple agreements with counterparties. Despite such mitigation efforts, defaults by counterparties may periodically occur. Based upon periodic review and evaluation, allowances are recorded to reflect credit risk related to wholesale accounts receivable.

The large number and diversified base of residential, commercial, and industrial customers, combined with the Company's ability to discontinue service, contribute to reduce credit risk with respect to trade accounts receivable from retail sales. Estimated provisions for uncollectible accounts receivable related to retail sales are provided for such risk.

As of December 31, 2013, PGE's credit risk exposure is $6 million for commodity activities with externally-rated investment grade counterparties and matures in 2014. The credit risk is included in accounts receivable and price risk management assets, offset by related accounts payable and price risk management liabilities.

Investment grade includes those counterparties with a minimum credit rating on senior unsecured debt of Baa3 (as assigned by Moody's) or BBB- (as assigned by S&P), and also those counterparties whose obligations are guaranteed or secured by an investment grade entity. The credit exposure includes activity for electricity and natural gas forward, swap, and option contracts. Posted collateral may be in the form of cash or letters of credit and may represent prepayment or credit exposure assurance.

Omitted from the market risk exposures discussed above are long-term power purchase contracts with certain public utility districts in the state of Washington and with the City of Portland, Oregon. These contracts provide PGE with a percentage share of hydro facility output in exchange for an equivalent percentage share of operating and debt service costs. These contracts expire at varying dates through 2052. For additional information, see "*Public Utility Districts*" in Note 15, Commitments and Guarantees, in the Notes to Consolidated Financial Statements in Item 8. —"Financial Statements and Supplementary Data." Management believes that circumstances that could result in the nonperformance by these counterparties are remote.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

The following financial statements and report are included in Item 8:

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of
Portland General Electric Company
Portland, Oregon

We have audited the accompanying consolidated balance sheets of Portland General Electric Company and subsidiaries (the "Company") as of December 31, 2013 and 2012, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2013. We also have audited the Company's internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control-Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Portland General Electric Company and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the criteria established in *Internal Control-Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 13, 2014

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(Dollars in millions, except per share amounts)

	Years Ended December 31,		
	2013	**2012**	**2011**
Revenues, net	$ 1,810	$ 1,805	$ 1,813
Operating expenses:			
Purchased power and fuel	757	726	760
Production and distribution	225	211	201
Cascade Crossing transmission project	52	—	—
Administrative and other	219	216	218
Depreciation and amortization	248	248	227
Taxes other than income taxes	103	102	98
Total operating expenses	1,604	1,503	1,504
Income from operations	206	302	309
Interest expense, net	101	108	110
Other income:			
Allowance for equity funds used during construction	13	6	5
Miscellaneous income, net	7	4	1
Other income, net	20	10	6
Income before income taxes	125	204	205
Income tax expense	21	64	58
Net income	104	140	147
Less: net loss attributable to noncontrolling interests	(1)	(1)	—
Net income attributable to Portland General Electric Company	$ 105	$ 141	$ 147
Weighted-average shares outstanding (in thousands):			
Basic	76,821	75,498	75,333
Diluted	77,388	75,647	75,350
Earnings per share:			
Basic	$ 1.36	$ 1.87	$ 1.95
Diluted	$ 1.35	$ 1.87	$ 1.95

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(In millions)

	Years Ended December 31,		
	2013	2012	2011
Net income	$ 104	$ 140	$ 147
Other comprehensive income (loss)—Change in compensation retirement benefits liability and amortization, net of taxes of ($1) in 2013 and $1 in 2011	1	—	(1)
Comprehensive income	105	140	146
Less: comprehensive loss attributable to the noncontrolling interests	(1)	(1)	—
Comprehensive income attributable to Portland General Electric Company	$ 106	$ 141	$ 146

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In millions)

	As of December 31,	
	2013	**2012**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 107	$ 12
Accounts receivable, net	146	152
Unbilled revenues	104	97
Inventories, at average cost:		
Materials and supplies	41	38
Fuel	24	40
Margin deposits	9	46
Regulatory assets—current	66	144
Other current assets	94	93
Total current assets	591	622
Electric utility plant:		
Production	2,968	2,899
Transmission	417	412
Distribution	2,943	2,816
General	381	327
Intangible	386	357
Construction work-in-progress	508	140
Total electric utility plant	7,603	6,951
Accumulated depreciation and amortization	(2,723)	(2,559)
Electric utility plant, net	4,880	4,392
Regulatory assets—noncurrent	464	524
Nuclear decommissioning trust	82	38
Non-qualified benefit plan trust	35	32
Other noncurrent assets	49	62
Total assets	$ 6,101	$ 5,670

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS, continued
(In millions, except share amounts)

	As of December 31, 2013	As of December 31, 2012
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 173	$ 98
Liabilities from price risk management activities—current	49	127
Short-term debt	—	17
Current portion of long-term debt	—	100
Accrued expenses and other current liabilities	171	179
Total current liabilities	393	521
Long-term debt, net of current portion	1,916	1,536
Regulatory liabilities—noncurrent	865	765
Deferred income taxes	586	588
Unfunded status of pension and postretirement plans	154	247
Liabilities from price risk management activities—noncurrent	141	73
Non-qualified benefit plan liabilities	101	102
Asset retirement obligations	100	94
Other noncurrent liabilities	25	14
Total liabilities	4,281	3,940
Commitments and contingencies (see notes)		
Equity:		
Portland General Electric Company shareholders' equity:		
Preferred stock, no par value, 30,000,000 shares authorized; none issued and outstanding	—	—
Common stock, no par value, 160,000,000 shares authorized; 78,085,559 and 75,556,272 shares issued and outstanding as of December 31, 2013 and 2012, respectively	911	841
Accumulated other comprehensive loss	(5)	(6)
Retained earnings	913	893
Total Portland General Electric Company shareholders' equity	1,819	1,728
Noncontrolling interests' equity	1	2
Total equity	1,820	1,730
Total liabilities and equity	$ 6,101	$ 5,670

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF EQUITY
(In millions, except share amounts)

	Portland General Electric Company Shareholders' Equity				
	Common Stock		Accumulated Other Comprehensive Loss	Retained Earnings	Noncontrolling Interests' Equity
	Shares	Amount			
Balance as of December 31, 2010	75,316,419	$ 831	$ (5)	$ 766	$ 7
Shares issued pursuant to equity-based plans	46,537	1	—	—	—
Noncontrolling interests' capital distributions	—	—	—	—	(4)
Stock-based compensation	—	4	—	—	—
Dividends declared ($1.055 per share)	—	—	—	(80)	—
Net income	—	—	—	147	—
Other comprehensive loss	—	—	(1)	—	—
Balance as of December 31, 2011	75,362,956	836	(6)	833	3
Shares issued pursuant to equity-based plans	193,316	1	—	—	—
Stock-based compensation	—	4	—	—	—
Dividends declared ($1.075 per share)	—	—	—	(81)	—
Net income (loss)	—	—	—	141	(1)
Balance as of December 31, 2012	75,556,272	841	(6)	893	2
Issuances of common stock, net of issuance costs of $3	2,365,000	67	—	—	—
Shares issued pursuant to equity-based plans	164,287	1	—	—	—
Stock-based compensation	—	2	—	—	—
Dividends declared ($1.095 per share)	—	—	—	(85)	—
Net income (loss)	—	—	—	105	(1)
Other comprehensive income	—	—	1	—	—
Balance as of December 31, 2013	78,085,559	$ 911	$ (5)	$ 913	$ 1

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Years Ended December 31,		
	2013	**2012**	**2011**
Cash flows from operating activities:			
Net income	$ 104	$ 140	$ 147
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	248	248	227
(Decrease) increase in net liabilities from price risk management activities	(18)	(175)	9
Regulatory deferrals—price risk management activities	18	172	(6)
Cascade Crossing transmission project	52	—	—
Deferred income taxes	11	47	56
Renewable adjustment clause deferrals	—	1	22
Pension and other postretirement benefits	37	27	15
Regulatory deferral of settled derivative instruments	7	(9)	12
Power cost deferrals, net of amortization	(6)	(4)	10
Allowance for equity funds used during construction	(13)	(6)	(5)
Decoupling mechanism deferrals, net of amortization	(6)	2	3
Unrealized losses on non-qualified benefit plan trust assets	3	3	—
Other non-cash income and expenses, net	18	16	16
Changes in working capital:			
Increase in receivables and unbilled revenues	—	(4)	(15)
Decrease in margin deposits	37	34	3
Income tax refund received	—	8	9
Increase in payables and accrued liabilities	14	1	5
Other working capital items, net	17	1	(7)
Proceeds received from Trojan spent fuel legal settlement	44	—	—
Contribution to non-qualified employee benefit trust	(6)	—	—
Contribution to voluntary employees' benefit association trust	(3)	(2)	(16)
Contribution to pension plan	—	—	(26)
Other, net	(14)	(6)	(6)
Net cash provided by operating activities	544	494	453
Cash flows from investing activities:			
Capital expenditures	(656)	(303)	(300)
Purchases of nuclear decommissioning trust securities	(26)	(26)	(50)
Sales of nuclear decommissioning trust securities	25	23	46
Contribution to nuclear decommissioning trust	(44)	—	—
Proceeds received from insurance recovery	6	—	—
Proceeds from sale of solar power facility	—	10	—
Other, net	3	2	5
Net cash used in investing activities	(692)	(294)	(299)

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS, continued
(In millions)

	Years Ended December 31,		
	2013	2012	2011
Cash flows from financing activities:			
Proceeds from issuance of long-term debt	$ 380	$ —	$ —
Payments on long-term debt	(100)	(100)	(73)
Proceeds from issuances of common stock, net of issuance costs	67	—	—
Borrowings on short-term debt	35	—	—
Payments on short-term debt	(35)	—	—
(Maturities) issuances of commercial paper, net	(17)	(13)	11
Dividends paid	(84)	(81)	(79)
Premium paid on repayment of long-term debt	—	—	(7)
Debt issuance costs	(3)	—	—
Noncontrolling interests' capital distributions	—	—	(4)
Net cash provided by (used in) financing activities	243	(194)	(152)
Increase in cash and cash equivalents	95	6	2
Cash and cash equivalents, beginning of year	12	6	4
Cash and cash equivalents, end of year	$ 107	$ 12	$ 6
Supplemental disclosures of cash flow information:			
Cash paid for interest, net of amounts capitalized	$ 90	$ 97	$ 103
Cash paid for income taxes	10	13	3
Non-cash investing and financing activities:			
Accrued capital additions	84	19	19
Accrued dividends payable	22	21	21
Preliminary engineering transferred to Construction work in progress from Other noncurrent assets	9	—	7

See accompanying notes to consolidated financial statements.

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.

Consolidation Principles

The consolidated financial statements include the accounts of PGE and its wholly-owned subsidiaries and those variable interest entities (VIEs) where PGE has determined it is the primary beneficiary. The Company's ownership share of direct expenses and costs related to jointly-owned generating plants are also included in its consolidated financial statements. Intercompany balances and transactions have been eliminated.

For entities that are determined to meet the definition of a VIE and where the Company has determined it is the primary beneficiary, the VIE is consolidated and a noncontrolling interest is recognized for any third party interests. This has resulted in the Company consolidating entities in which it has less than a 50% equity interest. For further information, see Note 16, Variable Interest Entities.

Use of Estimates

The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America (GAAP) 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 Revenues, net, 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 cash equivalents, 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 Administrative and other expense and are recorded in the same period as the related revenues, with an offsetting credit to the allowance 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 fuel expense 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, 2012 and 2011.

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 consolidated balance sheets as assets or liabilities from price risk management activities. Changes in fair value are recognized in the consolidated 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 Revenues and Purchased power and fuel expense upon settlement, respectively, while transactions that are not physically settled (financial transactions) are recorded on a net basis in Purchased power and fuel expense upon settlement.

Pursuant to transactions entered into in connection with PGE's price risk management activities, the Company may be required to provide collateral with certain counterparties. The collateral requirements are based on the contract terms and commodity prices and can vary period to period. Cash deposits provided as collateral are classified as Margin deposits in the consolidated 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 consolidated balance sheet 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 consolidated 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 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 consolidated statements of income. The average rate used by PGE was 7.5% in 2013 and in 2012 and 7.8% in 2011. AFDC from borrowed funds was $7 million in 2013, $4 million in 2012, and $3 million in 2011 and is reflected as a reduction to Interest expense. AFDC from equity funds was $13 million in 2013, $6 million in 2012, and $5 million in 2011 and is included in Other income, net.

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, 3.8% in 2012, and 3.7% in 2011. Estimated asset retirement removal costs included in depreciation expense were $55 million in 2013 and 2012, and $49 million in 2011.

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 asset retirement removal costs, included in Regulatory liabilities, for assets without AROs.

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, and $19 million in 2011. 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 consolidated 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 consolidated 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 consolidated statements of income; and is net of (ii) wholesale sales, which are classified as Revenues, net in the consolidated 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, 2012 and 2011.

Any estimated refund to customers pursuant to the PCAM is recorded as a reduction in Revenues in the Company's consolidated statements of income, while any estimated collection from customers is recorded as a reduction in Purchased power and fuel expense. 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.

For 2011, actual NVPC was below baseline NVPC by $34 million, and exceeded the lower deadband threshold of $15 million. PGE recorded an estimated refund to customers of $10 million as of December 31, 2011, reduced from the $17 million potential refund to customers as a result of the regulated earnings test. A final determination regarding the 2011 PCAM results was made by the OPUC through a public filing and review in 2012, which, based upon the application of an updated regulated earnings test, resulted in a revised refund to customers of $6 million to be returned to customers over a one-year period beginning January 1, 2013.

Asset Retirement Obligations

Legal obligations related to the future retirement of tangible long-lived assets are classified as AROs on PGE's consolidated 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 Electric utility plant, net on the consolidated 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 consolidated 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 consolidated 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 consolidated 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 consolidated 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 consolidated 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 consolidated statements of income. Amounts collected from customers are included in Revenues, net and amounts due to taxing authorities are included in Taxes other than income taxes and totaled $41 million in 2013, $42 million in 2012, and $41 million in 2011.

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 consolidated balance sheet.

PGE records any interest and penalties related to income tax deficiencies in Interest expense and Other income, net, respectively, in the consolidated 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 consolidated financial position, consolidated results of operations, or consolidated 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, Net

Accounts receivable is net of an allowance for uncollectible accounts of $6 million and $5 million as of December 31, 2013 and 2012, respectively. The following is the activity in the allowance for uncollectible accounts (in millions):

	Years Ended December 31,		
	2013	2012	2011
Balance as of beginning of year	$ 5	$ 6	$ 5
Increase in provision	6	6	11
Amounts written off, less recoveries	(5)	(7)	(10)
Balance as of end of year	$ 6	$ 5	$ 6

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.

Other Current Assets and Accrued Expenses and Other Current Liabilities

Other current assets and Accrued expenses and other current liabilities consist of the following (in millions):

	As of December 31,	
	2013	2012
Other current assets:		
Current deferred income tax asset	$ 42	$ 51
Prepaid expenses	38	37
Assets from price risk management activities	13	4
Other	1	1
	$ 94	$ 93
Accrued expenses and other current liabilities:		
Accrued employee compensation and benefits	$ 46	$ 46
Accrued interest payable	23	23
Dividends payable	22	21
Accrued taxes payable	21	21
Regulatory liabilities—current	1	12
Other	58	56
	$ 171	$ 179

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 consolidated 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 consolidated 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 consolidated 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 consolidated 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 consolidated 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 (1)	4 (1)
Noncurrent assets:		
Commodity contracts:		
Electricity	1	—
Natural gas	—	2
Total noncurrent derivative assets	1	2
Total derivative assets not designated as hedging instruments	$ 14 (2)	$ 6 (2)
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

(1) Included in Other current assets on the consolidated balance sheets.
(2) Included in Other noncurrent assets on the consolidated balance sheet.

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 consolidated 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 Condensed Consolidated 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 and fuel in the consolidated statements of income and were as follows (in millions):

	Years Ended December 31,		
	2013	2012	2011
Commodity contracts:			
Electricity	$ 78	$ 56	$ 117
Natural Gas	28	19	98
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, 2012, and 2011, $120 million, $42 million, and $192 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 Margin deposits on the Company's consolidated 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		2012	
		Current	Noncurrent	Current	Noncurrent
Regulatory assets:					
Price risk management [2]	6 years	$ 36	$ 140	$ 123	$ 71
Pension and other postretirement plans [2]	[3]	—	194	—	321
Deferred income taxes [2]	[4]	—	76	—	80
Deferred broker settlements [2]	1 year	12	1	20	1
Debt issuance costs [2]	8 years	—	17	—	22
Deferred capital projects	2 years	16	18	—	16
Other [5]	Various	2	18	1	13
Total regulatory assets		$ 66	$ 464	$ 144	$ 524
Regulatory liabilities:					
Asset retirement removal costs [7]	[4]	$ —	$ 747	$ —	$ 692
Trojan decommissioning activities	[6]	—	41	—	—
Asset retirement obligations [7]	[4]	—	39	—	39
Other	Various	1	38	12	34
Total regulatory liabilities		$ 1 [8]	$ 865	$ 12 [8]	$ 765

(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 $15 million as of December 31, 2013 and 2012, respectively.
(6) Refund period not yet determined.
(7) Included in rate base for ratemaking purposes.
(8) Included in Accrued expenses and other current liabilities on the consolidated balance sheets.

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.

Debt issuance costs represents unrecognized debt issuance costs related to debt instruments retired prior to the stipulated maturity date.

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.

Asset retirement removal costs represent the costs that do not qualify as AROs and are a component of depreciation expense allowed in customer prices. Such costs are recorded as a regulatory liability as they are collected in prices, and are reduced by actual removal costs incurred.

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.

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 Electric utility plant, net on the consolidated balance sheet. Such transaction is non-cash and is excluded from investing activities in the consolidated statement cash flows for the year ended December 31, 2011. Furthermore, in December 2013, PGE increased the ARO by $4 million related to the acquisition of an additional 15% interest in Boardman.

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

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

	Years Ended December 31,		
	2013	2012	2011
Balance as of beginning of year	$ 94	$ 87	$ 64
Liabilities incurred	4	—	1
Liabilities settled	(4)	(3)	(4)
Accretion expense	6	6	4
Revisions in estimated cash flows	—	4	22
Balance as of end of year	$ 100	$ 94	$ 87

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 consolidated 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. Removal costs are charged to accumulated asset retirement removal costs, which is included in Regulatory liabilities on PGE's consolidated balance sheets.

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 consolidated 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 consolidated 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	2011
Average daily amount of short-term debt outstanding	$ 9	$ 4	$ 2
Weighted daily average interest rate *	0.4%	0.4%	0.4%
Maximum amount outstanding during the year	$ 54	$ 44	$ 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
Less: current portion of long-term debt	—	(100)
Long-term debt, net of current portion	$ 1,916	$ 1,536

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

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, and contributed $26 million to the plan in 2011. 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 consolidated 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 *	22	79	101	25	77	102

* For the NQBP, excludes the current portion of $2 million in 2013 and 2012, which is classified in Other current liabilities in the consolidated balance sheets.

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
Classification in consolidated balance sheet:						
Noncurrent asset	$ —	$ —	$ —	$ —	$ 16	$ 15
Current liability	—	—	—	—	(2)	(2)
Noncurrent liability	(109)	(191)	(45)	(56)	(22)	(25)
Net liability	$ (109)	$ (191)	$ (45)	$ (56)	$ (8)	$ (12)
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

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2013	2012	2013	2012	2013	2012
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	2011	2013	2012	2011	2013	2012	2011
Service cost	$ 17	$ 14	$ 12	$ 2	$ 2	$ 2	$ —	$ —	$ —
Interest cost on benefit obligation	30	31	29	3	3	4	1	1	1
Expected return on plan assets	(40)	(41)	(42)	(1)	(1)	(1)	—	—	—
Amortization of prior service cost	—	—	1	1	1	1	—	—	—
Amortization of net actuarial loss	24	17	8	1	1	1	1	1	1
Net periodic benefit cost	$ 31	$ 21	$ 8	$ 6	$ 6	$ 7	$ 2	$ 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;
- 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; and
- For 2011, 8% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2012 through 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, 2012, and 2011.

NOTE 11: INCOME TAXES

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

	Years Ended December 31,		
	2013	2012	2011
Current:			
Federal	$ 10	$ 16	$ 2
State and local	—	1	—
	10	17	2
Deferred:			
Federal	4	30	43
State and local	7	17	13
	11	47	56
Income tax expense	$ 21	$ 64	$ 58

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	2011
Federal statutory tax rate	35.0%	35.0%	35.0%
Federal tax credits	(21.8)	(11.8)	(12.7)
State and local taxes, net of federal tax benefit	3.4	3.5	2.6
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	2.1
Other	(2.6)	(0.6)	1.3
Effective tax rate	16.8%	31.1%	28.3%

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

	As of December 31,	
	2013	2012
Deferred income tax assets:		
Employee benefits	$ 122	$ 162
Price risk management	71	77
Tax credits	51	55
Regulatory liabilities	16	20
Other	17	—
Total deferred income tax assets	277	314
Deferred income tax liabilities:		
Depreciation and amortization	646	623
Regulatory assets	175	224
Other	—	4
Total deferred income tax liabilities	821	851
Deferred income tax liability, net	$ (544)	$ (537)
Classification of net deferred income taxes:		
Current deferred income tax asset (1)	$ 42	$ 51
Noncurrent deferred income tax liability	(586)	(588)
	$ (544)	$ (537)

(1) Included in Other current assets in the consolidated balance sheets.

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. During the year ended December 31, 2011, the valuation allowance decreased $2 million as a result of the expiration of unused state credits.

As of December 31, 2013 and 2012, PGE had no unrecognized tax benefits. During 2011, an unrecognized tax benefit of $2 million was recognized as a result of filing for a federal tax accounting method change.

PGE and its subsidiaries file consolidated federal income tax returns. The Company also files state income tax returns in certain jurisdictions, including Oregon, California, Montana, and 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 consolidated 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 consolidated financial position, consolidated results of operations, or consolidated 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, 2010	465,428	$ 17.88
Granted	152,657	23.84
Forfeited	(106,979)	22.35
Vested	(19,702)	23.34
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, 2012, and 2011 was $4 million, $3 million and $1 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%, 109.2%, and 107.8% of awarded performance-based restricted stock units for 2013, 2012, and 2011, 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, 2012, and 2011, PGE recorded stock-based compensation expense of $4 million, which is included in Administrative and other expense in the consolidated statements of income. Such amounts differ from those reported in the consolidated 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, $1 million in 2012, and less than $1 million in 2011, which is not included in Administrative and other expenses in the consolidated 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, 2012, or 2011.

NOTE 14: EARNINGS PER SHARE

Basic earnings per share is computed based on the weighted average number of common shares outstanding during the year. Diluted earnings per share is computed using the weighted average number of common shares outstanding and the effect of dilutive potential common shares outstanding during the year using the treasury stock method. Potential common shares consist of: (i) employee stock purchase plan shares; (ii) unvested time-based and performance-based restricted stock units, along with associated dividend equivalent rights; and (iii) shares issuable pursuant to the EFSA. See Note 12, Equity-based Plans, for additional information on the EFSA and its impact on earnings per share. Unvested performance-based restricted stock units and associated dividend equivalent rights are included in dilutive potential common shares only after the performance criteria has been met.

Net income attributable to PGE common shareholders is the same for both the basic and diluted earnings per share computation. The reconciliations of the denominators of the basic and diluted earnings per share computations are as follows (in thousands):

	Years Ended December 31,		
	2013	2012	2011
Weighted average common shares outstanding—basic	76,821	75,498	75,333
Dilutive effect of potential common shares	567	149	17
Weighted average common shares outstanding—diluted	77,388	75,647	75,350

NOTE 15: 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		Contract Expiration	PGE Cost, including Debt Service		
		Output	Capacity (in MW)		2013	2012	2011
Priest Rapids and Wanapum	$ 1,001	9.0%	170	2052	$ 14	$ 14	$ 14
Wells	232	19.4	150	2018	10	10	10
Portland Hydro	7	100.0	36	2017	4	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, $10 million in 2012, and $9 million in 2011.

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, 2012, and 2011.

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 consolidated balance sheets with respect to these indemnities.

NOTE 16: VARIABLE INTEREST ENTITIES

PGE has determined that it is the primary beneficiary of three VIEs and, therefore, consolidates the VIEs within the Company's consolidated financial statements. All three arrangements were formed for the sole purpose of designing, developing, constructing, owning, maintaining, operating and financing photovoltaic solar power facilities located on real property owned by third parties, and selling the energy generated by the facilities. The Company is the Managing Member and a financial institution is the Investor Member in each of the Limited Liability Companies (LLCs), holding equity interests of less than 1% and more than 99%, respectively, in each entity. PGE has determined that its interests in these VIEs contain the obligation to absorb the variability of the entities that could potentially be significant to the VIEs, and the Company has the power to direct the activities that most significantly affect the entities' economic performance.

Determining whether PGE is the primary beneficiary of a VIE is complex, subjective and requires the use of judgments and assumptions. Significant judgments and assumptions made by PGE in determining it is the primary beneficiary of these LLCs include the following: (i) PGE has the experience to own and operate electric generating facilities and is authorized to operate the LLCs pursuant to the operating agreements, and, therefore, PGE has control over the most significant activities of the LLCs; (ii) PGE expects to own 100% of the LLCs shortly after five years have elapsed from when the facility was placed in service, at which time the facilities will have approximately 75% of their estimated useful life remaining; and (iii) based on projections prepared in accordance with the operating agreements, PGE expects to absorb a majority of any expected losses of the LLCs.

Included in PGE's consolidated balance sheets as of December 31, 2013 and 2012 are LLC net assets of $5 million and $6 million, respectively, primarily comprised of Electric utility plant, and includes Cash and cash equivalents of $1 million. These assets can only be used to settle the obligations of the consolidated VIEs and their creditors have no recourse to the general credit of PGE.

In January 2014, PGE acquired the equity interest held by the Investor Member of one of the LLCs pursuant to the terms of the operating agreement. The transaction did not have a significant impact to the Company's consolidated financial position, consolidated results of operations or consolidated cash flows.

NOTE 17: 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 consolidated 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 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.

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 18: 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 consolidated 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 with oral argument scheduled for 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.

QUARTERLY FINANCIAL DATA

(Unaudited)

	Quarter Ended			
	March 31	June 30	September 30	December 31
	(In millions, except per share amounts)			
2013				
Revenues, net	$ 473	$ 403	$ 435	$ 499
Income (loss) from operations [(1)]	87	(11)	53	77
Net income (loss) [(1)]	48	(22)	31	47
Net income (loss) attributable to Portland General Electric Company [(1)]	49	(22)	31	47
Earnings (loss) per share—basic and diluted [(1)] [(2)]	0.65	(0.29)	0.40	0.59
2012				
Revenues, net	$ 479	$ 413	$ 450	$ 463
Income from operations	88	61	82	71
Net income	49	26	37	28
Net income attributable to Portland General Electric Company	49	26	38	28
Earnings per share—basic and diluted [(2)]	0.65	0.34	0.50	0.38

(1) The quarter ended June 30 includes $52 million of costs expensed related to the Company's Cascade Crossing Transmission Project and a refund of revenues of $9 million related to the over-billing of an industrial customer since 2009.

(2) Earnings per share are calculated independently for each period presented. Accordingly, the sum of the quarterly earnings per share amounts may not equal the total for the year.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

ITEM 9A. CONTROLS AND PROCEDURES.

(a) Disclosure Controls and Procedures

Management of the Company, under the supervision and with the participation of the Chief Executive Officer and the Chief Financial Officer, has evaluated the effectiveness of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of the end of the period covered by this report pursuant to Rule 13a-15(b) under the Exchange Act. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of such period, the Company's disclosure controls and procedures are effective.

(b) Management's Annual Report on Internal Control over Financial Reporting

The Company's management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act). The Company's internal control over financial reporting is a process designed by, or under the supervision of, the Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America.

Management of the Company, under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the Company's internal control over financial reporting as of the end of the period covered by this report pursuant to Rule 13a-15(c) under the Exchange Act. Management's assessment was based on the framework established in *Internal Control-Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management has concluded that, as of December 31, 2013, the Company's internal control over financial reporting is effective.

The Company's internal control over financial reporting, as of December 31, 2013, has been audited by Deloitte & Touche LLP, the independent registered public accounting firm who audits the Company's consolidated financial statements, as stated in their report included in Item 8.—"Financial Statements and Supplementary Data," which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting, as of December 31, 2013.

(c) Changes in Internal Control over Financial Reporting

There have not been any changes in the Company's internal control over financial reporting during the fourth quarter of 2013 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION.

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

The information required by Item 10 is incorporated herein by reference to the relevant information under the captions "Section 16(a) Beneficial Ownership Reporting Compliance," "Corporate Governance," "Proposal 1: Election of Directors," and "Executive Officers" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on May 7, 2014.

ITEM 11. EXECUTIVE COMPENSATION.

The information required by Item 11 is incorporated herein by reference to the relevant information under the captions "Corporate Governance—Non-Employee Director Compensation," "Corporate Governance—Compensation Committee Interlocks and Insider Participation," "Compensation and Human Resources Committee Report," "Compensation Discussion and Analysis," and "Executive Compensation Tables" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on May 7, 2014.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

The information required by Item 12 is incorporated herein by reference to the relevant information under the captions "Security Ownership of Certain Beneficial Owners, Directors and Executive Officers" and "Equity Compensation Plans," in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on May 7, 2014.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

The information required by Item 13 is incorporated herein by reference to the relevant information under the caption "Corporate Governance" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on May 7, 2014.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

The information required by Item 14 is incorporated herein by reference to the relevant information under the captions "Principal Accountant Fees and Services" and "Pre-Approval Policy for Independent Auditor Services" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on May 7, 2014.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES.

(a) Financial Statements and Schedules

The financial statements are set forth under Item 8 of this Annual Report on Form 10-K. Financial statement schedules have been omitted since they are either not required, not applicable, or the information is otherwise included.

(b) Exhibit Listing

Exhibit Number	Description
(3)	**Articles of Incorporation and Bylaws**
3.1*	Second Amended and Restated Articles of Incorporation of Portland General Electric Company (Form 10-Q filed August 3, 2009, Exhibit 3.1).
3.2*	Ninth Amended and Restated Bylaws of Portland General Electric Company (Form 8-K filed October 27, 2011, Exhibit 3.1).
(4)	**Instruments defining the rights of security holders, including indentures**
4.1*	Portland General Electric Company Indenture of Mortgage and Deed of Trust dated July 1, 1945 (Form 8, Amendment No. 1 dated June 14, 1965) (File No. 001-05532-99).
4.2*	Fortieth Supplemental Indenture dated October 1, 1990 (Form 10-K for the year ended December 31, 1990, Exhibit 4) (File No. 001-05532-99).
4.3*	Fifty-sixth Supplemental Indenture dated May 1, 2006 (Form 8-K filed May 25, 2006, Exhibit 4.1) (File No. 001-05532-99).
4.4*	Fifty-seventh Supplemental Indenture dated December 1, 2006 (Form 8-K filed December 22, 2006, Exhibit 4.1) (File No. 001-05532-99).
4.5*	Fifty-eighth Supplemental Indenture dated April 1, 2007 (Form 8-K filed April 12, 2007, Exhibit 4.1) (File No. 001-05532-99).
4.6*	Fifty-ninth Supplemental Indenture dated October 1, 2007 (Form 8-K filed October 5, 2007, Exhibit 4.1) (File No. 001-05532-99).
4.7*	Sixtieth Supplemental Indenture dated April 1, 2008 (Form 8-K filed April 17, 2008, Exhibit 4.1).
4.8*	Sixty-first Supplemental Indenture dated January 15, 2009 (Form 8-K filed January 16, 2009, Exhibit 4.1).
4.9*	Sixty-second Supplemental Indenture dated April 1, 2009 (Form 8-K filed April 16, 2009, Exhibit 4.1).
4.10*	Sixty-third Supplemental Indenture dated November 1, 2009 (Form 8-K filed November 4, 2009, Exhibit 4.1).
4.11*	Sixty-seventh Supplemental Indenture dated June 15, 2013 (Form 8-K filed June 27, 2013, Exhibit 4.1).
4.12*	Sixty-eighth Supplemental Indenture dated October 15, 2013 (Form S-3 filed November 12, 2013, Exhibit 4.13).
(10)	**Material Contracts**
10.1*	Credit Agreement dated November 14, 2012, between Portland General Electric Company, Wells Fargo Bank, National Association, as Administrative Agent, JPMorgan Chase Bank, N.A. and U.S. Bank National Association, as Co-Syndication Agents, and a group of lenders (Form 10-K filed February 22, 2013, Exhibit 10.1).
10.2*	Credit Agreement dated December 8, 2011, between Portland General Electric Company, Bank of America, N.A., as Administrative Agent, Barclays Capital, as Syndication Agent, and a group of lenders (Form 10-K filed February 24, 2012, Exhibit 10.3).
10.3*	First Amendment dated April 10, 2012 to Credit Agreement dated December 8, 2011, between Portland General Electric Company, Bank of America, N.A., as Administrative Agent, and a group of lenders (Form 10-K filed February 22, 2013, Exhibit 10.3).

Exhibit Number	Description
10.4*	Second Amendment dated October 31, 2012 to Credit Agreement dated December 8, 2011, between Portland General Electric Company, Bank of America, N.A., as Administrative Agent, and a group of lenders (Form 10-K filed February 22, 2013, Exhibit 10.4).
10.5*	Third Amendment dated January 7, 2013 to Credit Agreement dated December 8, 2011, between Portland General Electric Company, Bank of America, N.A., as Administrative Agent, and a group of lenders (Form 10-K filed February 22, 2013, Exhibit 10.5).
10.6*	Confirmation of Forward Sale Transaction dated June 11, 2013 between Portland General Electric Company and Barclays Bank PLC (Form 8-K filed June 17, 2013, Exhibit 10.1).
10.7*	First Amendment to Confirmation Agreement dated June 25, 2013 between Portland General Electric Company and Barclays Bank PLC (Form 10-Q filed August 2, 2013, Exhibit 10.2).
10.8	Transfer Agreement between BA Leasing BSC, LLC, as Transferor, and Portland General Electric Company, as Transferee, dated December 18, 2013.
10.9*	Portland General Electric Company Severance Pay Plan for Executive Employees dated June 15, 2005 (Form 8-K filed June 20, 2005, Exhibit 10.1) (File No. 001-05532-99). +
10.10*	Portland General Electric Company Outplacement Assistance Plan dated June 15, 2005 (Form 8-K filed June 20, 2005, Exhibit 10.2) (File No. 001-05532-99). +
10.11*	Portland General Electric Company 2005 Management Deferred Compensation Plan dated January 1, 2005 (Form 10-K filed March 11, 2005, Exhibit 10.18) (File No. 001-05532-99). +
10.12*	Portland General Electric Company Management Deferred Compensation Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.1) (File No. 001-05532-99). +
10.13*	Portland General Electric Company Supplemental Executive Retirement Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.2) (File No. 001-05532-99). +
10.14*	Portland General Electric Company Senior Officers' Life Insurance Benefit Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.3) (File No. 001-05532-99). +
10.15*	Portland General Electric Company Umbrella Trust for Management dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.4) (File No. 001-05532-99). +
10.16*	Portland General Electric Company 2006 Stock Incentive Plan, as amended (Form 10-K filed February 27, 2008, Exhibit 10.23). +
10.17*	Portland General Electric Company 2006 Annual Cash Incentive Master Plan (Form 8-K filed March 17, 2006, Exhibit 10.1) (File No. 001-05532-99). +
10.18*	Portland General Electric Company 2006 Outside Directors' Deferred Compensation Plan (Form 8-K filed May 17, 2006, Exhibit 10.1) (File No. 001-05532-99). +
10.19*	Portland General Electric Company 2008 Annual Cash Incentive Master Plan for Executive Officers (Form 8-K filed February 26, 2008, Exhibit 10.1). +
10.20*	Form of Portland General Electric Company Agreement Concerning Indemnification and Related Matters (Form 8-K filed December 24, 2009, Exhibit 10.1). +
10.21*	Form of Portland General Electric Company Agreement Concerning Indemnification and Related Matters for Officers and Key Employees (Form 8-K filed February 19, 2010, Exhibit 10.1). +
10.22*	Form of Directors' Restricted Stock Unit Agreement (Form 8-K filed July 14, 2006, Exhibit 10.1) (File No. 001-05532-99). +
10.23*	Form of Officers' and Key Employees' Performance Stock Unit Agreement (Form 10-Q filed May 3, 2012, Exhibit 10.1). +
10.24*	Employment Agreement dated and effective May 6, 2008 between Stephen M. Quennoz and Portland General Electric Company (Form 10-Q filed May 7, 2008, Exhibit 10.3). +
(12)	**Statements Re Computation of Ratios**
12.1	Computation of Ratio of Earnings to Fixed Charges.
(23)	**Consents of Experts and Counsel**
23.1	Consent of Independent Registered Public Accounting Firm Deloitte & Touche LLP.
(31)	**Rule 13a-14(a)/15d-14(a) Certifications**
31.1	Certification of Chief Executive Officer.
31.2	Certification of Chief Financial Officer.
(32)	**Section 1350 Certifications**
32.1	Certifications of Chief Executive Officer and Chief Financial Officer.

Exhibit Number	Description
(101)	**Interactive Data File**
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

* Incorporated by reference as indicated.
\+ Indicates a management contract or compensatory plan or arrangement.

Certain instruments defining the rights of holders of other long-term debt of PGE are omitted pursuant to Item 601 (b)(4)(iii)(A) of Regulation S-K because the total amount of securities authorized under each such omitted instrument does not exceed 10% of the total consolidated assets of the Company and its subsidiaries. PGE hereby agrees to furnish a copy of any such instrument to the SEC upon request.

Upon written request to Investor Relations, Portland General Electric Company, 121 S.W. Salmon Street, Portland, Oregon 97204, the Company will furnish shareholders with a copy of any Exhibit upon payment of reasonable fees for reproduction costs incurred in furnishing requested Exhibits.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on February 13, 2014.

PORTLAND GENERAL ELECTRIC COMPANY

By: /s/ JAMES J. PIRO

James J. Piro

President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated on February 13, 2014.

Signature	Title
/s/ JAMES J. PIRO **James J. Piro**	*President, Chief Executive Officer, and Director* (principal executive officer)
/s/ JAMES F. LOBDELL **James F. Lobdell**	*Senior Vice President of Finance, Chief Financial Officer, and Treasurer* (principal financial and accounting officer)
/s/ JOHN W. BALLANTINE **John W. Ballantine**	*Director*
/s/ RODNEY L. BROWN, JR. **Rodney L. Brown, Jr.**	*Director*
/s/ JACK E. DAVIS **Jack E. Davis**	*Director*
/s/ DAVID A. DIETZLER **David A. Dietzler**	*Director*
/s/ KIRBY A. DYESS **Kirby A. Dyess**	*Director*
/s/ MARK B. GANZ **Mark B. Ganz**	*Director*
/s/ NEIL J. NELSON **Neil J. Nelson**	*Director*
/s/ M. LEE PELTON **M. Lee Pelton**	*Director*

EXHIBIT 31.1

CERTIFICATION

I, James J. Piro, certify that:

1. I have reviewed this Annual Report on Form 10-K of Portland General Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 13, 2014

/s/ JAMES J. PIRO

James J. Piro
President and
Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, James F. Lobdell, certify that:

1. I have reviewed this Annual Report on Form 10-K of Portland General Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 13, 2014

/s/ JAMES F. LOBDELL

James F. Lobdell
Senior Vice President of Finance, Chief Financial Officer, and Treasurer

EXHIBIT 32.1

**CERTIFICATIONS PURSUANT TO
18 U.S.C. SECTION 1350, AS ADOPTED
PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

We, James J. Piro, President and Chief Executive Officer, and James F. Lobdell, Senior Vice President of Finance, Chief Financial Officer and Treasurer, of Portland General Electric Company (the "Company"), hereby certify that the Company's Annual Report on Form 10-K for the year ended December 31, 2013, as filed with the Securities and Exchange Commission on February 14, 2014 pursuant to Section 13(a) of the Securities Exchange Act of 1934 (the "Report"), fully complies with the requirements of that section.

We further certify that the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ JAMES J. PIRO

James J. Piro
President and
Chief Executive Officer

Date: February 13, 2014

/s/ JAMES F. LOBDELL

James F. Lobdell
Senior Vice President of Finance,
Chief Financial Officer and
Treasurer

Date: February 13, 2014

2013 Accomplishments | The year was marked by many accomplishments for Portland General Electric. Here are a few of the highlights.

$105 million
Net income for the year

No.1 Rank for the number of renewable power customers and renewable energy sales in the nation

89.4% PGE's generating plant availability[1]

$1.25 billion
Planned investments in three new generation plants

836,070
Customers served as of Dec. 31

High customer satisfaction
Top quartile ranking for residential customers[2]; Top decile ranking for general business customers[2]; and No. 4 nationally for large key customers[3]

$1.6 million Amount contributed by employees and company match to the community through PGE's employee giving campaign

$447 million Debt and equity raised in 2013 to finance new projects, provide working capital and pay off other debt

80,000 safer students
PGE delivered safety presentations to K-6 students in the classroom and community

Readiness Center Facility now sits ready to support critical functions in extreme emergencies

1: Excludes Colstrip plant | 2. Market Strategies International 2013 Electric Utility Satisfaction Study | 3. TQS Research 2013 survey

Corporate Information

Board of Directors

Jack E. Davis
Chairman of the Board of Directors,
Portland General Electric;
Retired Chief Executive Officer,
Arizona Public Service Company

James J. Piro
President and Chief Executive Officer,
Portland General Electric

John W. Ballantine
Retired Executive Vice President
and Chief Risk Management Officer,
First Chicago NBD Corporation

Rodney L. Brown, Jr.
Managing Partner,
Cascadia Law Group PLLC

David A. Dietzler
Retired Pacific Northwest Partner
in Charge of Audit Practice, KPMG LLP

Kirby A. Dyess
Principal,
Austin Capital Management LLC

Mark B. Ganz
President and Chief Executive Officer,
Cambia Health Solutions, Inc.

Neil J. Nelson
President and Chief Executive Officer,
Siltronic Corporation

M. Lee Pelton
President, Emerson College

Charles W. Shivery
Retired Chairman, President and Chief
Executive Officer, Northeast Utilities

Kathryn J. Jackson*
Chief Technology Officer and Senior Vice
President of Research and Technology,
Westinghouse Electric Company LLC

Corporate Officers

James J. Piro
President and Chief Executive Officer

James F. Lobdell
Senior Vice President, Finance,
Chief Financial Officer and Treasurer

William O. Nicholson
Senior Vice President,
Customer Service, Transmission and
Distribution

Maria M. Pope
Senior Vice President, Power Supply and
Operations, and Resource Strategy

Arleen N. Barnett
Vice President, Human Resources,
Diversity and Inclusion, and Administration

O. Bruce Carpenter
Vice President, Distribution

Carol A. Dillin
Vice President, Customer Strategies and
Business Development

J. Jeffrey Dudley
Vice President, General Counsel,
Corporate Compliance Officer and
Assistant Secretary

Campbell A. Henderson
Vice President, Information Technology
and Chief Information Officer

Stephen M. Quennoz
Vice President, Nuclear and Power
Supply / Generation

W. David Robertson
Vice President, Public Policy

Kristin Stathis
Vice President, Customer Service
Operations

*Appointed to the Board of Directors effective as of April 26, 2014

Investor Information

Corporate Headquarters
Portland General Electric Company
121 SW Salmon Street
Portland, Oregon 97204
503.464.8000
Investors.PortlandGeneral.com

Transfer Agent
American Stock
Transfer & Trust Company
59 Maiden Lane
Plaza Level
New York, NY 10038
866.621.2788

Independent Auditors
Deloitte & Touche LLP
3900 U.S. Bancorp Tower
111 SW Fifth Avenue
Portland, Oregon 97204
503.222.1341

Form 10-K
A copy of the company's 2013 Annual Report on Form 10-K will be furnished, without charge, upon written request made to:

William Valach
Director, Investor Relations
121 SW Salmon Street
1WTC0509
Portland, Oregon 97204

You may also obtain a copy of the Form 10-K by calling Investor Relations at 503.464.8586 or by downloading a copy from the company's website at *Investors.PortlandGeneral.com.*

Market Information
Portland General Electric Company common stock trades on the New York Stock Exchange under the ticker symbol POR.

To vote online visit:
Investors.PortlandGeneral.com

IMAGES:

On cover, left to right:
Robert Thompson, Leadman Repairman;
Biglow Canyon Wind Farm;
Construction at Port Westward Unit 2;
Kevin Whitener, Engineer, Salem Smart Power Center

Inside shareholder letter (left):
Jim Piro, President and Chief Executive Officer;
Faraday Powerhouse, new penstocks

Inside shareholder letter (right):
Mathew Quigley, Engineer, Port Westward Unit 2

Inside 2013 Accomplishments, left to right:
Rosa Sambrano, Journeyman Meterman;
PGE crews doing restoration work

Back cover, left to right:
Larisa Seibel, Customer Service Representative;
Rodante Baysa, Financial Analyst, Volunteer

Portland General Electric

Corporate Headquarters
121 SW Salmon Street | Portland, Oregon 97204
PortlandGeneral.com