RE 54 e-FILING REPORT COVER SHEET

REPORT NAME: **PGE Annual Reports for the year ending December 31, 2011**

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

Report 54 B Oregon Supplement to FERC Form 1

Report 54 C Annual Report to Stockholders

OAR 860-027-0070

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

☐ Economic and Policy Analysis

☒ **Electric and Natural Gas Revenue Requirements**

☐ Electric Rates and Planning

☐ Utility Safety, Reliability & Security

☐ Administrative Hearings Division

Portland General Electric Company
121 SW Salmon Street • Portland, Oregon 97204
PortlandGeneral.com

April 27, 2012

Via E-Mail and US Mail

OPUC Filing Center
Oregon Public Utility Commission
550 Capitol Street NE, Ste. 215
Salem, OR 97301

RE: Report 54 – PGE Annual Reports for Year Ending 12-31-2011

Enclosed for filing are the following:

1) PGE Report Cover Sheet
2) PGE FERC Form 1;
3) PGE's Oregon Supplement to FERC Form 1; and
4) PGE's Annual Report to Stockholders

PGE has filed these forms electronically, and forwarded a hard copy of the FERC Form 1 and Oregon Supplement to Judy Johnson by U.S. Mail.

If you have any questions or require further information, please call me at 503.464.7580 or Launa Harmon at 503.464.7251.

Please direct all formal correspondence, questions, or requests to the following e-mail address: pge.opuc.filings@pgn.com.

Sincerely,

Launa Harmon for

Patrick G. Hager
Manager, Regulatory Affairs

Attachments

cc: Judy Johnson (US Mail)
FERC Form 1 and Oregon Supplement

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 2011/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	02 Year/Period of Report
Portland General Electric Company	End of 2011/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	06 Title of Contact Person
Kirk M. Stevens	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	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Maria M. Pope		
02 Title SVP, CFO and Treasurer	Maria M. Pope	04/10/2012

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 2011/Q4

LIST OF SCHEDULES (Electric Utility)

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

LIST OF SCHEDULES (Electric Utility) (continued)

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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".

Stockholders' Reports Check appropriate box:

[X] Two copies will be submitted

[ ] No annual report to stockholders is prepared

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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 sells electricity and natural gas in the wholesale market to utilities and energy marketers.

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 2011/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 2011/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	
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18	SunWay 3, LLC	Solar power generation	0.01	
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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 2011/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	634,573
2	Senior Vice President, Finance, Chief Financial	Maria M. Pope	434,455
3	Officer, and Treasurer		
4	Vice President, General Counsel and Corporate	J. Jeffrey Dudley	295,404
5	Compliance Officer		
6	Vice President, Nuclear and Power Supply/Generation	Stephen M. Quennoz	282,945
7	Vice President, Power Operations and	James F. Lobdell	278,816
8	Resource Strategy		
9	Vice President, Administration	Arleen N. Barnett	253,001
10	Senior Vice President, Customer Service,	William O. Nicholson	246,525
11	Transmission and Distribution		
12	Vice President, Customer Strategies and	Carol A. Dillin	244,124
13	Business Development		
14	Vice President, Information Technology and	Campbell A. Henderson	220,830
15	Chief Information Officer		
16	Vice President, Distribution	O. Bruce Carpenter	214,123
17	Vice President, Public Policy	W. David Robertson	209,714
18	Vice President, Customer Service Operations	Kristin A. Stathis	162,175
19	Senior Vice President, Customer Service,	Stephen R. Hawke	147,234
20	Transmission and Distribution		
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Schedule Page: 104 Line No.: 1 Column: c

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

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

Retired from position effective July 1, 2011.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	Chicago, Illinois
2	Private Investor, Retired from First Chicago NBD Corp.	
3	Rodney L. Brown, Jr.	Seattle, Washington
4	Managing Partner, Cascadia Law Group PLLC	
5	David A. Dietzler	Lake Oswego, Oregon
6	Retired Partner of KPMG LLP	
7	Kirby A. Dyess	Beaverton, Oregon
8	Principal, Austin Capital Management LLC	
9	Peggy Y. Fowler	Portland, Oregon
10	Retired Chief Executive Officer and President of	
11	Portland General Electric Company	
12	Mark B. Ganz	Portland, Oregon
13	President and Chief Executive Officer of	
14	Cambia Health Solutions (formerly The Regence Group)	
15	Corbin A. McNeill, Jr.	Jackson Hole, Wyoming
16	Chair of the Board of Portland General Electric Company,	
17	Retired Chairman and Chief Executive Officer of	
18	Exelon Corp.	
19	Neil J. Nelson	Portland, Oregon
20	President and Chief Executive Officer of Siltronic Corp.	
21	M. Lee Pelton	Boston, Massachusetts
22	President of Emerson College	
23	James J. Piro	Portland, Oregon
24	President and Chief Executive Officer of	
25	Portland General Electric Company	
26	Robert T. F. Reid	Vancouver, British Columbia, Canada
27	Retired Chair and Corporate Director of British Columbia	
28	Transmission Corporation	
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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 2011/Q4

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

Does the respondent have formula rates?

[ ] Yes
[X] No

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

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

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

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?

[ ] Yes
[X] No

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

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

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

Line No.	Page No(s).	Schedule	Column	Line No
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

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

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

1. None

2. None

3. None

4. None

5. None

6. Pursuant to PGE's application, the Federal Energy Regulatory Commission on December 28, 2011 issued an order in Docket No. ES12-04-000 that authorizes the Company to issue up to $700 million of short-term debt through February 6, 2014.

PGE has the following two unsecured revolving credit facilities that together provide a total of $670 million in available short-term financing: 1) a $370 million syndicated credit facility, of which $10 million and $360 million are scheduled to terminate in July 2012 and July 2013, respectively; and, 2) a $300 million syndicated credit facility, which is scheduled to terminate in December 2016.

PGE enters into financial agreements and power 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 PGE's historical experience and the evaluation of the specific indemnities. As of December 31, 2011, management believes the likelihood is remote that PGE would be required to perform under such indemnification provisions or otherwise incur any significant losses with respect to such indemnities. The Company has not recorded any liability on the Comparative Balance Sheet with respect to these indemnities.

7. None

8. None

9. Legal Proceedings:

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 Docket Nos. DR 10, UE 88, and UM 989, Marion County Oregon Circuit Court, Case No. 94C-10417, the Court of Appeals of the State of Oregon, the Oregon Supreme Court, Case No. SC S45653.

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. Oral arguments were made on February 3, 2012 and a decision by the Oregon Court of Appeals remains pending.

Dreyer, Gearhart and Kafoury Bros., LLC v. Portland General Electric Company, Marion County Circuit Court, Case No. 03C 10639; and Morgan v. Portland General Electric Company, Marion County Circuit Court, Case No. 03C 10640.

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, Docket Nos. EL01-10-000, et seq., and Ninth Circuit Court of Appeals, Case No. 03-74139 (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 September 2001, upon completion of hearings, the appointed administrative law judge issued a recommended order that the claims for refunds be dismissed. In December 2002, the FERC re-opened the case to allow parties to conduct further discovery. In June 2003, the FERC issued an order terminating the proceeding and denying the claims for refunds. In November 2003 and February 2004, the FERC denied all requests for rehearing of its June 2003 decision. 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 its 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 it 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. Two requests for rehearing were filed with the court and, in April 2009, the Ninth Circuit issued an order that denied the requests for rehearing and 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. 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. 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, contesting, among other things, the applicable refund period reflected in the Order, the use of the Mobile-Sierra standard, any restraints in the Order on the type of evidence that could be introduced in the hearing, and the lack of market-wide remedy. The rehearing requests remain pending.

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. The settlement proceedings are ongoing.

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.

10. None

11. (Reserved)

12. None

13. Changes in Officers:

Effective April 18, 2011, William O. Nicholson was appointed Senior Vice President, Customer Service, Transmission and Distribution.

Effective June 1, 2011, Kristin A. Stathis was appointed Vice President, Customer Service Operations.

Effective July 1, 2011, Stephen R. Hawke, resigned as Senior Vice President, Customer Service, Transmission and Distribution.

14. None

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	6,590,485,297	6,273,112,149
3	Construction Work in Progress (107)	200-201	119,814,163	124,966,713
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		6,710,299,460	6,398,078,862
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	3,067,218,653	2,858,431,769
6	Net Utility Plant (Enter Total of line 4 less 5)		3,643,080,807	3,539,647,093
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)		3,643,080,807	3,539,647,093
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		27,661,733	27,062,796
19	(Less) Accum. Prov. for Depr. and Amort. (122)		12,475,809	11,762,022
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	2,892,279	2,490,770
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)		73,642,418	79,153,262
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		831	3,083,458
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		91,721,452	100,028,264
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		4,968,250	3,810,683
36	Special Deposits (132-134)		80,219,447	83,203,795
37	Working Fund (135)		25,695	30,313
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		120,966,271	116,838,849
41	Other Accounts Receivable (143)		28,273,762	21,338,795
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		5,587,219	4,967,320
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		104,437	602,865
45	Fuel Stock (151)	227	33,794,768	21,503,107
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	32,662,190	30,786,477
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	6,081	6,081
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	360,000	360,000

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	4,659,816	2,944,884
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)		58,237,421	70,070,070
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)		101,146,935	92,802,931
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		19,409,497	15,546,066
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		831	3,083,458
65	Derivative Instrument Assets - Hedges (176)		0	112,663
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		479,246,520	451,906,801
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		11,251,311	13,502,264
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	987,024	3,368,428
72	Other Regulatory Assets (182.3)	232	784,667,938	755,788,489
73	Prelim. Survey and Investigation Charges (Electric) (183)		9,587,602	12,865,561
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)		197,376	66,543
77	Temporary Facilities (185)		9,498	1,706
78	Miscellaneous Deferred Debits (186)	233	15,752,414	12,829,644
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)		28,021,674	23,243,577
82	Accumulated Deferred Income Taxes (190)	234	387,648,270	407,943,476
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,238,123,107	1,229,609,688
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		5,452,171,886	5,321,191,846

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2011/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	828,591,553	823,989,481
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	15,302,074	15,302,074
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	8,076,622	8,034,721
11	Retained Earnings (215, 215.1, 216)	118-119	833,609,596	767,164,180
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-214,993	-616,911
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)	-6,078,989	-5,340,299
16	Total Proprietary Capital (lines 2 through 15)		1,663,132,619	1,592,463,804
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,736,400,000	1,809,000,000
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	107,806	113,786
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		1,099,639	1,318,880
24	Total Long-Term Debt (lines 18 through 23)		1,735,408,167	1,807,794,906
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)		8,834,000	8,177,406
29	Accumulated Provision for Pensions and Benefits (228.3)		300,067,805	241,043,851
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		20,017,327	10,762,646
32	Long-Term Portion of Derivative Instrument Liabilities		171,648,800	188,185,649
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		87,194,723	63,796,273
35	Total Other Noncurrent Liabilities (lines 26 through 34)		587,762,655	511,965,825
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		29,997,975	18,999,088
38	Accounts Payable (232)		181,211,138	162,840,577
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		582,855	406,624
41	Customer Deposits (235)		8,523,369	6,400,962
42	Taxes Accrued (236)	262-263	9,627,185	12,636,141
43	Interest Accrued (237)		23,678,160	25,810,201
44	Dividends Declared (238)		21,035,952	20,158,740
45	Matured Long-Term Debt (239)		0	0

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Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	end of 2011/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)		12,344,347	10,855,769
48	Miscellaneous Current and Accrued Liabilities (242)		9,569,472	12,087,549
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		387,235,892	376,162,423
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		171,648,800	188,185,649
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)		512,157,545	458,172,425
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		0	31,959
57	Accumulated Deferred Investment Tax Credits (255)	266-267	0	14,052
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	1,252,868	1,252,029
60	Other Regulatory Liabilities (254)	278	68,548,059	92,510,469
61	Unamortized Gain on Reaquired Debt (257)		90,585	98,637
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		553,945,938	519,679,362
64	Accum. Deferred Income Taxes-Other (283)		329,873,450	337,208,378
65	Total Deferred Credits (lines 56 through 64)		953,710,900	950,794,886
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		5,452,171,886	5,321,191,846

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	1,832,467,476	1,935,745,889		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,087,126,410	1,243,610,554		
5	Maintenance Expenses (402)	320-323	112,230,964	98,971,908		
6	Depreciation Expense (403)	336-337	211,052,942	208,952,082		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	3,119,928	272,063		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	19,275,881	17,223,182		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		3,500,278	4,646,000		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		9,627,903	4,869,775		
13	(Less) Regulatory Credits (407.4)		23,315,749	2,688,590		
14	Taxes Other Than Income Taxes (408.1)	262-263	96,561,192	89,639,509		
15	Income Taxes - Federal (409.1)	262-263	1,994,642	-20,267,757		
16	- Other (409.1)	262-263	357,919	125,385		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	299,660,928	250,778,481		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	242,341,993	181,110,741		
19	Investment Tax Credit Adj. - Net (411.4)	266				
20	(Less) Gains from Disp. of Utility Plant (411.6)			115,084		
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		662,783	745,800		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,579,514,028	1,715,652,567		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		252,953,448	220,093,322		

STATEMENT OF INCOME FOR THE YEAR (Continued)

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

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		Line No.
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	
						1
1,832,467,476	1,935,745,889					2
						3
1,087,126,410	1,243,610,554					4
112,230,964	98,971,908					5
211,052,942	208,952,082					6
3,119,928	272,063					7
19,275,881	17,223,182					8
						9
3,500,278	4,646,000					10
						11
9,627,903	4,869,775					12
23,315,749	2,688,590					13
96,561,192	89,639,509					14
1,994,642	-20,267,757					15
357,919	125,385					16
299,660,928	250,778,481					17
242,341,993	181,110,741					18
						19
	115,084					20
						21
						22
						23
662,783	745,800					24
1,579,514,028	1,715,652,567					25
252,953,448	220,093,322					26

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		252,953,448	220,093,322		
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)		202,114	189,506		
33	Revenues From Nonutility Operations (417)		3,574,305	5,543,676		
34	(Less) Expenses of Nonutility Operations (417.1)		2,794,300	4,809,942		
35	Nonoperating Rental Income (418)		1,898,239	1,955,204		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	401,918	374,350		
37	Interest and Dividend Income (419)		151,105	142,915		
38	Allowance for Other Funds Used During Construction (419.1)		4,625,954	13,224,534		
39	Miscellaneous Nonoperating Income (421)		-1,974,107	4,567,953		
40	Gain on Disposition of Property (421.1)		21,900			
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		5,702,900	20,809,184		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)		31,376	33,720		
45	Donations (426.1)		1,829,376	1,252,967		
46	Life Insurance (426.2)		326,324	-1,669,582		
47	Penalties (426.3)		254,500	-125,151		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		902,093	751,988		
49	Other Deductions (426.5)		-966,604	1,150,981		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		2,377,065	1,394,923		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	1,114,948	1,068,509		
53	Income Taxes-Federal (409.2)	262-263	-186,639	-299,085		
54	Income Taxes-Other (409.2)	262-263	-59,910	25,743		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	1,082,256	4,990,809		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	2,915,884	1,532,135		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)		14,052	47,943		
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-979,281	4,205,898		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		4,305,116	15,208,363		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		104,254,149	105,459,321		
63	Amort. of Debt Disc. and Expense (428)		2,544,142	2,528,412		
64	Amortization of Loss on Reaquired Debt (428.1)		2,501,553	2,498,040		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)		8,052	10,225		
67	Interest on Debt to Assoc. Companies (430)					
68	Other Interest Expense (431)		4,181,275	8,678,985		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		3,058,885	9,096,795		
70	Net Interest Charges (Total of lines 62 thru 69)		110,414,182	110,057,738		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		146,844,382	125,243,947		
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)		146,844,382	125,243,947		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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		763,311,385	716,561,173
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)		146,442,464	124,869,597
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	No Par Value	238	-79,997,048	(78,119,385)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-79,997,048	(78,119,385)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		829,756,801	763,311,385
	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 2011/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)		833,609,596	767,164,180
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-616,911	(991,261)
50	Equity in Earnings for Year (Credit) (Account 418.1)		401,918	374,350
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)		-214,993	(616,911)

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)	146,844,382	125,243,947
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	233,448,751	226,447,327
5	Amortization of Debt Discount	5,037,643	5,016,227
6	Amortization of Unrecovered Plant	3,500,278	4,646,000
7	Net Asset from Price Risk Management Activities	7,322,701	117,569,070
8	Deferred Income Taxes (Net)	55,485,307	73,126,414
9	Investment Tax Credit Adjustment (Net)	-14,052	-47,943
10	Net (Increase) Decrease in Receivables	-18,288,066	45,433,500
11	Net (Increase) Decrease in Inventory	-15,882,306	3,152,879
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	5,168,124	-10,721,852
14	Net (Increase) Decrease in Other Regulatory Assets	69,221,596	-90,613,542
15	Net Increase (Decrease) in Other Regulatory Liabilities	-14,707,729	-32,554,780
16	(Less) Allowance for Other Funds Used During Construction	4,625,954	13,224,534
17	(Less) Undistributed Earnings from Subsidiary Companies	401,918	374,350
18	Contribution to Pension Plan	-26,000,000	-30,000,000
19	Contribution to the voluntary employees' beneficiary association trust	-15,378,088	
20	Other: Margin and Customer Deposits	5,106,755	-25,896,362
21	Other Operating	12,745,797	-2,872,807
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	448,583,221	394,329,194
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-306,835,673	-450,386,736
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-598,937	-11,653
30	(Less) Allowance for Other Funds Used During Construction	-4,625,954	-13,224,534
31	Other (provide details in footnote):		
32	Other Capital Activities	4,540,134	-3,572,230
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-298,268,522	-440,746,085
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-401,509	-2,415,395
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48	Other Investments	2,589,857	-3,697,399
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Purchases of Trojan Decommissioning Trust Securities	-49,698,939	-45,814,740
54	Sales of Trojan Decoommissioning Trust Securities	46,326,879	49,959,991
55	Distribution from Trust Fund - Boardman Deferral		18,726,448
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-299,452,234	-423,987,180
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		249,400,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)	10,998,887	18,999,088
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	10,998,887	268,399,088
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-72,605,980	-186,170,199
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Premium paid on repayment of long-term debt	-7,279,650	
78	Net Decrease in Short-Term Debt (c)		
79	Debt Issue Cost		-1,770,431
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-79,091,295	-77,524,776
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-147,978,038	2,933,682
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	1,152,949	-26,724,304
87			
88	Cash and Cash Equivalents at Beginning of Period	3,840,996	30,565,300
89			
90	Cash and Cash Equivalents at End of period	4,993,945	3,840,996

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

On February 12, 2010, the OPUC issued an order (Order No. 10-051) authorizing the offset of the Boardman power cost deferral with the simultaneous amortization of an equal amount of customer credits related to nuclear decommissioning activities. Based on the OPUC order, $18,726,448 was transferred from the Nuclear decommissioning trust to PGE.

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.

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SEE PAGE 123 FOR REQUIRED INFORMATION.

Supplemental Disclosures

Supplemental Information to Statement of Cash Flows

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

	Balance at Beginning of Year	Balance at End of Year
Cash (131)	$ 3,810,683	$ 4,968,250
Working Funds (135)	30,313	25,695
Temporary Cash Investment (136)	-	-
	$ 3,840,996	$ 4,993,945

Cash paid during the year:	2010	2011
Interest	$106,609,092	$ 106,404,391
AFDC - Borrowed	(9,096,795)	(3,058,885)
	$ 97,512,297	$ 103,345,506
Income taxes	$ 100,200	$ 3,428,888

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, 2011, PGE served 822,466 retail customers with a service area population of approximately 1.7 million, comprising approximately 44% of the state's population.

As of December 31, 2011, PGE had 2,634 employees, with 840 employees covered under two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 804 and 36 employees and expire in February 2015 and August 2014, respectively.

PGE is subject to the jurisdiction of the Public Utility Commission of Oregon (OPUC) with respect to retail prices, utility services, accounting policies and practices, issuances of securities, and certain other matters. Retail prices are based on the Company's cost to serve customers, including an opportunity to earn a reasonable rate of return, as determined by the OPUC. The Company is also subject to regulation by the Federal Energy Regulatory Commission (FERC) in matters related to wholesale energy transactions, transmission services, reliability standards, natural gas pipelines, hydroelectric project licensing, accounting policies and practices, short-term debt issuances, and certain other matters.

Financial Statements

These financial statements have been prepared in accordance with the accounting requirements of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America (GAAP). As a result, the presentation of these financial statements differs from GAAP.

The primary differences include the requirement that PGE report its investments in majority-owned subsidiaries on the equity method rather than consolidating the assets, liabilities, revenues and expenses of the subsidiaries, as required by GAAP. In addition, the FERC requires that certain items on the Balance Sheet be classified differently than that required by GAAP, primarily the classification of current and non-current components of accumulated deferred income taxes, long-term debt, regulatory assets and liabilities, and the classification of Accumulated asset retirement removal costs.

The FERC also requires that certain items on the Statement of Income be classified differently than that required by GAAP. These include the requirement that all gains and losses on non-physical settlements of electricity derivative activities be recorded on a gross basis rather than on a net basis, as required by GAAP (for additional information, see Note 5 - Price Risk Management). In addition, certain items that are considered to be non-operating in nature are recorded in Other Deductions in the FERC Statement of Income but are recorded within Operating Expenses in financial statements prepared in accordance with GAAP.

Use of Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosures of gain or loss contingencies, as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ materially from those estimates.

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 none as of December 31, 2011 and 2010.

Accounts Receivable

Accounts receivable are recorded at invoiced amounts and do not bear interest when recorded. Late payment fees on balances in arrears are first assessed 16 business days after the due date. An inactive account balance is charged-off in the period in which the receivable is deemed uncollectible, but no sooner than 45 business days after the final due date.

Estimated provisions for uncollectible accounts receivable related to retail sales, charged to Administrative and general expenses, 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 of customer accounts, aging of accounts receivable, bad debt write-offs, actual customer billings, and other factors.

Provisions related to wholesale accounts receivable and unsettled positions, charged to Purchased Power, are based on a periodic review and evaluation that includes counterparty non-performance risk and contractual rights of offset when applicable. Actual amounts written off are charged to the allowance for uncollectible accounts.

Price Risk Management

PGE engages in price risk management activities, utilizing financial instruments such as forward, 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, unless they qualify for the normal purchases and normal sales exception. 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 meet the requirements for treatment under the normal purchases and normal sales exception. Other activities consist of certain electricity forwards, options and swaps, certain natural gas forwards, options, and swaps, and forward contracts for acquiring Canadian dollars. Such 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. Contracts that qualify for the normal purchases and normal sales exception are not required to be recorded at fair value. Unrealized gains and losses from contracts that qualify as cash flow hedges are recorded net in Other comprehensive income and contracts not designated as cash flow hedges are recorded net in Purchased Power on the statements of income.

Physical electricity sale and purchase transactions are recorded in Revenues and Purchased Power upon settlement, respectively.

Pursuant to transactions entered into in connection with PGE's price risk management activities, the Company may be required to provide collateral with certain counterparties. The collateral requirements are based on the contract terms and commodity prices and can vary period to period. Cash deposits provided as collateral are classified as Special deposits in the accompanying balance sheets and were $80 million and $83 million as of December 31, 2011 and 2010, respectively. Letters of credit provided as collateral are not recorded on the Company's balance sheet and were $104 million and $180 million as of December 31, 2011 and 2010, 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. Costs include 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 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.

PGE records AFDC, which is intended to represent the Company's cost of funds used for construction purposes and is based on the rate granted in the latest general rate case for equity funds and the cost of actual borrowings for debt funds. AFDC is capitalized as part of the cost of plant and credited to the statements of income. The average rate used by PGE was 8% in 2011 and 2010. AFDC from borrowed funds was $3 million in 2011 and $9 million in 2010 and is reflected as a reduction to Interest expense. AFDC from equity funds was $5 million in 2011 and $13 million in 2010 and is reflected as a component of Other income, net.

Costs which are disallowed for recovery in customer prices 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 2011 and 3.9% in 2010. Estimated asset retirement removal costs included in depreciation expense were $49 million in the year ended December 31, 2011 and $47 million in the year ended December 31, 2010.

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 every five years and are filed with the OPUC for approval and inclusion in a future rate proceeding. On September 13, 2010, PGE received an order from the OPUC authorizing new depreciation rates to be effective January 2011.

Thermal production 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):

Production, excluding thermal:	
Hydro	86
Wind	27
Transmission	53
Distribution	40
General	14

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 charged to AROs for assets that meet the definition of a legal obligation and to accumulated depreciation.

On June 21, 2011, PGE received an order from the OPUC authorizing an increase in customer prices effective July 1, 2011 for depreciation expense and decommissioning costs related to the Company's commitment to cease coal-fired operations at Boardman at the end of 2020.

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 $153 million and $133 million as of December 31, 2011 and 2010, respectively, with amortization expense of $19 million in 2011 and $17 million in 2010. Future estimated amortization expense as of December 31, 2011 is as follows: $20 million in 2012; $14 million in 2013; $12 million in 2014; $11 million in 2015; and $8 million in 2016.

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. 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 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.” If the difference between actual NVPC and baseline NVPC falls within the established deadband range, PGE absorbs the incremental cost or benefit, with the difference falling outside the lower and upper thresholds of the deadband range being shared 90/10 between customers and the Company, respectively. Any customer refund or collection is also subject to a regulated earnings test. A refund will occur only to the extent that it results in PGE’s actual regulated return on equity (ROE) for that year being no less than 1% above the Company’s latest authorized ROE. 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 last authorized ROE. PGE’s authorized ROE was 10% for 2011 and 2010. A final determination of any customer refund or collection is made by the OPUC through an annual public filing and review.

PGE estimates and records amounts related to the PCAM on a quarterly basis during the year. If the projected difference between baseline and actual NVPC for the year exceeds the established deadband, and if forecasted earnings exceed the level required by the regulated earnings test, a regulatory liability is recorded for any future amount payable to retail customers, with offsetting amounts recorded to Purchased Power. If the difference is below the lower end of the deadband, a regulatory asset is recorded for any future amount due from retail customers.

For 2011, the deadband ranged from $15 million below to $30 million above baseline NVPC. PGE’s actual NVPC as determined pursuant to the PCAM for 2011 was below baseline NVPC by $34 million, which is $19 million below the lower deadband threshold. For 2011, PGE recorded an estimated refund to customers of $10 million, 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 will be made by the OPUC through a public filing and review in 2012.

For 2010, the deadband ranged from $17 million below to $35 million above baseline NVPC. Although PGE's actual NVPC as determined pursuant to the PCAM for 2010 was below baseline NVPC by $12 million, it was within the established deadband range and, accordingly, no customer refund was recorded in 2010. A final determination regarding the 2010 PCAM results was made by the OPUC through a public filing and review in 2011, which concluded that no customer refund was warranted for 2010.

Asset Retirement Obligations

An ARO is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. PGE recognizes those legal obligations related to dismantlement and restoration costs associated with the future retirement of tangible long-lived assets. 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 removal expenditures is capitalized as an ARO on the balance sheets and 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.

Contingencies

Contingencies are evaluated using the best information available at the time the financial statements are prepared. Loss contingencies are accrued and disclosed 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 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) is comprised of the difference between the non-qualified benefit plans' obligations recognized in net income and the unfunded position as of December 31, 2011 and 2010.

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 Revenues, net and amounts due to taxing authorities are included in Taxes other than income taxes and totaled $41 million in 2011 and $39 million in 2010.

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 accrues 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 service 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 $87 million and $95 million as of December 31, 2011 and 2010, respectively, and will be included in prices when the temporary differences reverse.

Investment tax credits utilized were deferred and amortized to income over the lives of the related properties, and were fully amortized by the end of 2011.

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 sheet.

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

Recent Accounting Pronouncements

Accounting Standards Update (ASU) 2010-06, *Fair Value Measurements and Disclosures (Topic 820) - Improving Disclosures about Fair Value Measurements* (ASU 2010-06) requires, among other matters, separate reporting about purchases, sales, issuances, and settlements for Level 3 fair value measurements. For additional information on Level 3, see Note 4, Fair Value of Financial Instruments. In accordance with the provisions of ASU 2010-06, PGE adopted this requirement of ASU 2010-06 on January 1, 2011, which did not have a material impact on the Company’s financial position, results of operations, or cash flows. All other requirements of ASU 2010-06 were adopted on January 1, 2010 in accordance with ASU 2010-06.

In May 2011, ASU 2011-04, *Fair Value Measurements and Disclosures (Topic 820) - Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs* (ASU 2011-04) was issued. Many of the amendments in ASU 2011-04 change the wording used to describe principles and requirements to align with International Financial Reporting Standards as issued by the International Accounting Standards Board, and are not intended to change the application of Topic 820. Some of the amendments clarify the Financial Accounting Standards Board’s intent on the application of existing fair value guidance or change a particular principle or requirement for measuring fair value or fair value disclosures. The amendments in ASU 2011-04 are to be applied prospectively and are effective for interim and annual periods beginning after December 15, 2011 for public entities, with early application not permitted. PGE will adopt the amendments contained in ASU 2011-04 on January 1, 2012, which are not expected to have a material impact on the Company’s financial position, results of operations, or cash flows.

In June 2011, ASU 2011-05, *Comprehensive Income (Topic 220) - Presentation of Comprehensive Income* (ASU 2011-05) was issued. The amendments of ASU 2011-05 require, among other things, that an entity report items of other comprehensive income in one of two ways: (i) a single statement with components of net income and total net income, the components of other comprehensive income and total other comprehensive income, and a total for comprehensive income; or (ii) two statements with components of net income and total net income in the first statement, immediately followed by a statement that presents the components of other comprehensive income, a total for other comprehensive income, and a total for comprehensive income. The amendments in ASU 2011-05 are to be applied retrospectively and are effective for interim and annual periods beginning after December 15, 2011, with early application permitted. PGE adopted the amendments contained in ASU 2011-05 on December 31, 2011, which had no impact on the Company’s financial position, results of operations, or cash flows.

In December 2011, ASU 2011-12, *Comprehensive Income (Topic 220) - Presentation of Comprehensive Income* (ASU 2011-12) was issued and defers only the changes in ASU 2011-05 that relate to the presentation of reclassification adjustments, which pertain to how and where reclassification adjustments are presented. ASU 2011-12 is effective at the same time as ASU 2011-05. Accordingly, PGE adopted the amendments contained in ASU 2011-12 on December 31, 2011, which had no impact on the Company’s financial position, results of operations, or cash flows.

NOTE 3: BALANCE SHEET COMPONENTS

Accounts Receivable, Net

The following is the activity in the Accumulated Provision for Uncollectible Accounts (Account 144), in millions:

	Years Ended December 31, 2011	Years Ended December 31, 2010
Balance as of beginning of year	$ 5	$ 5
Increase in provision	11	7
Amounts written off, less recoveries	(10)	(7)
Balance as of end of year	$ 6	$ 5

Trust Accounts

PGE maintains two trust accounts as follows:

Nuclear decommissioning trust—Reflects assets held in trust to cover general decommissioning costs and operation of the Independent Spent Fuel Storage Installation (ISFSI) and represent amounts collected from customers less qualified expenditures plus any realized and unrealized gains and losses on the investments held therein.

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	
	2011	2010	2011	2010
Cash equivalents	$ 14	$ 13	$ —	$ —
Marketable securities, at fair value:				
Equity securities	—	—	10	19
Debt securities	23	21	3	2
Insurance contracts, at cash surrender value	—	—	23	23
	$ 37	$ 34	$ 36	$ 44

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,	
	2011	**2010**
Other current assets:		
Current deferred income tax asset	$ 33	$ —
Assets from price risk management activities	19	13
Income taxes receivable	12	22
Other	34	32
	$ 98	$ 67
Accrued expenses and other current liabilities:		
Accrued employee compensation and benefits	$ 44	$ 36
Accrued interest payable	24	26
Dividends payable	21	20
Other	62	63
	$ 151	$ 145

Other Noncurrent Assets

The Company incurs preliminary engineering costs related to potential future capital projects, which are capitalized in Other noncurrent assets in the balance sheets. Preliminary engineering costs consist of expenditures for preliminary surveys, plans, and investigations made for the purpose of determining the feasibility of utility projects being considered. Once the project is approved for construction, such costs are reclassified to Electric utility plant. If the project is abandoned, such costs are expensed to Production and distribution expense in the period such determination is made. If any preliminary engineering 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. As of December 31, 2011 and 2010, PGE has recorded preliminary engineering costs of $10 million and $13 million, respectively. For the years ended December 31, 2011 and 2010, no material preliminary engineering costs were expensed.

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, 2011 and 2010, and then classified 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 any transfers between levels in the fair value hierarchy as of the end of the reporting period. 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, except those net transfers out of Level 3 to Level 2 presented in this note, for the years ended December 31, 2011 and 2010.

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, 2011			
	Level 1	**Level 2**	**Level 3**	**Total**
Assets:				
Nuclear decommissioning trust (1):				
Money market funds	$ —	$ 14	$ —	$ 14
Debt securities:				
Domestic government	3	9	—	12
Corporate credit	—	11	—	11
Non-qualified benefit plan trust (2):				
Equity securities:				
Domestic	7	2	—	9
International	1	—	—	1
Debt securities - domestic government	3	—	—	3
Assets from price risk management activities (1) (3):				
Electricity	—	2	—	2
Natural gas	—	17	—	17
	$ 14	$ 55	$ —	$ 69
Liabilities - Liabilities from price risk management activities (1) (3):				
Electricity	$ —	$ 108	$ 29	$ 137
Natural gas	—	201	50	251
	$ —	$ 309	$ 79	$ 388

(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.

	As of December 31, 2010			
	Level 1	Level 2	Level 3	Total
Assets:				
Nuclear decommissioning trust (1):				
Money market funds	$ —	$ 13	$ —	$ 13
Debt securities:				
Domestic government	3	9	—	12
Corporate credit	—	9	—	9
Non-qualified benefit plan trust (2):				
Equity securities:				
Domestic	16	—	—	16
International	2	1	—	3
Debt securities - domestic government	2	—	—	2
Assets from price risk management activities (1) (3):				
Electricity	—	4	1	5
Natural gas	—	11	—	11
	$ 23	$ 47	$ 1	$ 71
Liabilities - Liabilities from price risk management activities (1) (3):				
Electricity	$ —	$ 102	$ 17	$ 119
Natural gas	—	153	104	257
	$ —	$ 255	$ 121	$ 376

(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 allocated to 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 held in the Nuclear decommissioning trust 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 securities are classified as Level 1 in the fair value hierarchy due to the highly observable nature of the pricing in an active market.

Fair values for municipal debt and corporate credit securities are classified as Level 2 as 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 as pricing inputs are based on unadjusted prices in an active market. Principal markets for equity prices include published exchanges such as NASDAQ and the New York Stock Exchange (NYSE), both American stock exchanges. 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 may not be directly 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 exchange rate risk, mitigate the effects of market fluctuations, and manage 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 quoted forward prices for commodities and interest rates. Substantially all of these assumptions 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 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 over-the-counter forward and swap derivatives. Commodity option contracts whose fair value is derived using standardized valuation techniques, such as Black-Scholes, are also classified as Level 3. Inputs into the valuation of commodity option contracts include forward commodity pricing, forward interest rates, and historic volatilities and correlations.

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 for the year ended December 31, 2011 (in millions):

Net liabilities from price risk management activities as of December 31, 2010	$	120
Net realized and unrealized losses (1)		86
Purchases		3
Settlements		(1)
Net transfers out of Level 3 to Level 2		(129)
Net liabilities from price risk management activities as of December 31, 2011	$	79
Level 3 net unrealized losses that have been fully offset by the effect of regulatory accounting	$	88

(1) Contains nominal amounts of realized losses, net.

The comparable information contained in the preceding table was as follows for the year ended December 31 2010 (in millions):

Net liabilities from price risk management activities as of beginning of year	$	154
Net realized and unrealized losses (1)		65
Purchases, issuances, and settlements, net		27
Net transfers out of Level 3 to Level 2		(126)
Net liabilities from price risk management activities as of end of year	$	120
Level 3 net unrealized losses that have been fully offset by the effect of regulatory accounting	$	95

(1) Contains nominal amounts of realized losses, net.

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. Transfers out of Level 3 occur when the significant inputs become more observable, such as 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.

Long-term debt is recorded at amortized cost in PGE's balance sheets. The fair value of long-term debt 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, 2011, the estimated aggregate fair value of PGE's long-term debt was $2,091 million, compared to its $1,735 million carrying amount. As of December 31, 2010, the estimated aggregate fair value of PGE's long-term debt was $1,968 million, compared to its $1,808 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, 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 realized. This accounting treatment defers the fair value gains and losses on derivative activities 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 has elected to report gross on the balance sheet the positive and negative exposures resulting from derivative instruments entered into with counterparties where a master netting arrangement exists. As of December 31, 2011 and 2010, the Company had $26 million and $31 million, respectively, in collateral posted with these counterparties, consisting entirely of letters of credit.

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 2015, were as follows (in millions):

	As of December 31,					
	2011			**2010**		
Commodity contracts:						
Electricity		13	MWh		9	MWh
Natural gas		79	Decatherms		93	Decatherms
Foreign currency exchange	$	6	Canadian	$	7	Canadian

The fair values of PGE's Assets and Liabilities from price risk management activities consist of the following (in millions):

	As of December 31,	
	2011	**2010**
Current assets:		
Commodity contracts:		
Electricity	$ 2	$ 4
Natural gas	17	9
Total current derivative assets	19	13
Noncurrent assets:		
Commodity contracts:		
Electricity	—	1
Natural gas	—	2
Total noncurrent derivative assets	—	3
Total derivative assets not designated as hedging instruments	$ 19	$ 16
Total derivative assets	$ 19	$ 16
Current liabilities:		
Commodity contracts:		
Electricity	$ 66	$ 77
Natural gas	150	111
Total current derivative liabilities	216	188
Noncurrent liabilities:		
Commodity contracts:		
Electricity	71	42
Natural gas	101	146
Total noncurrent derivative liabilities	172	188
Total derivative liabilities not designated as hedging instruments	$ 388	$ 376
Total derivative liabilities	$ 388	$ 376

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,	
	2011	**2010**
Commodity contracts:		
Electricity	$ 117	$ 127
Natural Gas	98	192

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, 2011 and 2010, $192 million and $258 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, 2011 related to PGE's derivative activities would be realized as a result of the settlement of the underlying derivative instrument (in millions):

	2012	2013	2014	2015	Total
Commodity contracts:					
Electricity	$ 64	$ 42	$ 21	$ 8	$ 135
Natural gas	132	72	24	6	234
Net unrealized loss	$ 196	$ 114	$ 45	$ 14	$ 369

The Company's secured and unsecured debt is currently rated at investment grade by Moody's Investors Service (Moody's) and Standard and 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, 2011 was $321 million, for which the Company had $104 million in posted collateral, consisting entirely of letters of credit. If the credit-risk-related contingent features underlying these agreements were triggered at December 31, 2011, the cash requirement to either post as collateral or settle the instruments immediately would have been $302 million.

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

	As of December 31,	
	2011	2010
Assets from price risk management activities:		
Counterparty A	19%	1%
Counterparty B	16	1
Counterparty C	13	5
Counterparty D	7	22
Counterparty E	7	23
Counterparty F	—	11
Counterparty G	—	10
	62%	73%
Liabilities from price risk management activities:		
Counterparty E	23%	24%
Counterparty H	10	4
Counterparty I	7	12
	40%	40%

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, 2011		As of December 31, 2010	
Regulatory assets:					
Price risk management (2)	2 years	$	365	$	360
Pension and other postretirement plans (2)	(3)		295		213
Deferred income taxes (2)	(4)		91		112
Deferred broker settlements (2)	1 year		11		24
Renewable energy deferral	1 year		1		22
Other (5)	Various		22		25
Total regulatory assets		$	785	$	756
Regulatory liabilities:					
Asset retirement obligations (6)	(4)	$	36	$	33
Power Cost Adjustment Mechanism	(7)		10		—
Trojan ISFSI pollution control tax credits	(7)		7		22
Other	Various		16		38
Total regulatory liabilities		$	69	$	93

(1) As of December 31, 2011.
(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 $21 million and $26 million as of December 31, 2011 and 2010, respectively.
(6) Included in rate base for ratemaking purposes.
(7) Refund period not yet determined.

As of December 31, 2011, PGE had regulatory assets of $22 million earning a return on investment at the following rates: (i) $7 million at PGE's authorized cost of capital, currently 8.033%; (ii) $7 million at the approved rate for deferred accounts under amortization, ranging from 2.01% to 4.27%, depending on the year of approval; and (iii) $8 million earning a return by inclusion in rate base.

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. During the fourth quarter of 2011, PGE received an order from the OPUC on its Annual Update Tariff for 2012 net variable power costs (NVPC). Pursuant to the order, the OPUC reduced the Company's 2012 NVPC forecast by approximately $3 million, which is reflected as a reduction to the regulatory asset for price risk management as of December 31, 2011. 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 represent 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.

Renewable energy deferral reflects the net revenue requirement related to new renewable resources and associated transmission that are not yet included in customer prices, with the majority related to Biglow Canyon Wind Farm. Recovery of net revenue requirements associated with new renewable resources, which are required by the 2007 Oregon Renewable Energy Act, is allowed under a renewable adjustment clause mechanism authorized 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.

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, which are included in Other noncurrent liabilities in the balance sheets, consist of the following (in millions):

	As of December 31,	
	2011	**2010**
Trojan decommissioning activities	$ 37	$ 38
Utility plant	38	16
Non-utility property	12	10
Asset retirement obligations	$ 87	$ 64

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 Independent Spent Fuel Storage Installation (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 permanent off-site storage is available. Decommissioning of the ISFSI and final site restoration activities will begin once shipment of all the spent fuel to a U.S. 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 are seeking approximately $128 million in damages. PGE's share of any recovery would be approximately 67%. A trial before the U.S. Court of Federal Claims commenced in the fourth quarter of 2011, with a decision expected during 2012. However, if the Plaintiffs were to prevail, the USDOE would likely appeal, which would defer any damage payment indefinitely. The Trojan ARO will not be impacted by the outcome of this case as such potential recovery is for past decommissioning costs and the ARO reflects only future decommissioning expenditures. Any proceeds received related to this legal matter would be returned to customers to offset amounts previously collected in relation to Trojan decommissioning activities.

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, as well as the Bull Run hydro project. Decommissioning work has been substantially completed at Bull Run, with only environmental monitoring continuing through 2012.

During 2011, an updated decommissioning study for PGE's Boardman coal-fired plant 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 balance sheet. Such transaction is non-cash and is excluded from investing activities in the statement cash flows for the year ended December 31, 2011.

Non-utility property primarily represents ARO's 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,	
	2011	**2010**
Balance as of beginning of year	$ 64	$ 63
Liabilities incurred	1	1
Liabilities settled	(4)	(3)
Accretion expense	4	4
Revisions in estimated cash flows	22	(1)
Balance as of end of year	$ 87	$ 64

Pursuant to regulation, the amortization of utility plant AROs is included in depreciation expense and in customer prices. Any differences in the timing of recognition of costs for financial reporting and ratemaking purposes are deferred as a regulatory asset or regulatory liability. Recovery of Trojan decommissioning costs is included in PGE's retail prices, currently at approximately $4 million annually, with an equal amount recorded in Depreciation and amortization expense.

PGE maintains a separate trust account, Nuclear decommissioning trust in the balance sheet, for funds collected from customers through prices to cover the cost of Trojan decommissioning activities. See “Trust Accounts” in Note 3, Balance Sheet Components, for additional information on the Nuclear decommissioning trust.

The Oak Grove hydro facility and transmission and distribution plant located on public right-of-ways and on certain easements meet the requirements of a legal obligation and will require removal when the plant is no longer in service. An ARO liability is not currently measurable as management believes that these assets will be used in utility operations for the foreseeable future. Removal costs are charged to accumulated asset retirement removal costs, which is included in Regulatory liabilities on PGE’s balance sheets.

NOTE 8: REVOLVING CREDIT FACILITIES

PGE has two unsecured revolving credit facilities, with an aggregate borrowing capacity of $670 million, as follows:

> A $370 million syndicated credit facility, of which $10 million is scheduled to terminate in July 2012 and $360 million in July 2013;
>
> A $300 million syndicated credit facility, which is scheduled to terminate in December 2016.

Pursuant to the terms of the agreements, both 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 credit facilities 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, 2011, PGE was in compliance with this covenant with a 51.5% debt ratio.

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

Pursuant to an order issued by the FERC, the Company is authorized to issue short-term debt up to $700 million through February 6, 2014. The authorization provides that if utility assets financed by unsecured debt are divested, then a proportionate share of the unsecured debt must also be divested.

As of December 31, 2011, PGE had no borrowings and $30 million in commercial paper outstanding under the credit facilities, with $124 million in letters of credit issued. As of December 31, 2011, the aggregate unused available credit under the credit facilities is $516 million.

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

	Years Ended December 31,	
	2011	2010
Average daily amount of short-term debt outstanding	$ 2	$ 9
Weighted daily average interest rate *	0.4%	0.4%
Maximum amount outstanding during the year	$ 44	$ 51

* 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, 2011	As of December 31, 2010
First Mortgage Bonds, rates range from 3.46% to 9.31%, with a weighted average rate of 5.83% in 2011 and 5.85% in 2010, due at various dates through 2040	$ 1,615	$ 1,678
Pollution Control Revenue Bonds:		
Port of Morrow, Oregon, 5% rate, due 2033	23	23
City of Forsyth, Montana, 5% rate, due 2033	119	119
Port of St. Helens, Oregon, 5.25% rate, due in 2014	—	10
Total Pollution Control Revenue Bonds	142	152
Pollution Control Revenue Bonds owned by PGE	(21)	(21)
Unamortized debt discount	(1)	(1)
Total long-term debt	$ 1,735	$ 1,808

First Mortgage Bonds—The Indenture securing PGE's First Mortgage Bonds constitutes a direct first mortgage lien on substantially all regulated utility property, other than expressly excepted property. On December 29, 2011, PGE redeemed $63 million of the 6.5% series due 2014.

Pollution Control Revenue Bonds—PGE has the option to remarket Pollution Control Revenue Bonds held by the Company through 2033. 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 and could be backed by first mortgage bonds or a bank letter of credit depending on market conditions.

As of December 31, 2011, the future minimum principal payments on long-term debt are as follows (in millions):

Years ending December 31:	
2012	$ 100
2013	100
2014	—
2015	70
2016	67
Thereafter	1,398
	$ 1,735

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. Such closure did not change the benefits provided to existing participants under the plan.

The assets of the pension plan are held in a trust and are comprised of equity, debt, and alternative asset investment vehicles, 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.

During 2011 and 2010, PGE made contributions to the pension plan of $26 million and $30 million, respectively. No contributions to the pension plan are expected in 2012.

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, 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 (SERP), 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. The Company also provides two retired employees with death benefits through a split dollar life insurance policy which pays a fixed amount to the beneficiary and for which the Company has a security interest for the amount of premiums paid. 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):

	2011			2010		
	NQBP	Other NQBP	Total	NQBP	Other NQBP	Total
Non-qualified benefit plan trust	$ 17	$ 19	$ 36	$ 19	$ 25	$ 44
Non-qualified benefit plan liabilities *	25	76	101	24	73	97

* For the NQBP, excludes the current portion of $2 million in 2011 and 2010, which is classified in Other current liabilities in the 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,			
	2011		2010	
	Actual	Target *	Actual	Target *
Defined Benefit Pension Plan:				
Equity securities	68%	67%	68%	67%
Debt securities	32	33	32	33
Total	100%	100%	100%	100%
Other Postretirement Benefit Plans:				
Equity securities	61%	72%	46%	47%
Debt securities	39	28	54	53
Total	100%	100%	100%	100%
Non-Qualified Benefits Plans:				
Equity securities	30%	23%	42%	42%
Debt securities	7	14	5	7
Insurance contracts	63	63	53	51
Total	100%	100%	100%	100%

* The Target for the Defined Benefit 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):

	As of December 31, 2011			
	Level 1	Level 2	Level 3	Total
Defined Benefit Pension Plan assets:				
Money market funds	$ —	$ 3	$ —	$ 3
Equity securities:				
Domestic	151	12	—	163
International	54	51	—	105
Debt securities:				
Domestic government and corporate credit	—	78	—	78
Corporate credit	76	—	—	76
Private equity funds	—	—	32	32
Alternative investments	—	—	30	30
	$ 281	$ 144	$ 62	$ 487
Other Postretirement Benefit Plans assets:				
Money market funds	$ —	$ 7	$ —	$ 7
Equity securities:				
Domestic	12	1	—	13
International	2	2	—	4
Debt securities—Domestic government	3	—	—	3
	$ 17	$ 10	$ —	$ 27

	As of December 31, 2010			
	Level 1	**Level 2**	**Level 3**	**Total**
Defined Benefit Pension Plan assets:				
Money market funds	$ —	$ 15	$ —	$ 15
Equity securities:				
Domestic	52	111	—	163
International	53	53	—	106
Debt securities—Domestic government and corporate credit	68	70	—	138
Private equity funds	—	—	23	23
Alternative investments	—	—	28	28
	$ 173	$ 249	$ 51	$ 473
Other Postretirement Benefit Plans assets:				
Money market funds	$ —	$ 7	$ —	$ 7
Equity securities:				
Domestic	3	2	—	5
International	1	1	—	2
Debt securities—Domestic government	2	—	—	2
	$ 6	$ 10	$ —	$ 16

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—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.

Alternative investments—Investments in a portable alpha strategy are comprised of long positions in S&P 500 futures contracts and a hedge fund-of-funds comprised of diversified group, by sector and market capitalization of long only, short only and/or both long/short equity hedge funds. Valuation of hedge funds included within this vehicle is provided by fund managers using unobservable internally modeled inputs. PGE performs validation procedures of manager performance by comparing stated performance against published benchmarks. Alternative investments are classified as level 3 due to lack of observable market inputs and relative illiquidity of the fund.

Changes in the fair value of assets held by the pension plan classified as Level 3 in the fair value hierarchy presented in the table above were as follows for the years ended December 31, 2011 and 2010 (in millions):

	Private equity	**Alternative assets**	**Total Level 3**
Balance as of December 31, 2009	$ 17	$ 23	$ 40
Purchases and sales, net	4	2	6
Realized gain on sales	1	—	1
Unrealized gain on assets	1	3	4
Balance as of December 31, 2010	23	28	51
Purchases	7	—	7
Realized loss on sales	(2)	—	(2)
Unrealized gain on assets	4	2	6
Balance as of December 31, 2011	$ 32	$ 30	$ 62

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, 2011 and 2010. Obligations related to the Other NQBP are not included in the following tables (dollars in millions):

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2011	2010	2011	2010	2011	2010
Benefit obligation:						
As of January 1	$ 550	$ 491	$ 79	$ 77	$ 25	$ 27
Service cost	12	11	2	2	—	—
Interest cost	29	28	4	4	1	1
Participants' contributions	—	—	2	2	—	—
Actuarial loss (gain)	69	42	(5)	1	3	—
Benefit payments	(26)	(22)	(7)	(7)	(2)	(3)
As of December 31	$ 634	$ 550	$ 75	$ 79	$ 27	$ 25
Fair value of plan assets:						
As of January 1	$ 473	$ 406	$ 16	$ 19	$ 19	$ 20
Actual return on plan assets	14	59	—	1	—	2
Company contributions	26	30	16	1	—	—
Participants' contributions	—	—	2	2	—	—
Benefit payments	(26)	(22)	(7)	(7)	(2)	(3)
As of December 31	$ 487	$ 473	$ 27	$ 16	$ 17	$ 19
Unfunded position as of December 31	$ (147)	$ (77)	$ (48)	$ (63)	$ (10)	$ (6)
Accumulated benefit plan obligation as of December 31	$ 566	$ 503	N/A	N/A	$ 27	$ 25

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2011	2010	2011	2010	2011	2010
Amounts included in comprehensive income:						
Net actuarial loss (gain)	$ 97	$ 22	$ (4)	$ 1	$ 2	$ —
Amortization of net actuarial loss	(8)	(3)	(1)	(1)	(1)	(1)
Amortization of prior service cost	(1)	(1)	(1)	(1)	—	—
	$ 88	$ 18	$ (6)	$ (1)	$ 1	$ (1)
Amounts included in AOCL*:						
Net actuarial loss	$ 275	$ 186	$ 15	$ 20	$ 10	$ 9
Prior service cost	1	2	4	5	—	—
	$ 276	$ 188	$ 19	$ 25	$ 10	$ 9
Assumptions used:						
Discount rate used to calculate benefit obligation	5.00%	5.47%	3.76% - 4.90%	4.02% - 5.40%	5.00%	5.47%
Weighted average rate of increase in future compensation levels	3.71%	3.80%	4.58%	4.83%	N/A	N/A
Long-term rate of return on plan assets	8.25%	8.50%	7.09%	6.44%	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	
	2011	2010	2011	2010	2011	2010
Service cost	$ 12	$ 11	$ 2	$ 2	$ —	$ —
Interest cost on benefit obligation	29	28	4	4	1	1
Expected return on plan assets	(42)	(39)	(1)	(1)	—	—
Amortization of prior service cost	1	1	1	1	—	—
Amortization of net actuarial loss	8	3	1	1	1	1
Net periodic benefit cost	$ 8	$ 4	$ 7	$ 7	$ 2	$ 2

PGE estimates that $20 million will be amortized from AOCL into net periodic benefit cost in 2012, 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					
	2012	**2013**	**2014**	**2015**	**2016**	**2017 - 2021**
Defined benefit pension plan	$ 31	$ 32	$ 34	$ 36	$ 37	$ 209
Other postretirement benefits	4	4	4	4	5	23
Non-qualified benefit plans	2	2	2	3	2	11
Total	$ 37	$ 38	$ 40	$ 43	$ 44	$ 243

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 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; and

For 2010, 8% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2011 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, and would increase or decrease the postretirement benefit obligation by less than $1 million.

401(k) Retirement Savings Plan

PGE sponsors a 401(k) Plan that covers substantially all employees. For eligible employees hired prior to February 1, 2009, the Company matches employee contributions up to 6% of the participating employee’s base pay. For eligible employees hired after January 31, 2009, and/or who are not otherwise covered by a defined benefit pension plan, PGE matches up to 5% of the participating employee’s base salary and, whether or not an employee contributes to the 401(k) Plan, the Company contributes 5% of the employee’s base salary.

For bargaining employees, who are subject to the International Brotherhood of Electrical Workers Local 125 agreements, the Company contributes a stated amount per compensable hour plus 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 of approximately $16 million and $15 million during the years ended December 31, 2011 and 2010.

NOTE 11: INCOME TAXES

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

	Years Ended December 31, 2011	2010
Current:		
Federal	$ 2	$ (20)
State and local	—	—
	2	(20)
Deferred:		
Federal	43	60
State and local	13	13
	56	73
Investment tax credit adjustments	—	—
Income tax expense	$ 58	$ 53

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, 2011	2010
Federal statutory tax rate	35.0%	35.0%
Federal tax credits	(12.7)	(10.2)
State and local taxes, net of federal tax benefit	2.6	4.3
Flow through depreciation and cost basis differences	2.1	0.1
Investment tax credit amortization	—	—
Other	1.3	0.4
Effective tax rate	28.3%	29.6%

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

	As of December 31, 2011	As of December 31, 2010
Deferred income tax assets:		
Price risk management	$ 153	$ 73
Employee benefits	136	110
Tax credits, net of valuation allowance	56	—
Regulatory liabilities	14	99
Depreciation and amortization	18	54
Tax loss carryforwards	1	—
Other	10	72
Total deferred income tax assets	388	408
Deferred income tax liabilities:		
Depreciation and amortization	590	576
Regulatory assets	274	109
Price risk management	8	75
Employee benefits	1	86
Other	11	11
Total deferred income tax liabilities	884	857
Deferred income tax liability, net	$ (496)	$ (449)

As of December 31, 2011, PGE had no federal loss carryforwards and state loss carryforwards of less than $1 million, which will expire at various dates from 2016 through 2031. In addition, PGE has federal and state tax credit carryforwards of $42 million and $14 million, respectively, which will expire at various dates from 2012 through 2031.

PGE believes that it is more likely than not that its deferred income tax assets as of December 31, 2011 will be realized; accordingly, no valuation allowance has been recorded. As of December 31, 2010, PGE believed the benefit from state credit carryforwards expiring in 2011 would not be realized and, in recognition of this risk, the Company recorded a valuation allowance of $2 million on the deferred tax assets relating to these state credit carryforwards. During 2011, these state credit carryforwards expired unused. The net change in the valuation allowance for the years ended December 31, 2011 and 2010 were decreases of $2 million and $1 million, respectively.

As of December 31, 2010, the amount of the Company’s unrecognized tax benefit was $2 million, including interest, resulting from a gross increase in a position taken in a prior period. During the year ended December 31, 2010, the Company recognized $1 million in interest and no penalties. During the first quarter of 2011, the unrecognized tax benefit of $2 million was recognized as a result of filing for a federal tax accounting method change. As of December 31, 2011, PGE has no unrecognized tax benefits.

PGE files income tax returns in the U.S. federal jurisdiction, the states of Oregon and Montana, and certain local jurisdictions. The Internal Revenue Service (IRS) performed an examination of PGE’s income tax returns for 2007 and 2008 during 2010. This audit closed in the first quarter of 2011, with no material findings. In addition, the IRS commenced examination of the 2006, 2009, and 2010 income tax returns in the fourth quarter of 2011. The Company is not currently under examination by state or local tax authorities.

NOTE 12: STOCK PURCHASE PLANS

Employee Stock Purchase Plan

PGE has an employee stock purchase plan (ESPP), under which a total of 625,000 shares of the Company's common stock may be issued. The ESPP permits all eligible employees to purchase shares of PGE common stock through regular payroll deductions, which are limited to 10% of base pay. Each year, employees may purchase up to a maximum of $25,000 in common stock (based on fair value on the purchase date) or 1,500 shares, whichever is less. 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, 2011, there were 507,594 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, 2011, there were 2,496,842 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 (Restricted Stock Units) and performance-based vesting conditions (Performance Stock Units) 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 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 3,931,204 shares remain available for future issuance as of December 31, 2011.

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 Stock Units vest if performance goals are met at the end of a three-year performance period; such goals include return on equity and regulated asset base growth measures. Vesting of Performance 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 and Performance 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 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 and Performance Stock Unit activity is summarized in the following table:

	Units	Weighted Average Grant Date Fair Value
Outstanding as of December 31, 2009	422,263	$ 19.82
Granted	191,469	19.18
Forfeited	(45,081)	23.45
Vested	(103,223)	25.78
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

The number of vested Restricted and Performance Stock Units presented above exceed the number of shares issued for the vesting of restricted and performance stock units on the statements of equity because, upon vesting, the Company withholds a portion of the vested shares for the payment of income taxes on behalf of the employees. The total value of Restricted and Performance Stock Units vested during the years ended December 31, 2011 and 2010 was $1 million and $3 million, respectively. The weighted average fair value is measured based on the closing price of PGE common stock on the date of grant. For the years ended December 31, 2011 and 2010, PGE recorded $4 million and $2 million, respectively, of stock-based compensation expense, which is included in Administrative and general expense 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 less than $1 million in 2011 and 2010, which is not included in Administrative and general expenses in the statements of income.

As of December 31, 2011, unrecognized stock-based compensation expense was $4 million, of which approximately $3 million and $1 million is expected to be expensed in 2012 and 2013, respectively. Stock-based compensation expense was calculated assuming the attainment of performance goals that would allow the vesting of 121.8% and 117.9% of awarded Performance Stock Units for 2011 and 2010, respectively, with an estimated 6% forfeiture rate. No stock-based compensation costs have been capitalized and the plan had no material impact on cash flows for the years ended December 31, 2011 and 2010.

NOTE 14: COMMITMENTS AND GUARANTEES

Commitments

As of December 31, 2011, PGE's future minimum payments pursuant to purchase obligations for the following five years and thereafter are as follows (in millions):

	Payments Due						
	2012	2013	2014	2015	2016	Thereafter	Total
Capital and other purchase commitments	$ 58	$ 18	$ 10	$ 10	$ 6	$ 73	$ 175
Purchased power and fuel:							
Electricity purchases	129	77	76	76	57	381	796
Capacity contracts	21	21	21	20	19	—	102
Public Utility Districts	7	8	8	8	7	30	68
Natural gas	49	22	22	20	12	11	136
Coal and transportation	25	19	9	—	—	—	53
Operating leases	9	10	9	10	10	196	244
Total	$ 298	$ 175	$ 155	$ 144	$ 111	$ 691	$ 1,574

Capital and other purchase commitments—Certain commitments have been made for capital and other purchases for 2012 and beyond. Such commitments include those related to hydro licenses, upgrades to production, distribution and transmission facilities, decommissioning activities, information systems, and system maintenance work. 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 2036, and power capacity contracts through 2016. As of December 31, 2011, PGE has power sale contracts with counterparties of approximately $13 million in 2012.

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, 2011	PGE Share		Contract Expiration	PGE Cost, including Debt Service	
		Output	Capacity (in MW)		2011	2010
Priest Rapids and Wanapum	$ 917	8.8 %	176	2052	$ 14	$ 10
Wells	259	19.4	159	2018	10	7
Portland Hydro	11	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 and Beaver generating plants.

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 2014.

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 above 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 PGE's Beaver and Port Westward generating plants operate, which expires in 2096. Rent expense was $9 million in 2011 and in 2010.

The future minimum operating lease payments presented is net of sublease income of: $3 million in 2012; $2 million in 2013, 2014, and 2015; and $1 million in 2016. Sublease income was $3 million in 2011 and 2010.

Guarantees

PGE entered into a sale transaction in 1985 in which it sold an undivided 15% interest in Boardman and a 10.714% undivided interest in the Pacific Northwest Intertie (Intertie) transmission line (jointly the Boardman Assets) to an unrelated third party (Purchaser). The Purchaser leased the Boardman Assets to a lessee (Lessee) unrelated to PGE or the Purchaser. Concurrently, PGE assigned to the Lessee certain agreements for the sale of power and transmission services from Boardman and the Intertie (P&T Agreements) to a regulated electric utility (Utility) unrelated to PGE, the Purchaser, or the Lessee. The P&T Agreements expire on December 31, 2013. The payments by the Utility under the P&T Agreements exceed the payments to be made by the Lessee to the Purchaser under the lease. In exchange for PGE undertaking certain obligations of the Lessee under the lease, the Lessee reassigned to PGE certain rights, including the excess payments, under the P&T Agreements. However, in the event that the Utility defaults on the payments it owes under the P&T Agreements, PGE may be required to pay the damages owed by the Lessee to the Purchaser under the lease. Assuming no recovery from the Utility and no reduction in damages from mitigating sales or leases related to the Boardman Assets and P&T Agreements, the maximum amount that would be owed by PGE in 2012 is approximately $74 million. Management believes that circumstances that could result in such amount, or any lesser amount, being owed by the Company are remote.

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, 2011, management believes the likelihood is remote that PGE would be required to perform under such indemnification provisions or otherwise incur any significant losses with respect to such indemnities. The Company has not recorded any liability on the balance sheets with respect to these indemnities.

NOTE 15: JOINTLY-OWNED PLANT

PGE has interests in three jointly-owned generating facilities. Under the joint operating agreements, each participating owner is responsible for financing its share of construction, operating and leasing costs. PGE's proportionate share of direct operating and maintenance expenses of the facilities is included in the corresponding operating and maintenance expense categories in the statements of income.

As of December 31, 2011, 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	65.00%	1980	$ 467	$ 292	$ 2
Colstrip	20.00	1986	507	326	2
Pelton/Round Butte	66.67	1958 / 1964	206	46	11
Total			$ 1,180	$ 664	$ 15

* Excludes asset retirement obligations 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.

Loss contingencies are accrued and disclosed 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 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 return on, its Trojan costs in a general rate case filing with the OPUC. The OPUC issued a general rate order that granted the Company recovery of, and a 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 PGE 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 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 that required PGE to refund $15.4 million, plus interest at 9.6% from September 30, 2000, to customers who received service from PGE during the period 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 have separately appealed the 2008 Order to the Oregon Court of Appeals. Oral arguments were made on February 3, 2012 and a decision by the Oregon Court of Appeals remains pending.

Class Actions. In a separate legal proceeding, two 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 of $260 million, plus interest, as a result of PGE's inclusion, in prices charged to customers, of a return on its investment of 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 it can offer to PGE customers, through price reductions or refunds, for any amount of return on the Trojan investment PGE collected in prices for the period from April 1, 1995 through October 1, 2000.

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.

Because the above matters involve unsettled legal theories and have a broad range of potential outcomes, management cannot estimate a range of potential loss. Management believes, however, that these matters will not have a material impact on the financial condition of the Company, but may have a material impact on the results of operations and cash flows in future reporting periods.

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 its decision, concluding that the FERC failed to adequately explain how it considered or examined new evidence showing intentional market manipulation in California and its 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. 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. 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, contesting, among other things, the applicable refund period reflected in the Order, the use of the *Mobile-Sierra* standard, any restraints in the Order on the type of evidence that could be introduced in the hearing, and the lack of market-wide remedy. The rehearing requests remain pending.

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. The settlement proceedings are ongoing.

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.

Management cannot predict whether the FERC will order refunds in the Pacific Northwest Refund proceeding, which contracts would be subject to refunds, or how such refunds, if any, would be calculated. Accordingly, management cannot estimate a range of potential loss. Management believes, however, that the outcome will not have a material impact on the financial condition of the Company, but may have a material impact on PGE's results of operations and cash flows in future reporting periods.

EPA Investigation of Portland Harbor

A 1997 investigation by the EPA of a segment of the Willamette River known as the 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 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.

The Portland Harbor site is currently undergoing a remedial investigation and feasibility study (RI/FS) pursuant to an Administrative Order on Consent (AOC) between the EPA and several PRPs, not including PGE. In the AOC, the EPA determined that the RI/FS would focus on a segment of the river approximately 5.7 miles in length.

In January 2008, the EPA requested information from various parties, including PGE, concerning properties in or near the 5.7 mile segment of the river being examined in the RI/FS, as well as several miles beyond. Subsequently, the EPA has listed additional PRPs, which now number over one hundred.

The EPA will determine the boundaries of the site at the conclusion of the RI/FS in a Record of Decision in which it will document its findings and select a preferred cleanup alternative. The EPA is not expected to issue the Record of Decision until 2014.

Sufficient information is currently not available to determine the total cost of any required investigation or remediation of the Portland Harbor site or the liability of PRPs, including PGE. Accordingly, management cannot estimate a range of potential loss. Management believes, however, that the outcome will not have a material impact on the financial condition of the Company, but may have a material impact on PGE's results of operations and cash flows in future reporting periods.

EPA Investigation of Harbor Oil

Harbor Oil, Inc. operated an oil reprocessing business on a site located in north Portland (Harbor Oil), until about 1999. Subsequently, other companies have continued to conduct operations on the site. Until 2003, PGE contracted with the operators of the site to provide used oil from the Company's power plants and electrical distribution system to the operators for use in their reprocessing business. Other entities continue to utilize Harbor Oil for the reprocessing of used oil and other lubricants.

In 1974 and 1979, major oil spills occurred at the Harbor Oil site. Elevated levels of contaminants, including metals, pesticides, and polychlorinated biphenyls, have been detected at the site. In 2003, the EPA included the Harbor Oil site on the National Priority List as a federal Superfund site.

PGE received a Notice from the EPA in 2005, in which the Company was named as one of fourteen PRPs with respect to Harbor Oil. In 2007, an AOC was signed by the EPA and six other parties, including PGE, to implement an RI/FS at Harbor Oil. In 2011, the final draft of the remedial investigation report was submitted to the EPA, which has yet to issue a response.

Sufficient information is currently not available to determine the total cost of investigation and remediation of Harbor Oil or the liability of the PRPs, including PGE. Accordingly, management cannot estimate a range of potential loss. Management believes, however, that the outcome of this matter will not have a material impact on the financial condition of the Company, but may have a material impact on PGE's results of operations and cash flows in future reporting periods.

Revenue Bonds

In 2008, PGE repurchased $5.8 million of Pollution Control Revenue Bonds Series 1996 (Bonds) issued through the Port of Morrow. In connection with the repurchase, PGE paid the $5.8 million repurchase price to Lehman Brothers Inc. (Lehman) as remarketing agent for the Bonds, who in turn paid off the beneficial owner of the Bonds. As a result of the payment, PGE became the beneficial owner of the Bonds and requested that Lehman safe-keep the Bonds in Lehman's Depository Trust Company participant account until such time as the Bonds could be remarketed. After repurchase of the Bonds, PGE removed the liability for the Bonds from its financial statements.

In September 2008, Lehman filed for protection under Chapter 11 of the U.S. Bankruptcy Code. PGE subsequently filed a claim for return of the Bonds from Lehman. In November 2009, the trustee appointed to liquidate the assets of Lehman (Trustee) allowed PGE's claim as a net equity claim for securities. At the time, PGE believed it would receive back the entire amount of the Bonds at some point during the bankruptcy proceedings.

It is not certain that the Company will receive the full amount of the Bonds but could, along with other claimants, potentially receive a pro-rata share of certain assets. The timing and extent of distributions on claims are subject to the ultimate disposition of numerous claims in the proceedings and certain major contingencies which the Trustee must resolve. PGE cannot currently estimate how much of the value of the Bonds will ultimately be returned to the Company or the timing of the distribution from Lehman. Management does not expect the outcome of this matter to have a material impact on the Company's financial condition, but it may have a material impact on PGE's results of operations and cash flows in a future interim reporting period.

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 its business, which may result in adverse judgments against the Company. Although management currently believes that resolution of such matters will not have a material effect on its financial position, results of operations, or cash flows, these matters are subject to inherent uncertainties, and management's view of these matters may change in the future.

Name of Respondent 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 2011/Q4

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				(5,642,162)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				192,128
3	Preceding Quarter/Year to Date Changes in Fair Value				42,383
4	Total (lines 2 and 3)				234,511
5	Balance of Account 219 at End of Preceding Quarter/Year				(5,407,651)
6	Balance of Account 219 at Beginning of Current Year				(5,407,651)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				(738,690)
8	Current Quarter/Year to Date Changes in Fair Value				68,160
9	Total (lines 7 and 8)				(670,530)
10	Balance of Account 219 at End of Current Quarter/Year				(6,078,181)

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	109,735		(5,532,427)		
2	(42,383)		149,745		
3			42,383		
4	(42,383)		192,128	125,243,947	125,436,075
5	67,352		(5,340,299)		
6	67,352		(5,340,299)		
7	(68,160)		(806,850)		
8			68,160		
9	(68,160)		(738,690)	146,844,382	146,105,692
10	(808)		(6,078,989)		

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

Comprised of the net amount of the actuarial valuation of $(272,602) of non-qualified benefit plans net of taxes $80,474.

Schedule Page: 122(a)(b)   Line No.: 3   Column: e

PGE records a regulatory asset or regulatory liability pursuant to ASC 980 to offset the effects of unrealized gains and losses from the changes in the fair value of the Price Risk Management Assets and Liabilities designated as cash flow hedges. Consists of ASC 815 Unrealized Market-to-Market Gain of $(70,055) on natural gas forward and swap contracts and Deferred Taxes of $27,672.

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

Comprised of the net amount of the actuarial valuation of $1,250,966 of non-qualified benefit plans net of taxes $(512,276).

Schedule Page: 122(a)(b)   Line No.: 8   Column: e

PGE records a regulatory asset or regulatory liability pursuant to ASC 980 to offset the effects of unrealized gains and losses from the changes in the fair value of the Price Risk Management Assets and Liabilities designated as cash flow hedges. Consists of ASC 815 Unrealized Market-to-Market Loss of $(112,662) on natural gas forward and swap contracts and Deferred Taxes of $44,502.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

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

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

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	6,577,489,940	6,577,489,940
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	6,577,489,940	6,577,489,940
9	Leased to Others		
10	Held for Future Use	12,995,357	12,995,357
11	Construction Work in Progress	119,814,163	119,814,163
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	6,710,299,460	6,710,299,460
14	Accum Prov for Depr, Amort, & Depl	3,067,218,653	3,067,218,653
15	Net Utility Plant (13 less 14)	3,643,080,807	3,643,080,807
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	2,914,574,306	2,914,574,306
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	152,644,347	152,644,347
22	Total In Service (18 thru 21)	3,067,218,653	3,067,218,653
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)	3,067,218,653	3,067,218,653

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
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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 2011/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
			2
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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 2011/Q4

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

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents	140,616,873	125,361
4	(303) Miscellaneous Intangible Plant	145,228,079	45,508,772
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	285,844,952	45,634,133
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	4,126,752	34,009
9	(311) Structures and Improvements	215,828,260	215,848
10	(312) Boiler Plant Equipment	414,623,262	28,740,438
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	158,508,338	8,777,255
13	(315) Accessory Electric Equipment	46,304,824	848,650
14	(316) Misc. Power Plant Equipment	12,126,954	37,890
15	(317) Asset Retirement Costs for Steam Production	5,070,340	19,833,457
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	856,588,730	58,487,547
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	6,047,626	
28	(331) Structures and Improvements	36,113,942	1,917,060
29	(332) Reservoirs, Dams, and Waterways	227,658,370	5,826,983
30	(333) Water Wheels, Turbines, and Generators	45,857,396	972,991
31	(334) Accessory Electric Equipment	14,037,704	2,023,607
32	(335) Misc. Power PLant Equipment	1,820,891	30,470
33	(336) Roads, Railroads, and Bridges	9,273,317	138,921
34	(337) Asset Retirement Costs for Hydraulic Production	4,276	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	340,813,522	10,910,032
36	D. Other Production Plant		
37	(340) Land and Land Rights	48,946	
38	(341) Structures and Improvements	113,939,824	613,533
39	(342) Fuel Holders, Products, and Accessories	115,155,698	1,734,534
40	(343) Prime Movers		
41	(344) Generators	1,238,789,397	41,753,459
42	(345) Accessory Electric Equipment	61,742,084	769,510
43	(346) Misc. Power Plant Equipment	8,906,174	219,351
44	(347) Asset Retirement Costs for Other Production	2,213,948	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	1,540,796,071	45,090,387
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	2,738,198,323	114,487,966

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	11,126,862	
49	(352) Structures and Improvements	15,851,931	532,900
50	(353) Station Equipment	208,228,244	10,933,852
51	(354) Towers and Fixtures	46,806,048	
52	(355) Poles and Fixtures	17,484,371	1,985,771
53	(356) Overhead Conductors and Devices	72,401,937	7,481,838
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	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	372,238,764	20,934,361
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	13,654,237	21,068
61	(361) Structures and Improvements	33,710,996	2,237,316
62	(362) Station Equipment	332,220,097	26,037,867
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	295,830,321	13,505,931
65	(365) Overhead Conductors and Devices	479,665,378	34,300,688
66	(366) Underground Conduit	15,739,937	-52,743
67	(367) Underground Conductors and Devices	584,288,493	22,899,684
68	(368) Line Transformers	278,603,506	15,889,602
69	(369) Services	360,040,232	7,753,820
70	(370) Meters	119,670,404	3,584,653
71	(371) Installations on Customer Premises	376,133	
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	55,576,187	1,678,107
74	(374) Asset Retirement Costs for Distribution Plant	460,131	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	2,569,836,052	127,855,993
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	4,873,150	1,221,028
87	(390) Structures and Improvements	60,156,016	7,144,716
88	(391) Office Furniture and Equipment	56,939,198	11,202,157
89	(392) Transportation Equipment	40,569,901	1,339,483
90	(393) Stores Equipment	2,341,426	242,075
91	(394) Tools, Shop and Garage Equipment	10,920,355	519,839
92	(395) Laboratory Equipment	12,608,072	560,746
93	(396) Power Operated Equipment	42,430,473	2,774,009
94	(397) Communication Equipment	62,963,946	8,886,845
95	(398) Miscellaneous Equipment	137,680	1,445
96	SUBTOTAL (Enter Total of lines 86 thru 95)	293,940,217	33,892,343
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant	64,488	
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	294,004,705	33,892,343
100	TOTAL (Accounts 101 and 106)	6,260,122,796	342,804,796
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	6,260,122,796	342,804,796

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
		-104,334	140,637,900		3
			190,736,851		4
		-104,334	331,374,751		5
					6
					7
			4,160,761		8
29,203			216,014,905		9
379,928			442,983,772		10
					11
1,274,514			166,011,079		12
13,768			47,139,706		13
16,192			12,148,652		14
			24,903,797		15
1,713,605			913,362,672		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			6,047,626		27
1,974		104,334	38,133,362		28
26,001			233,459,352		29
713			46,829,674		30
50,539		19,510	16,030,282		31
			1,851,361		32
			9,412,238		33
			4,276		34
79,227		123,844	351,768,171		35
					36
			48,946		37
9,387			114,543,970		38
1,655,993			115,234,239		39
					40
511,119			1,280,031,737		41
2,156			62,509,438		42
24,234			9,101,291		43
			2,213,948		44
2,202,889			1,583,683,569		45
3,995,721		123,844	2,848,814,412		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 2011/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
6,753			11,120,109		48
19,067			16,365,764		49
137,021			219,025,075		50
			46,806,048		51
651,742			18,818,400		52
			79,883,775		53
					54
					55
			286,332		56
			53,039		57
814,583			392,358,542		58
					59
		6,223	13,681,528		60
79,330			35,868,982		61
2,714,964		-16,889	355,526,111		62
					63
1,284,392			308,051,860		64
878,392			513,087,674		65
75,857			15,611,337		66
433,398			606,754,779		67
831,925		-2,621	293,658,562		68
135,843			367,658,209		69
306,353			122,948,704		70
			376,133		71
					72
227,763			57,026,531		73
			460,131		74
6,968,217		-13,287	2,690,710,541		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
2,471			6,091,707		86
23,884			67,276,848		87
7,311,583			60,829,772		88
1,148,892			40,760,492		89
80,384			2,503,117		90
802,739			10,637,455		91
2,654,358			10,514,460		92
1,390,272			43,814,210		93
243,258			71,607,533		94
7,513			131,612		95
13,665,354			314,167,206		96
					97
			64,488		98
13,665,354			314,231,694		99
25,443,875		6,223	6,577,489,940		100
					101
					102
					103
25,443,875		6,223	6,577,489,940		104

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 2011/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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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 2011/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	Various	543,591
3	Marquam, Multnomah County, OR	2007	Various	3,112,750
4	Evergreen, Washington County, OR	2008	Various	2,609,767
5	Horizon, Washington County, OR	2007	Various	1,783,648
6	Teufel, Washington County, OR	2007	Various	649,143
7	Scholls Ferry, Washington County, OR	2009	Various	1,774,012
8	Shute Road, Washington County, OR	2009	Various	1,721,229
9	Highway 26 Easements, Washington County, OR	2009	Various	278,500
10	Evergreen Easement, Washington County, OR	2009	Various	334,928
11	Other Land and Land Rights (7 in Number)	Various	Various	187,789
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
23				
24				
25				
26				
27				
28				
29				
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36				
37				
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42				
43				
44				
45				
46				
47	Total			12,995,357

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 2011/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	Cascade Crossing Transmission Project	20,000,010
2	Baldock Solar Project	8,607,707
3	Rivermill - Fish Passage Improvements	8,012,813
4	Sunset Substation - Site Expansion For Intel	7,723,775
5	Work Management - Software Purchase And Implementation	6,409,859
6	Advanced Metering Infrustructure	5,441,516
7	Pelton/Round Butte - Fish Passage Improvements	4,965,086
8	Keeler (BPA) To Horizon Substation - 230-Kv Transmission Line	4,903,800
9	IT Cyber Security Project	4,512,594
10	Mobile Scheduling - Software Purchase And Implementation	3,591,864
11	Round Butte - Rewind Generator Unit #1	2,624,713
12	North Fork - Fish Passage Improvements	2,498,473
13	Dispatchable Generation	2,398,214
14	Faraday - Construct New Office Building	1,931,293
15	Construct New Transmission Substation - Horizon	1,847,543
16	Colstrip Capital Additions	1,832,117
17	Portland River District - Install Vaults And Conduit	1,765,565
18	Enterprise Asset Management - Software Purchase And Implementation	1,634,934
19	Pelton/Round Butte - Relicensing	1,614,684
20	Information Technology work Management - Software Purchase And Implementation	1,092,352
21	Overhead And Underground Distribution Line Construction	1,041,726
22	Biglow Canyon - Install Phase 1 Condition Monitoring System	935,604
23	Pelton/Round Butte - Day Use Area Site Improvemenets	932,432
24	Beaver - Purchase Spare Combustion Turbine	747,547
25	North Portland Voltage Conversion	735,550
26	Power Scheduling Accounting System - Software Replacement	733,881
27	Voice System Replacement Project	729,955
28	Communications Equipment - Purchase And Install	694,786
29	Document Composition - Software Replacement	641,287
30	Customer Information System - Software Performance Upgrade	640,520
31	Rivermill - Rewind Unit #5 Generator	635,954
32	Health And Welfare System - Peoplesoft Software Module	623,327
33	World Trade Center Upgrades	619,098
34	Oak Grove - Improve Clackamas River Aquatics	607,362
35	Faraday - Fish Passage Improvements	556,738
36	Substation Upgrades - Replace Obsolete Relays	544,771
37	Purchase Spare 28-MVA Transformer	544,082
38	Pelton/Round Butte - Shoreline Erosion Controls	506,274
39	Substation Upgrades - Install SCADA Communication Systems	471,937
40	Communication System Improvements - Install Fiber Optic Cables	419,630
41	Flex Rate Pricing Plan - Software Developement	406,536
42	PGE Online Customer Service - Stop Service Automation	342,313
43	TOTAL	119,814,163

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	Avery Facility - Site Improvements	327,807
2	Customer Quality And Reliability - Substation Control Improvements	322,159
3	Substation Safety Upgrades - Arc Flash Mitigation	322,147
4	Glencullen Substation - Replace Load Tap Changer	305,437
5	Clackamas River Recreation Area Improvements	300,524
6	Clackamas River Habitat Improvements	291,956
7	Construct New Distribution Substation - Cornell	282,407
8	Boardman - Install Water Recovery System	268,916
9	Construct New Distribution Substation - Scholls Ferry	263,179
10	Wallace Substation - Add Site Capacity	251,273
11	Sherwood To Pearl Substation (BPA) - Fiber Optic Cable Installation	243,855
12	Rivermill - Replace Generator Protection Relays	235,881
13	Pelton/Round Butte - Mitigation Fund	234,155
14	Portland Service Center Roof Replacement	225,239
15	Substation Upgrades - Station Control Relay Replacement	210,850
16	Sherwood Substation - Construct New 115-Kv Feeder	207,041
17	Build Facility At Carver Substation	202,745
18	Financial Forecasting Module - Purchase And Implementation	202,464
19	Rivergate Substation - Replace Digital Fault Recorder	178,278
20	Clackamas River Licensing - Develop Compliance Plan	174,956
21	Clackamas Lower River Gravel Augmentation	143,483
22	St. Mary's East Substation - Replace Motor Operated Disconnect Switches	138,886
23	Net Metering Automation Project	133,854
24	Server Infrastructure Vintage Replacement	131,207
25	Boardman - Install Coal Chute Detectors	128,155
26	Pelton - Replace Transformer RR-4	122,903
27	North Fork - Upgrade Station Service	111,912
28	Beaver To Allston Substation (BPA) 230-Kv Transmission Line	110,000
29	Coyote Springs - Replace Auxiliary Boiler Meter	108,092
30	Boardman - Fire Protection And Detection System	107,474
31	Banks Substation - Add Circuit Breakers	107,345
32	North Fork - Relicensing	105,818
33	Work Orders < 100,000	5,793,543
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	119,814,163

Schedule Page: 216 Line No.: 7 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 Northwestern Energy LLC, PP&L Montana, LLC, Puget Sound Energy, Inc., Pacific Corp, and Avista Corporation. Respondent's 20% share of the jointly owned costs is reported.

Schedule Page: 216 Line No.: 19 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.: 23 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.: 38 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: 216.1 Line No.: 8 Column: a

Jointly owned with Idaho Power Company, Power Resources Cooperative, and BA Leasing BSC, LLC. Respondent's 65% share of the jointly owned costs is reported.

Schedule Page: 216.1 Line No.: 13 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: 216.1 Line No.: 25 Column: a

Jointly owned with Idaho Power Company, Power Resources Cooperative, and BA Leasing BSC, LLC. Respondent's 65% share of the jointly owned costs is reported.

Schedule Page: 216.1 Line No.: 26 Column: a

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

Schedule Page: 216.1 Line No.: 30 Column: a

Jointly owned with Idaho Power Company, Power Resources Cooperative, and BA Leasing BSC, LLC. Respondent's 65% share of the jointly owned costs is reported.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	2,725,051,756	2,725,051,756		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	211,052,942	211,052,942		
4	(403.1) Depreciation Expense for Asset Retirement Costs	1,919,928	1,919,928		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	3,969,636	3,969,636		
7	Other Clearing Accounts	267,889	267,889		
8	Other Accounts (Specify, details in footnote):				
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	217,210,395	217,210,395		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	25,434,650	25,434,650		
13	Cost of Removal	4,530,164	4,530,164		
14	Salvage (Credit)	2,241,187	2,241,187		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	27,723,627	27,723,627		
16	Other Debit or Cr. Items (Describe, details in footnote):	35,782	35,782		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	2,914,574,306	2,914,574,306		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	611,414,736	611,414,736		
21	Nuclear Production				
22	Hydraulic Production-Conventional	136,324,222	136,324,222		
23	Hydraulic Production-Pumped Storage				
24	Other Production	378,583,488	378,583,488		
25	Transmission	169,731,883	169,731,883		
26	Distribution	1,479,972,471	1,479,972,471		
27	Regional Transmission and Market Operation				
28	General	138,547,506	138,547,506		
29	TOTAL (Enter Total of lines 20 thru 28)	2,914,574,306	2,914,574,306		

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

$35,782 Adjustment for purchase of co-owned asset and reclass from Depreciation to Intangible Reserve

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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			73,989
4	Sub - TOTAL			74,989
5				
6	Salmon Springs Hospitality Group			
7	Common Stock	04/09/98		10,000
8	Equity in Earnings			-364,609
9	Sub - TOTAL			-354,609
10				
11	SunWay 1, LLC			
12	Paid in Capital	5/29/08		156,273
13	Equity in Earnings			-109,975
14	Sub - TOTAL			46,298
15				
16	SunWay 2, LLC			
17	Paid in Capital	9/16/08		525,014
18	Equity in Earnings			-215,922
19	Sub - TOTAL			309,092
20				
21	SunWay 3, LLC			
22	Paid in Capital	10/19/09		2,415,395
23	Equity in Earnings			-395
24	Sub - TOTAL			2,415,000
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 2,892,279		TOTAL	2,490,770

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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
14,003		87,992		3
14,003		88,992		4
				5
				6
		10,000		7
387,947		23,338		8
387,947		33,338		9
				10
				11
		156,273		12
-3		-109,978		13
-3		46,295		14
				15
				16
		525,014		17
-8		-215,930		18
-8		309,084		19
				20
				21
		2,415,395		22
-20	-410	-825		23
-20	-410	2,414,570		24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
401,919	-410	2,892,279		42

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

Represents PGE's share of SunWay 1, LLC, a variable interest entity jointly owned by PGE (0.01% interest) and U.S. Bank (99.9% 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 12/31/2011 (100%)

In-Service Production cost: $1,097,814
Total installed capacity: 104 kW
Operations and Maintenance for 2011: $76,083

Schedule Page: 224 Line No.: 19 Column: g

Represents PGE's share of SunWay 2, LLC a variable interest entity jointly owend 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 facilites.

SunWay 2, LLC statistics at 12/31/2011 (100%)

In-service Production cost: $5,922,280
Total installed capacity: 1.1 MW
Operations and Maintenance for 2011: $360,170

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 pupose 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 12/31/2011 (100%)

In-service Production cost: $7,569,784
Total installed capacity: 2.4 MW
Operations and Maintenance for 2011: $496,504

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)	21,503,107	33,794,768	Generation
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	14,088,552	13,216,761	Distribution
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	14,866,105	17,595,441	Generation
8	Transmission Plant (Estimated)	103,952	48,017	Transmission
9	Distribution Plant (Estimated)	1,380,713	1,367,910	Distribution
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	347,155	434,061	Power Operations
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	30,786,477	32,662,190	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)	6,081	6,081	Customer Service
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	2,944,884	4,659,816	
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	55,240,549	71,122,855	

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 2011/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		2012	
		No. (b)	Amt. (c)	No. (d)	Amt. (e)
1	Balance-Beginning of Year	27,902.00	360,000	10,032.00	
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	9,598.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	18,304.00	360,000	10,032.00	
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	1,151.76		144.12	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	144.78			
40	Balance-End of Year	1,006.98		144.12	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2013		2014		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
10,029.00		10,033.00		170,523.00		228,519.00	360,000	1
								2
								3
								4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						9,598.00		18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
10,029.00		10,033.00		170,523.00		218,921.00	360,000	29
								30
								31
								32
								33
								34
								35
144.12		144.12		4,476.96		6,061.08		36
								37
								38
				144.78		289.56		39
144.12		144.12		4,332.18		5,771.52		40
								41
								42
								43
								44
								45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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		2012	
		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 2011/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.

2013		2014		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
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								32
								33
								34
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								39
								40
								41
								42
								43
								44
								45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

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

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21						
22	Abandoned Trojan Nuclear Plant					
23	Decommissioning Costs;	298,321,517	1,118,597	407	3,500,000	987,024
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	298,321,517	1,118,597		3,500,000	987,024

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	Coyote Springs NITS SIS	170	561.6	170	456
3	Trojan-Horizon Project - Fac	1,128	561.6	1,128	456
4	System Impact Study for TSR 745708	423	561.6	423	456
5	NI-19 162MW Beaver	426	561.6	426	456
6	NI-18 220MW PW#2	341	561.6	341	456
7	Other	2,052	561.6		
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	Martinsdale Wind Project	8,608	561.7	8,608	456
23	Boardman Facilities Study	13,658	561.7	13,658	456
24	Coyote Facility Study	5,205	561.7	5,205	456
25	Port Westward Unit 2	(334)	561.7	(334)	456
26	Carty Generating Station	32	561.7	32	456
27	Interconnection Study - Maupin	2,540	561.7	2,540	456
28	Rock Creek 09-035	82	561.7	82	456
29	Martinsdale - Facilities	6,230	561.7	6,230	456
30	Rock Creek Wind Energy Project	496	561.7	496	456
31	BP Wind Energy Inc - Application	1,327	561.7	1,327	456
32	Trojan-Horizon Project - Facility	171	561.7	171	456
33	First Wind LGIA	6,725	561.7	6,725	456
34	419MW - CCCT at Boardman	5,922	561.7	5,922	456
35	LGIP Facilities Study Request 09-3	(157)	561.7	(157)	456
36	BP Wind System Impact Study	554	561.7	554	456
37	Nook Wind Power #1 FEA	(136)	561.7	(136)	456
38	Nook Wind Power #2 FEA	385	561.7	385	456
39	10-037 LGIP SIS	139	561.7	139	456
40	LGIP Port Westward 2	973	561.7	973	456

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

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 11-039 Phillipi #1	927	561.7	927	456
23	LGIP Request #11-042	198	561.7	198	456
24	LGIP Request #11-042 FEA	1,083	561.7	1,083	456
25	LGIP #11-043 FEA	2,558	561.7	2,558	456
26	LGIP #11-041 FEA	716	561.7	716	456
27	LGIP Request 11-045 FEA	18,706	561.7	18,706	456
28	LGIP Request 11-046 FEA	10,052	561.7	10,052	456
29	Other	104,629	561.7		
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Schedule Page: 231   Line No.: 7   Column: b

Represents various study costs charged to FERC 561.6 but not assigned to specific studies.

Schedule Page: 231.1   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	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) / /	End of 2011/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	69,225,530	441,511	282	14,595,842	55,071,199
2	Previously Flowed to Customers	42,174,682	2,046,983	283	8,266,087	35,955,578
3	(Amort. period is based on the lives of the	110,634	2,743	190	113,377	
4	properties, approximately 25 years.)					
5						
6	Photovoltaic Volumetric Incentive Pilot	232,779	1,461,630			1,694,409
7	(per OPUC Order No. 10-198 dtd 05/28/2010)					
8						
9	Colstrip Common Facilities (28 year amort. ending	2,040,227		407.3	322,140	1,718,087
10	2017, FERC OCA-AD ltr dtd 05/23/1989)					
11						
12	Price Risk Management	360,503,694	223,567,951	Various	218,845,250	365,226,395
13						
14	Deferred Broker Settlement	23,567,016	17,369,555	555	29,849,417	11,087,154
15						
16	Intervenor Funding (original deferral per OPUC	1,024,240	80,401	407.3	920,591	184,050
17	Order No. 03-388 dtd 7/2/2003; current year					
18	reauthorization through various orders; 2011					
19	amortization per Advice 10-22A dtd 12/23/2010)					
20						
21	Senate Bill 408 Deferral - YR 2006	137,950	83,500	449.1/	221,450	
22	(per OPUC Order no. 10-129 dtd 4/06/2010,			182.3		
23	amortization period: 6/1/2010 - 5/31/2011)					
24						
25	Senate Bill 408 Deferral - YR 2007	250,226	921	449.1/	251,147	
26	(per OPUC Order no. 10-129 dtd 4/06/2010,			182.3		
27	amortization period: 6/1/2010 - 5/31/2011)					
28						
29	Senate Bill 408 Deferral - Local Residual 2007	372,332	182,940	449.1/229	393,469	161,803
30	Multnomah County Business Income Tax Balancing					
31						
32	Independent Evaluator Deferral	286,196	23,856			310,052
33	(per OPUC Order No. 08-010 dtd 1/14/2008)					
34						
35	Independent Evaluator Deferral (2011)		140,487			140,487
36	(per OPUC Order No. 11-154 dtd 05/10/2011)					
37						
38	Schedule 110 Energy Efficiency - Balancing Acct		938,799	407	925,790	13,009
39	(per Advice No. 07-25 dtd 05/20/2008)					
40						
41	Automated Demand Response Balancing		50,378			50,378
42	(per Advice 10-29 dtd 12/29/2010)					
43						
44	TOTAL	755,788,489	347,927,932		319,048,483	784,667,938

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 2011/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	Smart Meter Project Office Costs	1,283,030	106,947			1,389,977
2	(per OPUC Order No. 08-209 dtd 4/11/2008)					
3						
4	Generation Plant Maintenance Deferral	5,475,936		553	684,492	4,791,444
5	(per OPUC Order No. 08-601 dtd 12/29/2008					
6	amortization period: 1/1/2009 - 12/31/2018)					
7						
8	Stable Rate Revenue Balancing Acct	260,812	379,845			640,657
9	(per Advice No 06-13 dtd 6/22/2006)					
10						
11	Small Nonres Sch 123 SNA Deferral-2009	1,048,673	4,602	456/182.3	1,053,275	
12	(per Advice 10-28 dtd 12/21/2010;					
13	amortization period: 06/01/2010 - 05/31/2011)					
14						
15	Small Nonres Sch 123 SNA Deferral-2010	2,350,099	98,573	456	1,255,364	1,193,308
16	Residential Sch 123 SNA Deferral-2010	4,161,613	727,225	456	2,506,368	2,382,470
17	Residential Sch 123 SNA Deferral-2011		906,737			906,737
18	(per OPUC Order No. 09-162 dtd 05/06/2009;					
19	reauthorized OPUC Order No. 10-478 dtd					
20	12/17/2010, UE 215 Remaining Issues Stipulation)					
21						
22	Trojan Refund Deferral - Incremental Costs	2,812,091	221,147			3,033,238
23	(per OPUC Order No 09-133 dtd 4/14/2009)					
24						
25	SunWay Deferral	179,040	430	456/182.3	180,840	-1,370
26	(per OPUC Order No. 10-391 dtd 10/11/2010;					
27	amortization period: 01/01/2011 - 12/31/2011)					
28						
29	Residual Deferred Account	637,934	297,447			935,381
30	(per OPUC Order No. 10-279 dtd 07/23/2010)					
31						
32	City of Glendale Wholesale Sales	2,040,000		447	840,000	1,200,000
33	(FERC Docket No. ER10-1286-000)					
34						
35	Glass Insulator Deferral		554,590			554,590
36	(OPUC Order No. 10-478 dtd 12/17/2010;					
37	UE 215 First Revenue Requirement Stipulation)					
38						
39	Pension Funding	187,601,450	97,381,229	219	9,475,430	275,507,249
40	Postretirement Funding	25,135,206		219	5,828,731	19,306,475
41	(per SFAS No. 158 adopted 12/31/2006;					
42	OPUC Order No. 07-051 dtd 02/12/2007)					
43						
44	TOTAL	755,788,489	347,927,932		319,048,483	784,667,938

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	Direct Access Open Enrollment Deferral - 2008	467,424	10,640	447	464,740	13,324
2	(per Advice No. 10-22A dtd 12/28/2010					
3	amortization period: 1/1/2011 - 12/31/2011)					
4						
5	Direct Access Open Enrollment Deferral - 2009	108,345	164	447/182.3	108,509	
6	(per Advice No. 09-22 dtd 12/22/2009					
7	amortization period: 1/1/2010 - 12/31/2010)					
8						
9	ISFSI Pollution Control Tax Credit Deferral		274,000			274,000
10	(per OPUC Order No. 01-777 dtd 8/31/2001)					
11						
12	Boardman Decommissioning Balancing		214,909			214,909
13	(per Advice No. 11-07 dtd 05/27/11)					
14						
15	Biglow Canyon Phase 2 Deferral	4,537,955	56,947	456	4,684,160	-89,258
16	(per OPUC Order No. 09-398 dtd 10/05/2009 &					
17	OPUC Order No. 10-391 dtd 10/11/2010;					
18	amortization period: 01/01/2010 - 12/31/2011)					
19						
20	Biglow Canyon Phase 3 Deferral	17,763,375	300,845	456	17,262,014	802,206
21	(per OPUC Order No. 10-391 dtd 10/11/2010;					
22	amortization period: 01/01/2011 - 12/31/2012)					
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	755,788,489	347,927,932		319,048,483	784,667,938

Schedule Page: 232 Line No.: 12 Column: d
Amounts charged to Accounts 555, 547 and 219.

Schedule Page: 232 Line No.: 16 Column: c
Current year reauthorization approved through OPUC orders:
11-010, dated 01/10/2011, Intervenor Fund Grant
11-034, dated 01/26/2011, Intervenor Issue Fund Grant
11-175, dated 05/25/2011, Intervenor Issue Fund Grant
11-323, dated 08/18/2011, Intervenor Issue Fund Grant
11-417, dated 10/19/2011, Intervenor Issue Fund Grant
11-437, dated 11/09/2011, Intervenor Issue Fund Grant

Schedule Page: 232 Line No.: 21 Column: d
The residual balance remaining after the authorized amortization period was combined into the Residual Deferred Account pursuant to OPUC Order No. 10-279, dated 07/23/2010.

Schedule Page: 232 Line No.: 25 Column: d
The residual balance remaining after the authorized amortization period was combined into the Residual Deferred Account pursuant to OPUC Order No. 10-279, dated 07/23/2010.

Schedule Page: 232 Line No.: 29 Column: d
The residual balance of the local SB408 Multnomah County Business Income Tax deferral vintage year 2007 was combined with the vintage year 2011 balance in Account 229, Accumulated Provision for Rate Refunds.

Schedule Page: 232 Line No.: 35 Column: f
Deferral of costs associated with an Independent Evaluator retained to assist in the design, implementation, evaluation and reporting on Request for Proposals submitted during the integrated resource planning process.

Schedule Page: 232 Line No.: 38 Column: c
Reclassified debit balance from Regulatory Liability to Regulatory Asset.

Schedule Page: 232 Line No.: 41 Column: f
Balance represents the deferral of costs associated with the Automated Demand Response pilot program that allows for automatic load curtailment during critical events for participating non-residential customers.

Schedule Page: 232.1 Line No.: 11 Column: d
The residual balance remaining after the authorized amortization period was combined into the Residual Deferred Account pursuant to OPUC Order No. 10-279, dated 07/23/2010.

Schedule Page: 232.1 Line No.: 25 Column: d
The residual balances for SunWay 1 and SunWay 2 remaining after the authorized amortization period were combined into the Residual Deferred Account pursuant to OPUC Order No. 10-279, dated July 23, 2010.

Schedule Page: 232.1 Line No.: 29 Column: f
Balance represents the combined residual balances of deferred accounts past their authorized amortization period pursuant to OPUC Order No. 10-279, dated July 23, 2010.

Schedule Page: 232.1 Line No.: 35 Column: f
Balance represents the deferral of glass insulator costs for treatment as capitalized costs for amortization over the average useful life of transmission poles.

Schedule Page: 232.2 Line No.: 5 Column: d
The residual balance remaining after the authorized amortization period was combined into the Residual Deferred Account pursuant to OPUC Order No. 10-279, dated 07/23/2010.

Schedule Page: 232.2 Line No.: 9 Column: c
Reclassified debit balance from Regulatory Liability to Regulatory Asset.

Schedule Page: 232.2 Line No.: 12 Column: f
Balancing account to track the difference between actual collections from customers and the revenue requirement related to the increase in depreciation/amortization expense and the decommissioning costs due to the planned Boardman plant closure changing from the year 2040 to the year 2020.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	37,108	755,611	Various	265,347	527,372
3						
4	Net Trust Contributions	1,655,005	71,076,498	Various	69,698,118	3,033,385
5						
6	Pebble Springs AFDC &					
7	Tax Credit Sale -					
8	amort. over service lives					
9	of related property	259,989	2,580	421/425	36,536	226,033
10						
11	Deferred Wheeling Costs -					
12	amort. over 25 yrs through 2012	342,489		565	196,416	146,073
13						
14	Deferred Rent - WTC Tenant					
15	amort. through 2015	128,081	119,601	418	191,951	55,731
16						
17	Deferred Revolving Credit					
18	Agreement Fees					
19	amort. through 2016	1,134,562	1,849,437	431	1,395,105	1,588,894
20						
21	Dispatchable Generation					
22	various amort. periods beg in					
23	2000 and extending through 2017	6,333,644	3,081,627	903	1,387,482	8,027,789
24						
25	LID Receivable from WTC Tenants					
26	amort. over 20 yrs through 2030	113,795		418	5,989	107,806
27						
28	Colstrip - Lime Contract					
29	amort. over 4 yrs. 2011 - 2014	2,550,000		Various	700,000	1,850,000
30						
31	Coyote2 LLC	112,323	2,223,115	Various	2,260,752	74,686
32						
33						
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42						
43						
44						
45						
46						
47	Misc. Work in Progress	162,648				114,645
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	12,829,644				15,752,414

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	48,765,548	12,618,109
3	Regulatory Liabilities	98,602,479	14,338,937
4	Employee Benefits	109,531,442	135,056,855
5	Price Risk Management	72,737,813	153,152,250
6	Tax Credits & NOL's	55,789,647	56,757,746
7	Other	13,284,558	9,949,559
8	TOTAL Electric (Enter Total of lines 2 thru 7)	398,711,487	381,873,456
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)	9,231,989	5,774,814
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	407,943,476	387,648,270

Notes

	Balance at Beginning of Year	Balance at End of Year
Line 7 - Other		
Bad Debt Expense	$ 2,078,737	$ 2,206,951
Nuclear Decommissioning Trust	1,532,307	992,542
Miscellaneous Other	9,673,514	6,750,066
Total Line 7 - Other	$13,284,558	$ 9,949,560
Line 17 - Other - NonUtility		
Property Related	$ 5,622,778	$ 4,837,098
Software Costs	334,170	334,170
Miscellaneous	3,275,041	603,546
Total Line 17 - Other - NonUtility	$ 9,231,989	$ 5,774,814

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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				
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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 2011/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
75,362,956	828,591,553					2
						3
75,362,956	828,591,553					4
						5
						6
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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	50,570
12	SUBTOTAL Account 210	50,570
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	36,776
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	8,890,524
22		
23		
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27		
28		
29		
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31		
32		
33		
34		
35		
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39		
40	TOTAL	15,302,074

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

Represents the assumption of PGE's current tax liability by the Company's former parent company on taxable income related to the transfer of non-qualified plan liabilities to PGE from Portland General Holdings, recorded in 2005.

Schedule Page: 253 Line No.: 20 Column: b

PGE generated approximately $13 million of Oregon tax credits that, due to taxable income limitations, were not utilized by the Company's former parent company prior to the separation of the two companies on April 3, 2006. Prior to 2006, pursuant to a tax sharing agreement, PGE utilized these tax credits to reduce its tax payment obligations to its former parent; however, the former parent was unable to utilize these credits on its tax returns. PGE then utilized a portion of the tax credits to offset quarterly income tax payments due to the State of Oregon during periods subsequent to the separation, with no effect on income. In 2008 and 2009, the realization of such tax credits by PGE was reflected as an adjustment to equity, net of related federal tax effect.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

CAPITAL STOCK EXPENSE (Account 214)

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

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Stock	7,771,347
2		
3		
4	No Par Cumulative Preferred Stock - 7.75% Series	305,275
5		
6		
7		
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19		
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21		
22	TOTAL	8,076,622

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

The $41,901 increase from December 31, 2010 is due to expenses related to PGE's Dividend Reinvestment and Direct Stock Purchase Plans. Initial stock issuances under the plans, which were approved by the Company's Board of Directors on May 13, 2010, took place in April 2011.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACCOUNT 221 - Bonds:		
2	First Mortgage Bonds -		
3	5.6675% Series due 2012	100,000,000	12,248,703
4	9.31% Medium-Term Note Series Due 8/11/2021	20,000,000	176,577
5	5.625% Series VI Due 8/1/2013	50,000,000	406,662
6			325,000 D
7	6.75% Series VI Due 8/1/2023	50,000,000	519,234
8			437,500 D
9	6.875% Series VI Due 8/1/2033	50,000,000	519,257
10			437,500 D
11	6.26% Series Due 5/1/2031	100,000,000	723,856
12	6.31% Series Due 5/1/2036	175,000,000	1,270,565
13	5.80% Series Due 6/1/2039	170,000,000	1,460,968
14	5.81% Series Due 10/1/2037	130,000,000	1,109,574
15			517,518 D
16	5.80% Series Due 03/01/2018	75,000,000	282,501
17	4.45% Series Due 04/1/2013	50,000,000	340,444
18			625,100 D
19	6.50% Series Due 1/15/2014 - Order No. 08-106 01/28/2008	63,000,000	429,463
20	6.80% Series Due 1/15/2016 - Order No. 08-106 01/28/2008	67,000,000	456,731
21	6.10% Series Due 4/15/2019 - Order No. 09-089 03/16/2009	300,000,000	2,386,224
22			222,000 D
23	5.43% Series Due 5/3/2040 - Order No. 09-245 06/22/2009	150,000,000	1,034,284
24	3.46% Series Due 1/14/2015 - Order No. 09-405 10/08/2009	70,000,000	455,869
25	3.81% Series Due 6/15/2017 - Order No. 09-405 10/08/2009	58,000,000	375,096
26	Pollution Control Bonds (Guaranteed by Company) -		
27	Port of Morrow, OR Series 1998A 5% Due 5/1/2033	23,600,000	604,452
28	City of Forsyth, MT Series 1998A 5% Due 5/1/2033	97,800,000	2,615,167
29	Port of St. Helens, OR Series 1990A 5.25% Due 8/1/2014	9,600,000	386,344
30	SUBTOTAL ACCOUNT 221	1,809,000,000	30,366,589
31			
32	ACCOUNT 224 - OTHER LONG TERM DEBT		
33	TOTAL	1,809,119,785	30,366,589

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	City of Portland Improvement District Loan	119,785	
3	SUBTOTAL ACCOUNT 224	119,785	
4			
5			
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7			
8			
9			
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30			
31			
32			
33	TOTAL	1,809,119,785	30,366,589

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
10/28/2002	10/25/2012	10/28/2002	10/25/2012	100,000,000	5,667,474	3
08/12/1991	08/11/2021	08/12/1991	08/11/2021	20,000,000	1,861,969	4
08/01/2003	08/01/2013	08/01/2003	08/01/2013	50,000,000	2,812,500	5
						6
08/01/2003	08/01/2023	08/01/2003	08/01/2023	50,000,000	3,375,000	7
						8
08/01/2003	08/01/2033	08/01/2003	08/01/2033	50,000,000	3,437,524	9
						10
05/26/2006	05/01/2031	05/26/2006	05/01/2031	100,000,000	6,259,988	11
05/26/2006	05/01/2036	05/26/2006	05/01/2036	175,000,000	11,042,512	12
05/16/2007	06/01/2039	05/16/2007	06/01/2039	170,000,000	9,859,990	13
09/19/2007	10/01/2037	09/19/2007	10/01/2037	130,000,000	7,553,008	14
						15
12/12/2007	03/01/2018	12/12/2007	03/01/2018	75,000,000	4,350,000	16
04/15/2008	04/01/2013	04/15/2008	04/01/2013	50,000,000	2,231,174	17
						18
01/15/2009	01/15/2014	01/15/2009	01/15/2014		4,083,625	19
01/15/2009	01/15/2016	01/15/2009	01/15/2016	67,000,000	4,556,004	20
04/16/2009	04/15/2019	04/16/2009	04/15/2019	300,000,000	18,300,000	21
						22
11/30/2009	05/03/2040	11/30/2009	05/03/2040	150,000,000	8,145,000	23
01/15/2010	01/14/2015	01/15/2010	01/14/2015	70,000,000	2,421,997	24
06/15/2010	06/15/2017	06/15/2010	06/15/2017	58,000,000	2,215,050	25
						26
05/28/1998	05/01/2033	05/28/1998	05/01/2033	23,600,000	1,178,915	27
05/28/1998	05/01/2033	05/28/1998	05/01/2033	97,800,000	4,885,619	28
08/08/1990	08/01/2014	08/08/1990	08/01/2014		16,800	29
				1,736,400,000	104,254,149	30
						31
						32
				1,736,507,806	104,254,149	33

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
11/16/2009	11/16/2029			107,806		2
				107,806		3
						4
						5
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						32
				1,736,507,806	104,254,149	33

Schedule Page: 256 Line No.: 19 Column: e

The $63,000,000 6.50% Series First Mortgage Bonds Due 1/15/2014 were redeemed by PGE on December 28, 2011. The Company paid a premium of $7,279,650 at the time of redemption; unamortized debt issue costs were $173,913. Both of these amounts are being amortized over the remaining life of the original debt.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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)	146,844,382
2		
3		
4	Taxable Income Not Reported on Books	
5	Depreciation, Depletion & Amortization	16,314,282
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Depreciation, Depletion & Amortization	16,961,611
11	Price Risk Management and Mark-To-Market	7,322,701
12	Regulatory Debits	43,648,321
13	Total Other (See Footnote)	67,140,860
14	Income Recorded on Books Not Included in Return	
15	Depreciation, Depletion & Amortization	-7,684,839
16	Regulatory Credits	-4,525,736
17	Total Other (See Footnote)	-792,904
18		
19	Deductions on Return Not Charged Against Book Income	
20	Depreciation, Depletion & Amortization	-178,392,536
21	State & Local Tax Deduction	-365,683
22	Total Other (See Footnote)	-35,652,239
23		
24	Federal Tax Net Income (Loss) Before NOL	70,818,220
25	Federal NOL Carryforward	-15,021,112
26		
27	Federal Tax Net Income	55,797,108
28	Show Computation of Tax:	
29	Normal Federal Current Provision Benefit @35%	19,528,988
30	Federal Energy Tax Credit	-14,646,741
31	AMT Credit Carryforward	-4,882,247
32	Total Federal Income Tax - PGE	
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

Schedule Page: 261 Line No.: 13 Column: b

Unrealized Gain	1,550,018
Qualified NDT	559,109
Miscellaneous	1,739,011
Travel & Entertainment	400,000
Political Activity	890,033
Bad Debts	4,425,423
Federal Provision	44,493,755
State Provision	13,083,511
Total Other	67,140,860

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

Dividend Received Deduction	(300,000)
Miscellaneous	(492,904)
Total Other	(792,904)

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

Miscellaneous	(5,452,094)
Employee Benefits	(26,394,621)
Bad Debts	(3,805,524)
Total Other	(35,652,239)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1	Federal:					
2	FERC Resale/Coord	125,001		665,852	665,852	
3	Income Tax	3,123,361	21,604,924	1,808,003	-5,498,629	-1,177,079
4	Foreign Insurance Excise Tax					
5	FICA (Employer Share)	1,153,362		17,633,879	17,414,306	
6	Unemployment	39,533		125,692	161,096	
7	Power License	1,123,739		1,226,301	1,629,605	
8	Superfund Tax					
9	SUBTOTAL Federal	5,564,996	21,604,924	21,459,727	14,372,230	-1,177,079
10	State of Montana:					
11	Income Tax	7,718	379,869	134,864	-213,497	145,740
12	Elec. Energy Producers Tax	226,291		617,718	644,342	
13	Property Taxes	2,190,175		4,322,084	4,354,105	
14	SUBTOTAL Montana	2,424,184	379,869	5,074,666	4,784,950	145,740
15	State of Oregon:					
16	Corp Excise Tax	45,740	-100,000	100,000	100,000	-145,740
17	Property Taxes		18,524,646	39,410,473	41,474,311	
18	City Taxes and Licenses	3,438,624	208	40,552,606	40,355,392	
19	Public Utility Comm Fees			4,839,365	4,839,365	
20	Department of Energy		578,850	1,290,402	1,423,101	
21	Department of Enviro Quality	726,530		364,832	430,525	
22	Unemployment	148,594		1,977,464	2,074,899	
23	Water Power Fee		223,768	342,029	660,172	
24	Transportation Tax	82,930		1,482,853	1,260,174	
25	Workers Comp Assessment	43,499		178,456	159,675	
26	County & City Income Tax	122,644	-200	63,145	77,733	
27	SUBTOTAL Oregon	4,608,561	19,227,272	90,601,625	92,855,347	-145,740
28	State of Washington:					
29	Property Taxes	38,400		45,644	43,244	
30	Sales Tax					
31	SUBTOTAL Washington	38,400		45,644	43,244	
32	State of Wyoming:					
33	Sales Tax					
34	SUBTOTAL Wyoming					
35	State of California:					
36	Corporate franchise tax					
37	SUBTOTAL California					
38	Canada:					
39	Goods & Services Tax					
40	SUBTOTAL Canada					
41	TOTAL	12,636,141	41,212,065	117,181,662	112,055,771	-1,177,079

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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					665,852	2
-48,312	12,303,698	1,994,642			-186,639	3
						4
1,372,935		9,814,039			7,819,840	5
4,129		70,594			55,098	6
720,436	1				1,226,301	7
						8
2,174,189	12,303,699	11,879,275			9,580,452	9
						10
230,604	108,654	129,936			4,928	11
199,667		360,758			256,960	12
2,158,154		3,907,047			415,037	13
2,588,425	108,654	4,397,741			676,925	14
						15
		145,740			-45,740	16
	20,588,484	37,765,566			1,644,906	17
3,635,630		40,567,687			-15,081	18
					4,839,365	19
	711,549	1,342,211			-51,809	20
660,837					364,832	21
51,159		1,108,879			868,585	22
	541,911				342,029	23
305,609		1,451,173			31,680	24
62,280		127,593			50,863	25
108,256		82,244			-19,099	26
4,823,771	21,841,944	82,591,093			8,010,531	27
						28
40,800		45,644				29
						30
40,800		45,644				31
						32
						33
						34
						35
						36
						37
						38
						39
						40
9,627,185	34,254,297	98,913,753			18,267,908	41

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

Federal tax return examination interest adjustment

Schedule Page: 262 Line No.: 11 Column: f

Reclassification for various tax position adjustments

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

Reclassification for various tax position adjustments

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%	14,052			420	14,052	
6							
7							
8	TOTAL	14,052				14,052	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
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46							
47							
48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

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

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
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			37
			38
			39
			40
			41
			42
			43
			44
			45
			46
			47
			48

Schedule Page: 266 Line No.: 5 Column: f

Investment tax credit amortization to income ended in 2011.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	Miscellaneous credits				308	308
2						
3	Accelerated cost recovery system					
4	tax benefit sale - amort. over					
5	service lives of related					
6	property	259,990	421	33,956		226,034
7						
8	Tenant sub-lease security deposits	65,654	418	18,463	9,033	56,224
9						
10	Deferred premiums on power		555	789,910	904,098	114,188
11	options sold					
12						
13	Deferred Liability for Transferred					
14	Non-Qualified Plan Benefits	926,385	421	70,271		856,114
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
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33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	1,252,029		912,600	913,439	1,252,868

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 2011/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	(k)	
							1
							2
							3
							4
							5
							6
							7
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							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	519,679,362	81,528,499	19,555,487
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	519,679,362	81,528,499	19,555,487
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	519,679,362	81,528,499	19,555,487
10	Classification of TOTAL			
11	Federal Income Tax	428,579,570	66,324,518	16,128,040
12	State Income Tax	83,403,340	13,907,866	3,127,926
13	Local Income Tax	7,696,452	1,296,115	299,521

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 2011/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
		190, 182.3	27,706,436			553,945,938	2
							3
							4
			27,706,436			553,945,938	5
							6
							7
							8
			27,706,436			553,945,938	9
							10
			14,192,090			464,583,958	11
			12,373,799			81,809,481	12
			1,140,547			7,552,499	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 2011/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	54,487,577		
4	Price Risk Management	75,585,442	2,821,118	1,262,139
5	Regulatory Assets	108,998,651	53,895,821	34,510,284
6	Regulatory Liabilities		420,446	8,274,142
7	Other	92,776,646	2,662,982	78,134
8				
9	TOTAL Electric (Total of lines 3 thru 8)	331,848,316	59,800,367	44,124,699
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other	5,360,062		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	337,208,378	59,800,367	44,124,699
20	Classification of TOTAL			
21	Federal Income Tax	278,095,750	49,319,290	36,391,061
22	State Income Tax	54,118,572	9,565,161	7,057,814
23	Local Income Tax	4,994,056	915,916	675,824

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 2011/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
		190	18,482,772			36,004,805	3
		283	69,283,598			7,860,823	4
				190/283	144,975,046	273,359,234	5
						-7,853,696	6
		190/219/	76,364,301			18,997,193	7
							8
			164,130,671		144,975,046	328,368,359	9
							10
							11
							12
							13
							14
							15
							16
							17
424,165	760,413	190	3,518,723			1,505,091	18
424,165	760,413		167,649,394		144,975,046	329,873,450	19
							20
349,822	627,137		138,265,859		119,576,461	272,057,266	21
67,846	121,629		26,815,778		23,007,408	52,763,766	22
6,497	11,647		2,567,757		2,391,177	5,052,418	23

NOTES (Continued)

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

	Balance at Beginning of Year	Balance at End of Year
Biglow Revenue Requirement	$ 8,999,086	$ 281,614
Decoupling - SNA Deferral	4,821,600	471,357
FAS 71 Mark-to-Market	71,601,429	67,800,948
Price Risk Mgmt Deferral		77,490,478
FAS 158 Pension & Post Retirement		116,451,421
Miscellaneous	23,576,536	10,863,416
Total Other	$108,998,651	$273,359,234

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

	Balance at Beginning of Year	Balance at End of Year
Employee Benefits	$ 85,628,813	
Unamortized Loss on Reacquired Debt		$ 11,068,561
Other	7,147,833	7,928,632
Total Other	$ 92,776,646	$ 18,997,193

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

	Balance at Beginning of Year	Balance at End of Year
TOLI Gain/Loss	$ 3,970,594	$ 881,388
Other	1,389,465	623,703
Total Other	$ 5,360,059	$ 1,505,091

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS: Account Credited (c)	DEBITS: Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Excess Deferred Taxes	16,703,419	190	12,731,013		3,972,406
2						
3	Deferred Taxes on Investment Tax Credits	4,161	190	4,161		
4		2,714	283	2,714		
5						
6	Surplus CAA Allowances	672,300			431	672,731
7	(per OPUC Order No. 552 dtd 3/31/1993)					
8						
9	BPA Subscription Power - Balancing Account	3,703,565	456	51,182,528	56,298,547	8,819,584
10	(per OPUC Order No 08-175 dtd 3/20/2008)	1,879,820			46,943	1,926,763
11						
12	Gain on Asset Sales	2,531,740	254	1,827,077	128,906	833,569
13	(per OPUC Order No. 01-777 dtd 8/31/2001)					
14						
15	Gain on TRC Sales				1,864,141	1,864,141
16	(per OPUC Order No. 07-083 dtd 3/5/2007)					
17						
18	Power Cost Adjustment (Oct 2001 - Dec 2002)	1,886,723	555	1,813,709	44,246	117,260
19	(per Advice 10-22A dtd 12/28/2010;					
20	amortization period: 01/01/2011 - 12/31/2011)					
21						
22	Asset Retirement Obligations:					
23	Balancing Account	33,192,990	407.3	522,914	3,458,098	36,128,174
24						
25	Coyote Springs Major Maintenance Deferral	5,169,920	407.4	3,737,959	2,044,272	3,476,233
26	(per OPUC Order No. 01-777 dtd 8/31/2001;					
27	reauthorization OPUC Order No. 10-478					
28	dtd 12/17/2010)					
29						
30	ISFSI Pollution Control Tax Credit Deferral	21,640,479	407.4	18,096,269	3,066,753	6,610,963
31	(per OPUC Order No. 05-136 dtd 3/15/2005;					
32	amortization per Advice 10-22A dtd 12/28/2010;					
33	amortization period: 01/01/2011 - 12/31/2011)					
34						
35	Zero Interest Program Loan Repayments	908,500			182,055	1,090,555
36	(per Advice No. 05-19 dtd 12/20/2005)					
37						
38	Power Cost Adjustment Mechanism	(48,298)	456/182.3	98,710	147,008	
39	(per OPUC Order No. 07-015 dtd 1/12/2007)					
40						
1	Schedule 110 Energy Efficiency - Balancing Acct	343,128			360,239	703,367
2	(per Advice No. 07-25 dtd 5/20/2008)					
3						
4	SB1149 Residual Balance	1,463,104	407.4	1,436,041	33,694	60,757
41	TOTAL	92,510,469		92,806,167	68,843,757	68,548,059

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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)
5	(per Advice 10-22A dtd 12/28/2010;					
6	amortization period: 01/01/2011 - 12/31/2011)					
7						
8	Direct Access Open Enrollment - 2010	1,328,450	447	1,307,592	15,810	36,668
9	(per Advice 10-22A dtd 12/28/2010;					
10	amortization period: 01/01/2011 - 12/31/2011)					
11						
12	Direct Access Open Enrollment - 2011				1,132,525	1,132,525
13	(per Advice 10-23 dtd 11/15/2010 Tariff					
14	Schedule 128)					
15						
16	Sunway 3 Investment Deferral	886,750	407.4	45,480		841,270
17	(per UM 1480 dtd 04/01/2010;					
18	amortization over 20 years)					
19						
20	Interest on Portland Energy Solutions Note	241,004			20,089	261,093
21	(per OPUC Order No. 02-280 dtd 4/19/2002)					
22						
23						
24						
25						
26						
27						
28						
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30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	92,510,469		92,806,167	68,843,757	68,548,059

Schedule Page: 278 Line No.: 12 Column: c

Debit amount represents transfer of gains on Tradeable Renewable Credit(TRC) sales to separate Regulatory Liability for tracking purposes.

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

Represents transfer of gains on Tradeable Renewable Credit(TRC) sales to separate Regulatory Liability for tracking purposes.

Schedule Page: 278 Line No.: 38 Column: c

The debit residual balance remaining after the authorized amortization period was transferred to the Residual Deferred Account in Account 182.3, pursuant to OPUC Order No. 10-279 dated July 23, 2010.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	835,332,617	752,908,496
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	619,653,004	578,272,535
5	Large (or Ind.) (See Instr. 4)	227,626,835	219,992,392
6	(444) Public Street and Highway Lighting	17,782,195	17,783,471
7	(445) Other Sales to Public Authorities	738	6,133
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,700,395,389	1,568,963,027
11	(447) Sales for Resale	83,763,858	239,352,251
12	TOTAL Sales of Electricity	1,784,159,247	1,808,315,278
13	(Less) (449.1) Provision for Rate Refunds	5,955,065	-24,749,212
14	TOTAL Revenues Net of Prov. for Refunds	1,778,204,182	1,833,064,490
15	Other Operating Revenues		
16	(450) Forfeited Discounts	1,854,756	653,441
17	(451) Miscellaneous Service Revenues	2,351,445	2,184,731
18	(453) Sales of Water and Water Power	-17,839	-14,835
19	(454) Rent from Electric Property	6,763,866	6,970,988
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	37,242,620	87,170,062
22	(456.1) Revenues from Transmission of Electricity of Others	6,068,446	5,717,012
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	54,263,294	102,681,399
27	TOTAL Electric Operating Revenues	1,832,467,476	1,935,745,889

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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
7,732,514	7,452,448	719,977	717,719	2
				3
6,959,786	6,834,926	102,695	102,033	4
3,553,947	3,285,576	254	265	5
110,565	110,041	244	248	6
14	74	1	1	7
				8
				9
18,356,826	17,683,065	823,171	820,266	10
2,978,442	6,803,712	44	47	11
21,335,268	24,486,777	823,215	820,313	12
				13
21,335,268	24,486,777	823,215	820,313	14

Line 12, column (b) includes $ 7,862,000 of unbilled revenues.

Line 12, column (d) includes 25,283 MWH relating to unbilled revenues

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

Includes $11,831,059 in revenue related to the delivery of 348,805 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 a 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 2011, 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 $7,246,416 in revenue related to the delivery of 331,843 megawatt hours to customers of Electricity 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 2010, the "transition adjustment" credits provided to many commercial and industrial customers was less that 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(e).

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

Includes $8,723,100 in revenue related to the delivery of 639,633 megawatt hours to customers of Energy Services Suppliers (ESSs). For 2011, 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 a $2,601,778 in revenue related to the delivery of 717,596 megawatt hours to customers of Electricity Services Suppliers (ESSs). For 2010, the "transition adjustment" credits provided to many commercial and industrial customers was 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(e).

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 Payment Charges
Reconnect Charges
Field Service Charges
Meter Tamper Charges
Meter Test Charges
Meter Verification Charges
Switching Fees

This note applies to line 17, columns (b) and (c).

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

Other Electric Revenues consist of the following:

	2011	2010
BPA Subscription Power - Balancing Account	$ 51,182,528	$50,928,888
Biglow Canyon Phase 2 Deferral	(4,684,160)	(6,253,583)
Biglow Canyon Phase 3 Deferral	(17,262,014)	17,763,375
Residential Sch 123 SNA Deferral	(923,112)	4,002,593

Small Nonresidential Sch 123 SNA Deferral	(2,240,146)	1,830,290
Sch 123 LRRA Deferral	(285,043)	-
Power Cost Adjustment Mechanism	-	1,118,929
Boardman Power Cost Deferral	-	1,276,262
EE Program Delivery Contractor Services	1,701,106	1,457,297
PGE Share of Boardman Ash Sales	-	382,423
Income from Salmon Springs Hospitality Group	-	346,613
Park Revenues	515,797	500,395
Steam Sales	1,695,644	1,747,435
Gas for Resale	276,006	405,903
Oil for Resale	-	5,147,422
Wheeling Resale	6,275,911	5,390,250
Other - net	990,103	1,125,570
Totals	$ 37,242,620	$87,170,062

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
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36					
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38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	7,692,772	826,418,008	717,721	10,718	0.1074
3	9 Stable Rate Pilot	23,705	2,418,558	2,256	10,508	0.1020
4	15 Outdoor Area Lighting	6,864	1,499,051			0.2184
5	Residential Unbilled Revenue	9,173	4,997,000			0.5448
6	TOTAL Account 440	7,732,514	835,332,617	719,977	10,740	0.1080
7						
8	General Comm. and Ind. Sales:					
9	9 Stable Rate Pilot	1,501	161,257	63	23,825	0.1074
10	15 Comm. Outdoor Lighting	16,267	2,732,958			0.1680
11	32 Small Nonresidential	1,527,159	160,573,698	86,511	17,653	0.1051
12	38 Optional Time of Day -	30,131	3,617,441	273	110,370	0.1201
13	Large Nonresidential					
14	47 Irrigation - Drainage - Small	17,212	2,357,117	2,120	8,119	0.1369
15	49 Irrigation - Drainage - Large	53,828	5,043,252	1,005	53,560	0.0937
16	83-S Large Nonresidential	2,813,566	239,373,604	11,238	250,362	0.0851
17	85-S Large Nonresidential	1,972,424	153,310,848	1,179	1,672,964	0.0777
18	89-S Large Nonresidential	503,486	37,687,564	79	6,373,241	0.0749
19	483-S COS Opt-Out - Lrg. Nonresid		17,396	1		
20	485-S COS Opt-Out - Lrg. Nonresid	718	40,345	1	718,000	0.0562
21	485-S COS Opt-Out - Lrg. Nonresid		727,701	11		
22	489-S COS Opt-Out - Lrg. Nonresid	11,777	503,861	1	11,777,000	0.0428
23	489-S COS Opt-Out - Lrg. Nonresid		615,031	5		
24	532-S DAS - Small Nonresidential		39,103	12		
25	583-S DAS - Large Nonresidential		1,581,350	78		
26	585-S DAS - Large Nonresidential		8,075,352	115		
27	589-S DAS - Large Nonresidential		559,126	3		
28	Gen Comm. & Ind. Unbilled Revenue	11,717	2,636,000			0.2250
29	TOTAL Account 442 - Small	6,959,786	619,653,004	102,695	67,771	0.0890
30						
31	Large Industrial Power Sales:					
32	75 Partial Requirements Service	541,749	19,823,652	1	541,749,000	0.0366
33	83-P Large Nonresidential	1,398	102,269	1	1,398,000	0.0732
34	85-T Large Nonresidential		19,021	1		
35	85-P Large Nonresidential	304,568	22,312,555	141	2,160,057	0.0733
36	89-T Large Nonresidential	383,339	24,130,269	7	54,762,714	0.0629
37	89-P Large Nonresidential	2,318,564	152,447,969	87	26,650,161	0.0658
38	483-P COS Opt-Out - Lg. Nonresid		6,191			
39	485-P COS Opt-Out - Lg. Nonreside		29,839			
40	489-T COS Opt-Out - Lg. Nonreside		25,861	2		
41	TOTAL Billed	18,331,543	1,692,533,389	823,171	22,269	0.0923
42	Total Unbilled Rev.(See Instr. 6)	25,283	7,862,000	0	0	0.3110
43	TOTAL	18,356,826	1,700,395,389	823,171	22,300	0.0926

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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	489-P COS Opt-Out - Lg. Nonreside		4,199,030	5		
2	583-P DAS - Large Nonresidential		46,236			
3	585-T DAS - Large Nonresidential		4,600			
4	585-P DAS - Large Nonresidential		258,093	2		
5	589-T DAS - Large Nonresidential		9,705			
6	589-P DAS - Large Nonresidential		3,997,545	7		
7	Large Industrial Unbilled Revenue	4,329	214,000			0.0494
8	TOTAL Account 442 - Large	3,553,947	227,626,835	254	13,991,917	0.0640
9						
10	Various Public Street and					
11	Highway Lighting:					
12	Street Lighting	110,501	17,767,195	244	452,873	0.1608
13	Street Lighting Unbilled Rev	64	15,000			0.2344
14	TOTAL Account 444	110,565	17,782,195	244	453,135	0.1608
15						
16	Other Sales to Public Authorities					
17	Communication Devices Electr	14	738	1	14,000	0.0527
18	TOTAL Account 445	14	738	1	14,000	0.0527
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30						
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32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	18,331,543	1,692,533,389	823,171	22,269	0.0923
42	Total Unbilled Rev.(See Instr. 6)	25,283	7,862,000	0	0	0.3110
43	TOTAL	18,356,826	1,700,395,389	823,171	22,300	0.0926

Schedule Page: 304 Line No.: 16 Column: a
Rate Schedule 83 complete title: Large Nonresidential Standard Service (31 - 200 kW).

Schedule Page: 304 Line No.: 17 Column: a
Rate schedule 85 complete title: Large Nonresidential Standard Service (201 - 1,000 kW).

Schedule Page: 304 Line No.: 18 Column: a
Rate schedule 89 complete title: Large Nonresidential (>1,000 kW) Standard Service.

Schedule Page: 304 Line No.: 19 Column: a
Rate Schedule 483 complete title: Large Nonresidential (<1,000 kW) Cost of Service Opt-out.

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

Schedule Page: 304 Line No.: 20 Column: a
Rate Schedule 485 complete title: Large Nonresidential (<1,000 kW) Cost of Service Opt-out.

Schedule Page: 304 Line No.: 20 Column: b
Customers on this rate schedule can choose to purchase their energy from an Electricity Service Supplier (ESS) or PGE. In 2011, this customer purchased its energy from PGE.

Schedule Page: 304 Line No.: 21 Column: a
Rate Schedule 485 complete title: Large Nonresidential (<1,000 kW) Cost of Service Opt-out.

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

Schedule Page: 304 Line No.: 22 Column: a
Rate Schedule 489 complete title: Large Nonresidential (>1,000 kW) Cost of Service Opt-out.

Schedule Page: 304 Line No.: 22 Column: b
Customers on this rate schedule can choose to purchase their energy from an Electricity Service Supplier (ESS) or PGE. In 2011, this customer purchased its energy from PGE.

Schedule Page: 304 Line No.: 23 Column: a
Footnote Linked. See note on 304, Row: 22, col/item:

Schedule Page: 304 Line No.: 23 Column: b
Customers on this rate schedule can choose to purchase their energy from an Electricity Service Supplier (ESS) or PGE. PGE continues to serve these customers by delivering the energy purchased from ESSs.

Schedule Page: 304 Line No.: 24 Column: a
Rate Schedule 532 complete title: Small Nonresidential Direct Access Service.

Schedule Page: 304 Line No.: 24 Column: b
Customers on this rate schedule purchase their energy from Electricity Service Suppliers (ESSs). PGE continues to serve these customers by delivering the energy purchased from ESSs.

Schedule Page: 304 Line No.: 25 Column: a
Rate Schedule 583 complete title: Large Nonresidential Direct Access Service (31 - 200 kW).

Schedule Page: 304 Line No.: 25 Column: b
Customers on this rate schedule purchase their energy from Electricity Service Suppliers (ESSs). PGE continues to serve these customers by delivering the energy purchased from ESSs.

Schedule Page: 304 Line No.: 26 Column: a
Rate Schedule 585 complete title: Large Nonresidential Direct Access Service (201 - 1,000 kW).

Schedule Page: 304 Line No.: 26 Column: b

Customers on this rate schedule purchase their energy from Electricity Service Suppliers (ESSs). PGE continues to serve these customers by delivering the energy purchased from ESSs.

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

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

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

Customers on this rate schedule purchase their energy from Electricity Service Suppliers (ESSs). PGE continues to serve these customers by delivering the energy purchased from ESSs.

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

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

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

Rate schedule 85 complete title: Large Nonresidential Standard Service (201 - 1,000 kW).

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

Rate schedule 85 complete title: Large Nonresidential Standard Service (201 - 1,000 kW).

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

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

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

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

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

Rate Schedule 483 complete title: Large Nonresidential (<1,000 kW) Cost of Service Opt-out.

Schedule Page: 304 Line No.: 38 Column: b

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

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

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

Schedule Page: 304 Line No.: 39 Column: b

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

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

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

Schedule Page: 304 Line No.: 40 Column: b

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

Schedule Page: 304.1 Line No.: 1 Column: a

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

Schedule Page: 304.1 Line No.: 1 Column: b

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

Schedule Page: 304.1 Line No.: 2 Column: a

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

Schedule Page: 304.1 Line No.: 2 Column: b

Customers on this rate schedule purchase their energy from Electricity Service Suppliers (ESSs). PGE continues to serve these customers by delivering the energy purchased from

ESSs.

Schedule Page: 304.1 Line No.: 3 Column: a

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

Schedule Page: 304.1 Line No.: 3 Column: b

Customers on this rate schedule purchase their energy from Electricity Service Suppliers (ESSs). PGE continues to serve these customers by delivering the energy purchased from ESSs.

Schedule Page: 304.1 Line No.: 4 Column: a

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

Schedule Page: 304.1 Line No.: 4 Column: b

Customers on this rate schedule purchase their energy from Electricity Service Suppliers (ESSs). PGE continues to serve these customers by delivering the energy purchased from ESSs.

Schedule Page: 304.1 Line No.: 5 Column: a

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

Schedule Page: 304.1 Line No.: 5 Column: b

Customers on this rate schedule purchase their energy from Electricity Service Suppliers (ESSs). PGE continues to serve these customers by delivering the energy purchased from ESSs.

Schedule Page: 304.1 Line No.: 6 Column: a

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

Schedule Page: 304.1 Line No.: 6 Column: b

Customers on this rate schedule purchase their energy from Electricity Service Suppliers (ESSs). PGE continues to serve these customers by delivering the energy purchased from ESSs.

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 2011/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (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	BNP Paribas Energy	SF	WSPP-1	NA	NA	NA
8	Barclays Bank	SF	WSPP-1	NA	NA	NA
9	Black Hills Power	SF	WSPP-1	NA	NA	NA
10	Bonneville Power Administration	SF	WSPP-1	NA	NA	NA
11	BP Energy Company	SF	PGE-11	NA	NA	NA
12	Burbank, City of	SF	WSPP-1	NA	NA	NA
13	California Independent System Operat	SF	CAISO	NA	NA	NA
14	Calpine Energy Services	SF	PGE-11	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
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LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
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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	Cargill Alliant LLC	SF	WSPP-1	NA	NA	NA
2	Citigroup Energy Inc.	SF	WSPP-1	NA	NA	NA
3	Clatskanie County PUD, Washington	SF	WSPP-1	NA	NA	NA
4	Constellation Energy Commodities	SF	PGE-11	NA	NA	NA
5	CP Energy Marketing	SF	WSPP-1	NA	NA	NA
6	DB Energy Trading LLC	SF	WSPP-1	NA	NA	NA
7	Douglas County, PUD No. 1, Washingto	SF	WSPP-1	NA	NA	NA
8	EDF Trading NA	SF	WSPP-1	NA	NA	NA
9	Enmax	SF	PGE-11	NA	NA	NA
10	Eugene Water & Electric Board	SF	WSPP-1	NA	NA	NA
11	Exelon	SF	WSPP-1	NA	NA	NA
12	Glendale, City of	LF	PGE-78	19	19	19
13	Glendale, City of	SF	WSPP-1	NA	NA	NA
14	Grant County, PUD No. 2, Washington	SF	WSPP-1	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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:
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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.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Iberdrola Renewables	SF	PGE-11	NA	NA	NA
2	Idaho Power Company	SF	WSPP-1	NA	NA	NA
3	J. Aron Company	SF	PGE-11	NA	NA	NA
4	JP Morgan Ventures	SF	WSPP-1	NA	NA	NA
5	Load Balance Energy	OS	OATT	NA	NA	NA
6	Los Angeles Depart Water Power	SF	WSPP-1	NA	NA	NA
7	Macquarie Cook Power	SF	WSPP-1	NA	NA	NA
8	Modesto Irrigation District	SF	WSPP-1	NA	NA	NA
9	Morgan Stanley Capital Group	SF	PGE-11	NA	NA	NA
10	NASDAQ OMX Commodities	SF	WSPP-1	NA	NA	NA
11	Northern California Power Agency	SF	WSPP-1	NA	NA	NA
12	NorthPoint Energy Solutions	SF	WSPP-1	NA	NA	NA
13	NorthWestern Corporation	SF	WSPP-1	NA	NA	NA
14	Okanogan County PUD, Washington	SF	WSPP-1	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
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Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Pacific Northwest Generating Company	SF	WSPP-1	NA	NA	NA
2	PacifiCorp	LU	PGE-11	NA	NA	NA
3	PacifiCorp	SF	PGE-11	NA	NA	NA
4	Powerex	SF	PGE-11	NA	NA	NA
5	PPL Energy Plus	SF	PGE-11	NA	NA	NA
6	Public Service of Colorado	SF	WSPP-1	NA	NA	NA
7	Public Utility District No. 1 of Cla	SF	WSPP-1	NA	NA	NA
8	Puget Sound Energy	SF	WSPP-1	NA	NA	NA
9	Rainbow Energy Marketing	SF	WSPP-1	NA	NA	NA
10	Redding, City of	SF	WSPP-1	NA	NA	NA
11	Roseville, City of	SF	WSPP-1	NA	NA	NA
12	Sacramento Municipal Utility Distric	SF	WSPP-1	NA	NA	NA
13	San Diego Gas & Electric Company	SF	WSPP-1	NA	NA	NA
14	Seattle City Light	SF	WSPP-1	NA	NA	NA
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Shell Energy NA	SF	WSPP-1	NA	NA	NA
2	Sierra Pacific	SF	WSPP-1	NA	NA	NA
3	Silicon Valley Power	SF	WSPP-1	NA	NA	NA
4	Snohomish County, PUD No.1, Washingt	SF	WSPP-1	NA	NA	NA
5	Southern California Edison	SF	PGE-11	NA	NA	NA
6	Tacoma, City of	SF	WSPP-1	NA	NA	NA
7	The Energy Authority	SF	WSPP-1	NA	NA	NA
8	TransAlta Energy Marketing	SF	PGE-11	NA	NA	NA
9	TransCanada Power	SF	WSPP-1	NA	NA	NA
10	Turlock Irrigation District	SF	WSPP-1	NA	NA	NA
11	Western Area Power Authority	SF	WSPP-1	NA	NA	NA
12	Reserve			NA	NA	NA
13	Direct Access Deferral - 2011			NA	NA	NA
14	Direct Access Amortization			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 2011/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1						
2	Portland General Electric Company	SF	OA96137	396	NA	NA
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
	740,091	-554,150		185,941	2
					3
					4
					5
72,854		1,954,886		1,954,886	6
3,600		102,320		102,320	7
38,060		1,188,728		1,188,728	8
1,368		58,261		58,261	9
50,922		1,272,761		1,272,761	10
10,850		306,184		306,184	11
50,240		1,164,639		1,164,639	12
387,906		10,175,021		10,175,021	13
227,706		5,651,284		5,651,284	14
0	740,091	-554,150	0	185,941	
2,998,199	7,392,415	76,065,668	119,834	83,577,917	
2,998,199	**8,132,506**	**75,511,518**	**119,834**	**83,763,858**	

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.
63,171		2,194,626		2,194,626	1
32,744		1,068,584		1,068,584	2
10,878		188,979		188,979	3
74,619		1,621,314		1,621,314	4
1,337		32,760		32,760	5
4,400		129,100		129,100	6
401		13,315		13,315	7
63,660		1,449,628		1,449,628	8
70		2,740		2,740	9
9,787		195,116		195,116	10
2,400		84,180		84,180	11
96,771	4,850,000	2,459,863		7,309,863	12
13,273		294,163		294,163	13
12,140		308,139		308,139	14
0	740,091	-554,150	0	185,941	
2,998,199	7,392,415	76,065,668	119,834	83,577,917	
2,998,199	**8,132,506**	**75,511,518**	**119,834**	**83,763,858**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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.
220,523		5,719,732		5,719,732	1
37,422		829,052		829,052	2
800		21,400		21,400	3
8,118		228,413		228,413	4
15,625			363,989	363,989	5
96,370		1,652,925		1,652,925	6
117,499		3,685,050		3,685,050	7
10,600		273,835		273,835	8
255,404		5,371,336		5,371,336	9
22,425		647,200		647,200	10
11,565		219,299		219,299	11
1,444		19,660		19,660	12
48,403		1,423,160		1,423,160	13
795		26,110		26,110	14
0	740,091	-554,150	0	185,941	
2,998,199	7,392,415	76,065,668	119,834	83,577,917	
2,998,199	**8,132,506**	**75,511,518**	**119,834**	**83,763,858**	

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
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4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
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.
1,118		28,455		28,455	1
17,001			225,099	225,099	2
52,783		1,430,085		1,430,085	3
111,507		2,059,874		2,059,874	4
58,355		1,584,369		1,584,369	5
1,200		168		168	6
440		14,848		14,848	7
41,893		1,209,945		1,209,945	8
12,728		314,094		314,094	9
3,973		110,894		110,894	10
6,305		130,051		130,051	11
67,229		1,665,195		1,665,195	12
1,224		195,020		195,020	13
5,565		142,000		142,000	14
0	740,091	-554,150	0	185,941	
2,998,199	7,392,415	76,065,668	119,834	83,577,917	
2,998,199	**8,132,506**	**75,511,518**	**119,834**	**83,763,858**	

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 2011/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
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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.
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demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
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10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
116,388		4,248,186		4,248,186	1
5,798		136,303		136,303	2
10,411		210,771		210,771	3
2,575		75,090		75,090	4
124,625		4,178,051		4,178,051	5
2,150		37,515		37,515	6
7,238		227,783		227,783	7
148,121		3,342,486		3,342,486	8
56,980		1,546,306		1,546,306	9
29,950		662,329		662,329	10
16,735		431,474		431,474	11
			-200,000	-200,000	12
			-1,087,790	-1,087,790	13
			818,536	818,536	14
0	740,091	-554,150	0	185,941	
2,998,199	7,392,415	76,065,668	119,834	83,577,917	
2,998,199	**8,132,506**	**75,511,518**	**119,834**	**83,763,858**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
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demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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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
19,757	2,542,415	50,613		2,593,028	2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
0	740,091	-554,150	0	185,941	
2,998,199	7,392,415	76,065,668	119,834	83,577,917	
2,998,199	**8,132,506**	**75,511,518**	**119,834**	**83,763,858**	

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.: 12 Column: b

The contract with the City of Glendale expires on 9/30/12.

Schedule Page: 310.2 Line No.: 5 Column: j

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

Schedule Page: 310.3 Line No.: 2 Column: j

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

Schedule Page: 310.4 Line No.: 12 Column: j

Reserve relating to litigation.

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

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

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

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

Schedule Page: 310.5 Line No.: 2 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.

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	4,022,697	8,899,536
5	(501) Fuel	69,315,036	72,804,356
6	(502) Steam Expenses	3,660,073	
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses	6,092,141	1,637,763
11	(507) Rents	31,254	
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	83,121,201	83,341,655
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	3,104,142	16,632,220
16	(511) Maintenance of Structures	949,776	
17	(512) Maintenance of Boiler Plant	5,203,988	
18	(513) Maintenance of Electric Plant	11,050,617	
19	(514) Maintenance of Miscellaneous Steam Plant	2,360,138	25,007
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	22,668,661	16,657,227
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	105,789,862	99,998,882
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	194,281	1,623,351
45	(536) Water for Power	327,371	217,685
46	(537) Hydraulic Expenses	3,449,062	2,668,682
47	(538) Electric Expenses	1,024,174	
48	(539) Miscellaneous Hydraulic Power Generation Expenses	2,138,259	1,971,169
49	(540) Rents	31,962	-788,349
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	7,165,109	5,692,538
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	567,259	4,741,648
54	(542) Maintenance of Structures	79,044	
55	(543) Maintenance of Reservoirs, Dams, and Waterways	726,888	
56	(544) Maintenance of Electric Plant	659,706	
57	(545) Maintenance of Miscellaneous Hydraulic Plant	2,239,000	779,749
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	4,271,897	5,521,397
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	11,437,006	11,213,935

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	7,313,627	6,383,378
63	(547) Fuel	204,684,976	270,356,987
64	(548) Generation Expenses	2,430,171	
65	(549) Miscellaneous Other Power Generation Expenses	3,037,578	6,301,942
66	(550) Rents	283,347	498,277
67	TOTAL Operation (Enter Total of lines 62 thru 66)	217,749,699	283,540,584
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	700,850	
70	(552) Maintenance of Structures	43,736	
71	(553) Maintenance of Generating and Electric Plant	24,447,873	20,648,614
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	468,014	61,877
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	25,660,473	20,710,491
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	243,410,172	304,251,075
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	443,015,041	570,657,683
77	(556) System Control and Load Dispatching	1,010,832	2,514,903
78	(557) Other Expenses	16,733,513	15,138,169
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	460,759,386	588,310,755
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	821,396,426	1,003,774,647
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,402,389	2,468,042
84	(561) Load Dispatching		848
85	(561.1) Load Dispatch-Reliability	9,446	
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	647,892	669,855
87	(561.3) Load Dispatch-Transmission Service and Scheduling	746,734	819,387
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	157,556	137,283
90	(561.6) Transmission Service Studies	4,540	38,791
91	(561.7) Generation Interconnection Studies	191,289	217,923
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	162,847	22,579
94	(563) Overhead Lines Expenses	836,342	
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	68,710,884	69,074,968
97	(566) Miscellaneous Transmission Expenses	2,667,110	2,746,813
98	(567) Rents	2,883,272	2,478,805
99	TOTAL Operation (Enter Total of lines 83 thru 98)	79,420,301	78,675,294
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	70,892	
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software	1,400,466	1,651,142
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	828,543	896,032
108	(571) Maintenance of Overhead Lines	894,616	1,701,485
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of lines 101 thru 110)	3,194,517	4,248,659
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	82,614,818	82,923,953

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
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	7,975,466	8,784,660
135	(581) Load Dispatching	1,069,993	
136	(582) Station Expenses	965,510	786,784
137	(583) Overhead Line Expenses	378,721	
138	(584) Underground Line Expenses	1,924,681	1,792,761
139	(585) Street Lighting and Signal System Expenses	1,653,750	2,817,136
140	(586) Meter Expenses	1,757,941	965,402
141	(587) Customer Installations Expenses	1,963,468	1,855,477
142	(588) Miscellaneous Expenses	5,689,758	406,678
143	(589) Rents	1,543,511	1,543,349
144	TOTAL Operation (Enter Total of lines 134 thru 143)	24,922,799	18,952,247
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	333,858	1,250,966
147	(591) Maintenance of Structures	160,104	196,069
148	(592) Maintenance of Station Equipment	2,710,470	2,767,823
149	(593) Maintenance of Overhead Lines	30,386,262	27,850,887
150	(594) Maintenance of Underground Lines	4,382,927	5,115,498
151	(595) Maintenance of Line Transformers	164,001	
152	(596) Maintenance of Street Lighting and Signal Systems	820,734	
153	(597) Maintenance of Meters	261,604	89,108
154	(598) Maintenance of Miscellaneous Distribution Plant	15,461,186	11,417,558
155	TOTAL Maintenance (Total of lines 146 thru 154)	54,681,146	48,687,909
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	79,603,945	67,640,156
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision		
160	(902) Meter Reading Expenses	1,267,077	-536,169
161	(903) Customer Records and Collection Expenses	40,463,431	38,200,576
162	(904) Uncollectible Accounts	10,187,452	6,491,987
163	(905) Miscellaneous Customer Accounts Expenses	3,361,238	4,198,250
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	55,279,198	48,354,644

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	9,913,514	8,220,350
169	(909) Informational and Instructional Expenses	2,896,148	2,352,508
170	(910) Miscellaneous Customer Service and Informational Expenses		
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	12,809,662	10,572,858
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	43,430,089	41,010,361
182	(921) Office Supplies and Expenses	26,043,136	21,689,380
183	(Less) (922) Administrative Expenses Transferred-Credit	10,514,505	12,228,681
184	(923) Outside Services Employed	10,912,889	5,998,386
185	(924) Property Insurance	4,414,238	4,214,250
186	(925) Injuries and Damages	5,306,342	7,574,002
187	(926) Employee Pensions and Benefits	49,241,002	43,339,260
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	7,957,388	6,248,074
190	(929) (Less) Duplicate Charges-Cr.	1,983,633	1,927,695
191	(930.1) General Advertising Expenses	192,698	1,504,649
192	(930.2) Miscellaneous General Expenses	6,942,066	6,365,159
193	(931) Rents	3,957,345	4,102,804
194	TOTAL Operation (Enter Total of lines 181 thru 193)	145,899,055	127,889,949
195	Maintenance		
196	(935) Maintenance of General Plant	1,754,270	1,426,255
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	147,653,325	129,316,204
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	1,199,357,374	1,342,582,462

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PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Avista Corp. - AVWP (was WWP)	SF	WSPP-1	NA	NA	NA
2	BNP Paribas Energy	SF	WSPP-1	NA	NA	NA
3	Barclays Bank PLC - BARC	SF	WSPP-1	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	Bonneville Power Administration	EX	PGE-202	NA	NA	NA
8	BP Energy Company	SF	PGE-11	NA	NA	NA
9	Burbank, City of	SF	WSPP-1	NA	NA	NA
10	California Independent System Operator	SF	CAISO	NA	NA	NA
11	Calpine Energy Services	SF	PGE-11	NA	NA	NA
12	Cargill Alliant LLC	SF	WSPP-1	NA	NA	NA
13	Chelan County, PUD No. 1, Washington	LU	Rocky Reach	NA	NA	NA
14	Chelan County, PUD No. 1, Washington	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 2011/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Chelan County, PUD No. 1, Washington	EX	PGE-71	NA	NA	NA
2	Citigroup Energy	SF	WSPP-1	NA	NA	NA
3	Clatskanie County PUD	SF	WSPP-1	NA	NA	NA
4	Constellation Energy Commodities	SF	PGE-11	NA	NA	NA
5	Covanta Marion	LU	QF83-118	NA	NA	NA
6	CP Energy Marketing (US)	SF	WSPP-1	NA	NA	NA
7	DB Energy Trading LLC	SF	WSPP-1	NA	NA	NA
8	Douglas County, PUD No. 1, Washington	LU	Wells	NA	NA	NA
9	Douglas County, PUD No. 1, Washington	LF	Wells	NA	NA	NA
10	Douglas County, PUD No. 1, Washington	SF	WSPP-1	NA	NA	NA
11	EDF Trading North America, LLC	SF	WSPP-1	NA	NA	NA
12	ESI Vansycle Partners, LP	LU	WSPP-1	NA	NA	NA
13	Eugene Water & Electric Board	LU	WSPP-1	10	10	10
14	Eugene Water & Electric Board	OS	ER94-717	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 2011/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Eugene Water & Electric Board	SF	WSPP-1	NA	NA	NA
2	Eugene Water & Electric Board	EX	WSPP-1	NA	NA	NA
3	Exelon Generation Co.	SF	WSPP-1	NA	NA	NA
4	Glendale, City of	SF	WSPP-1	NA	NA	NA
5	Grant County, PUD No. 2, Washington	LU	Wanapum	NA	NA	NA
6	Grant County, PUD No. 2, Washington	LU	Priest Rapids	NA	NA	NA
7	Grant County, PUD No. 2, Washington	SF	WSPP-1	NA	NA	NA
8	Hinson Power Company	SF	WSPP-1	NA	NA	NA
9	Iberdrola Renewables	SF	PGE-11	NA	NA	NA
10	Iberdrola Renewables	LU	PGE-11	NA	NA	NA
11	Idaho Power Company	SF	WSPP-1	NA	NA	NA
12	JP Morgan Ventures	SF	WSPP-1	NA	NA	NA
13	Load Balance Energy	OS	OATT	NA	NA	NA
14	Los Angeles Depart Water Power	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 2011/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Macquarie Cook Power	SF	WSPP-1	NA	NA	NA
2	Merrill Lynch Commodities	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	Morgan Stanley Capital Group	LF	PGE-11	NA	NA	NA
6	NASDAQ OMX	SF	WSPP-1	NA	NA	NA
7	NextEra Energy Power Marketing, LLC	LF	WSPP-1	NA	NA	NA
8	Noble Americas Gas & Power	SF	WSPP-1	NA	NA	NA
9	Northern California Power Agency	SF	WSPP-1	NA	NA	NA
10	NorthPoint Energy Solutions Inc	SF	WSPP-1	NA	NA	NA
11	NorthWestern Corporation	SF	WSPP-1	NA	NA	NA
12	Okanogan County PUD, Washington	SF	WSPP-1	NA	NA	NA
13	Pacific Gas & Electric Company	SF	WSPP-1	NA	NA	NA
14	Pacific Northwest Generating Company	SF	WSPP-1	NA	NA	NA
	Total					

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PURCHASED POWER (Account 555)
(Including power exchanges)

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1	PacifiCorp	RQ	PP&L 147	NA	NA	NA
2	PacifiCorp	SF	PGE-11	NA	NA	NA
3	PaTu Wind	LU	WSPP-1	NA	NA	NA
4	Portland, City of	LU	#2821	NA	NA	NA
5	Powerex	SF	PGE-11	NA	NA	NA
6	PPL Energy Plus	SF	PGE-11	NA	NA	NA
7	Public Service Company of Colorado	SF	WSPP-1	NA	NA	NA
8	Public Utility District No. 1 of Clark	SF	WSPP-1	NA	NA	NA
9	Puget Sound Energy	SF	WSPP-1	NA	NA	NA
10	Rainbow Energy Marketing	SF	WSPP-1	NA	NA	NA
11	Redding, City of	SF	WSPP-1	NA	NA	NA
12	Roseville, City of	SF	WSPP-1	NA	NA	NA
13	Sacramento Municipal Utility District	SF	WSPP-1	NA	NA	NA
14	San Diego Gas & Electric Company	SF	WSPP-1	NA	NA	NA
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Seattle City Light	SF	WSPP-1	NA	NA	NA
2	Shell Energy	SF	WSPP-1	NA	NA	NA
3	Sierra Pacific	SF	WSPP-1	NA	NA	NA
4	Silicon Valley Power	SF	WSPP-1	NA	NA	NA
5	Snohomish County, PUD No. 1, Washingt	SF	WSPP-1	NA	NA	NA
6	Southern California Edison	SF	PGE-11	NA	NA	NA
7	Spokane Energy, LLC	LF	PGE-82	150	150	144
8	Spokane Energy, LLC	EX	PGE-82	NA	NA	NA
9	Spokane Energy, LLC	SF	WSPP-1	NA	NA	NA
10	Tacoma, City of	SF	WSPP-1	NA	NA	NA
11	The Energy Authority	SF	WSPP-1	NA	NA	NA
12	TransAlta Energy Marketing	SF	PGE-11	NA	NA	NA
13	TransAlta Energy Marketing	LF	PGE-11	NA	NA	NA
14	TransCanada Energy Marketing	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 2011/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	Turlock Irrigation District	SF	WSPP-1	NA	NA	NA
2	Warm Springs Power Enterprises	LU	WSPP-1	NA	NA	NA
3	Western Area Power Authority	SF	WSPP-1	NA	NA	NA
4	Yamhill Solar	LU	Yamhill	NA	NA	NA
5	Lake Oswego Corporation	LU	201	NA	NA	NA
6	Country Village Estates	OS	201	NA	NA	NA
7	Douglas Pegar	OS	201	NA	NA	NA
8	Domaine Drouhin	OS	201	NA	NA	NA
9	Von Land Co	OS	201	NA	NA	NA
10	Minikahada Hydropower Co	OS	201	NA	NA	NA
11	Starbucks	OS	201	NA	NA	NA
12	SunWay LLC	OS	201	NA	NA	NA
13	Solar Feed-In	OS	205	NA	NA	NA
14	Tualatin Valley Water Dist	OS	201	NA	NA	NA
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Oregon Heat	OS	203	NA	NA	NA
2	Load Curtailment Program			NA	NA	NA
3	Margin on Electric Financials			NA	NA	NA
4	PCA - 2002 Amortization			NA	NA	NA
5	Reserve Trading Credit Risk			NA	NA	NA
6	Green Power			NA	NA	NA
7						
8	Non-cash exchanges					
9						
10						
11						
12						
13						
14						
	Total					

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

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

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

MegaWatt Hours Purchased (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)	
53,690				1,879,366		1,879,366	1
26,000				533,548		533,548	2
312,200				4,998,700		4,998,700	3
129				12,055	-8,250	3,805	4
603				17,442		17,442	5
344,219				6,218,815		6,218,815	6
	992						7
353,086				6,306,803		6,306,803	8
3,474				94,230		94,230	9
97,988				758,984		758,984	10
170,588				4,811,258		4,811,258	11
168,947				3,539,470		3,539,470	12
771,489				7,913,938		7,913,938	13
5,015				74,522		74,522	14
13,027,363	465,054	475,214	19,822,200	310,426,396	112,766,445	443,015,041	

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
	4,102	14,809					1
77,996				1,661,119		1,661,119	2
11,128				202,172		202,172	3
49,033				870,981		870,981	4
87,181				5,658,588		5,658,588	5
806				18,808		18,808	6
11,800				355,570		355,570	7
816,072				8,565,677		8,565,677	8
206,627				5,870,372		5,870,372	9
13,802				299,871		299,871	10
96,416				2,147,674		2,147,674	11
78,684				4,669,316		4,669,316	12
			1,030,200			1,030,200	13
498							14
13,027,363	465,054	475,214	19,822,200	310,426,396	112,766,445	443,015,041	

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

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

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362,822				8,339,222		8,339,222	1
	26,000	26,080					2
4,800				151,760		151,760	3
380				11,591		11,591	4
461,427							5
782,613				23,301,389		23,301,389	6
343,288				8,813,938		8,813,938	7
45,625				1,238,858		1,238,858	8
912,147				20,983,392		20,983,392	9
223,516				10,943,018		10,943,018	10
19,596				447,160		447,160	11
397,582				6,712,729		6,712,729	12
10,314				278,671		278,671	13
1,261				65,043		65,043	14
13,027,363	465,054	475,214	19,822,200	310,426,396	112,766,445	443,015,041	

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

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

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165,452				3,818,248		3,818,248	1
1,600				23,380		23,380	2
1,014				18,203		18,203	3
594,491				15,264,166		15,264,166	4
163,771				7,042,153		7,042,153	5
46,600				1,466,750		1,466,750	6
43,007				1,392,842		1,392,842	7
400				13,700		13,700	8
40				440		440	9
423				6,253		6,253	10
-55,885				214,544		214,544	11
6,465				116,777		116,777	12
20,800				511,728		511,728	13
436,985				7,296,336		7,296,336	14
13,027,363	465,054	475,214	19,822,200	310,426,396	112,766,445	443,015,041	

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
11,088				1,012,475		1,012,475	1
85,933				2,008,440		2,008,440	2
39,734				1,844,989		1,844,989	3
95,527				4,377,018		4,377,018	4
66,651				2,335,307		2,335,307	5
67,895				1,786,371		1,786,371	6
46,600				466,376		466,376	7
23,665				634,466		634,466	8
251,716				5,174,429		5,174,429	9
7,130				143,795		143,795	10
526				9,089		9,089	11
6				125		125	12
17,262				464,786		464,786	13
160				7,040		7,040	14
13,027,363	465,054	475,214	19,822,200	310,426,396	112,766,445	443,015,041	

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

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

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	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
120,646				2,752,077		2,752,077	1
577,820				13,454,608		13,454,608	2
1,543				62,085		62,085	3
43				1,280		1,280	4
41,894				860,032		860,032	5
51,700				1,376,817		1,376,817	6
			18,792,000			18,792,000	7
	433,960	434,325					8
60							9
103,028				2,193,333		2,193,333	10
149,739				3,021,886		3,021,886	11
992,631				27,084,538		27,084,538	12
875,606				34,866,258		34,866,258	13
1,650				58,200		58,200	14
13,027,363	465,054	475,214	19,822,200	310,426,396	112,766,445	443,015,041	

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)	
2,099				42,777		42,777	1
631,516				17,985,925		17,985,925	2
8,722				123,861		123,861	3
91				8,541	-8,250	291	4
97				3,063		3,063	5
6				248		248	6
278				17,190		17,190	7
102				6,650		6,650	8
228				15,111		15,111	9
367				22,636		22,636	10
24				1,183		1,183	11
2,929				168,688		168,688	12
2,268				76,054		76,054	13
108				7,079		7,079	14
13,027,363	465,054	475,214	19,822,200	310,426,396	112,766,445	443,015,041	

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 2011/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)	
270					11,674	11,674	1
					331,276	331,276	2
					106,553,392	106,553,392	3
					-1,813,709	-1,813,709	4
					-61,094	-61,094	5
					7,896,397	7,896,397	6
							7
					-134,991	-134,991	8
							9
							10
							11
							12
							13
							14
13,027,363	465,054	475,214	19,822,200	310,426,396	112,766,445	443,015,041	

Schedule Page: 326 Line No.: 4 Column: l
Delay damages due to late startup of the solar operations.

Schedule Page: 326 Line No.: 13 Column: c
Non jurisdictional utilities.

Schedule Page: 326 Line No.: 13 Column: g
Includes allocation to Canadian Entitlement and Fish Spill Replacement re: Pacific Northwest Coordination Agreement Canadian Entitlement - PUD NO. 1 Chelan County (39,942).

Schedule Page: 326.1 Line No.: 8 Column: c
Non jurisdictional utilities.

Schedule Page: 326.1 Line No.: 9 Column: b
The Douglas County contract expires on 8/31/18.

Schedule Page: 326.1 Line No.: 14 Column: g
Represents net of energy generated at EWEB's Stone Creek facility within PGE's control area and energy delivered to EWEB.

Schedule Page: 326.2 Line No.: 1 Column: c
Non jurisdictional utilities.

Schedule Page: 326.2 Line No.: 5 Column: c
Non jurisdictional utilities.

Schedule Page: 326.2 Line No.: 13 Column: a
Represents the value of energy delivered to the PGE control area from Electric Service Suppliers in excess of the ESS's actual load within the PGE control area.

Schedule Page: 326.3 Line No.: 5 Column: b
The Morgan Stanley contract expired on 9/30/11.

Schedule Page: 326.3 Line No.: 7 Column: b
The NextEra contract expires 12/31/15.

Schedule Page: 326.5 Line No.: 5 Column: c
Non jurisdictional utilities.

Schedule Page: 326.5 Line No.: 7 Column: b
The Spokane Energy, LLC contract expires on 12/31/16.

Schedule Page: 326.5 Line No.: 13 Column: b
The TransAlta Energy Marketing contract expires on 9/30/16.

Schedule Page: 326.6 Line No.: 4 Column: l
Delay damages due to late startup of the solar operations.

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.: 7 Column: b
Power purchased from customers who operate generation facilities with less that 100 KW capacity.

Schedule Page: 326.6 Line No.: 8 Column: b
Power purchased from customers who operate generation facilities with less that 100 KW capacity.

Schedule Page: 326.6 Line No.: 9 Column: b
Power purchased from customers who operate generation facilities with less that 100 KW capacity.

Schedule Page: 326.6 Line No.: 10 Column: b
Power purchased from customers who operate generation facilities with less that 100 KW capacity.

Schedule Page: 326.6 Line No.: 11 Column: b
Power purchased from customers who operate generation facilities with less that 100 KW capacity.

Schedule Page: 326.6 Line No.: 12 Column: b
Power purchased from customers who operate generation facilities with less that 100 KW capacity.

Schedule Page: 326.6 Line No.: 13 Column: b
Power purchased from customers who operate generation facilities with less that 100 KW capacity.

Schedule Page: 326.6 Line No.: 14 Column: b
Power purchased from customers who operate generation facilities with less that 100 KW capacity.

Schedule Page: 326.7 Line No.: 1 Column: l
In accordance with Schedule 203 tariff any excess credits will be transferred to Low Income Assistance Program.

Schedule Page: 326.7 Line No.: 2 Column: l
Power purchased under Load Curtailment Program.

Schedule Page: 326.7 Line No.: 3 Column: l
Margin on electric financial transactions.

Schedule Page: 326.7 Line No.: 4 Column: l
Amortization of remaining balance of the 2002 Power Cost Adjustment.

Schedule Page: 326.7 Line No.: 5 Column: l
Reserve for trading credit risk.

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

Consists of expenses related to the purchase of RECs and development of future renewable resources for PGE's Portfolio Options programs. Such expenses are fully offset by customer revenues.

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 2011/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Avista Corp-Washington Water Power	Bonneville Power Administration	Balancing Authority of North Cal	LFP
2	Avista Corp-Washington Water Power	Bonneville Power Administration	Bonneville Power Administration	LFP
3	Avista Corp-Washington Water Power	Bonneville Power Administration	California Independent System Opr	LFP
4	Avista Corp-Washington Water Power	Bonneville Power Administration	Sacramento Municipal Utility Dist	LFP
5	Barclay's Bank PLC	Bonneville Power Administration	California Independent System Opr	NF
6	Bonneville Power Administration	Bonneville Power Administration	Portland General Electric	FNO
7	Bonneville Power Administration	Bonneville Power Administration	Western Oregon Electric Coop	OLF
8	Bonneville Power Administration	Bonneville Power Administration	Other TVI Pumps	OLF
9	Bonneville Power Administration	Bonneville Power Administration	Canby Peoples Utility District	OLF
10	Bonneville Power Administration	Bonneville Power Administration	Columbia River PUD	OLF
11	Cargill Power Markets, LLC	Bonneville Power Administration	Balancing Authority of North Cal	SFP
12	Cargill Power Markets, LLC	Bonneville Power Administration	California Independent System Opr	SFP
13	Cargill Power Markets, LLC	Sacramento Municipal Utility Dist	Bonneville Power Administration	SFP
14	Cargill Power Markets, LLC	Bonneville Power Administration	California Independent System Opr	NF
15	Cargill Power Markets, LLC	Bonneville Power Administration	PacifiCorp	NF
16	Cargill Power Markets, LLC	Bonneville Power Administration	Sacramento Municipal Utility Dist	NF
17	Cargill Power Markets, LLC	Sacramento Municipal Utility Dist	Bonneville Power Administration	NF
18	Constellation Energy Commodities	Bonneville Power Administration	California Independent System Opr	SFP
19	Constellation Energy Commodities	Bonneville Power Administration	California Independent System Opr	NF
20	Citigroup Energy, Inc	Bonneville Power Administration	California Independent System Opr	NF
21	Constellation New Energy	Bonneville Power Administration	Portland General Electric	NF
22	EDF Trading North America, LLC	Bonneville Power Administration	California Independent System Opr	NF
23	Iberdrola Renewables Inc.	Bonneville Power Administration	California Independent System Opr	NF
24	Iberdrola Renewables Inc.	Bonneville Power Administration	Bonneville Power Administration	NF
25	JP Morgan Ventures Energy Corp	Bonneville Power Administration	California Independent System Opr	NF
26	Macquarie Cook Power Inc.	Balancing Authority of North Cal	Bonneville Power Administration	NF
27	Macquarie Cook Power Inc.	California Independent System Opr	Bonneville Power Administration	NF
28	Macquarie Cook Power Inc.	Sacramento Municipal Utility Dist	Bonneville Power Administration	NF
29	Macquarie Cook Power Inc.	Bonneville Power Administration	Balancing Authority of North Cal	NF
30	Macquarie Cook Power Inc.	Bonneville Power Administration	California Independent System Opr	NF
31	Macquarie Cook Power Inc.	Bonneville Power Administration	Sacramento Municipal Utility Dist	NF
32	Morgan Stanley Capital Group	Bonneville Power Administration	Balancing Authority of North Cal	NF
33	Morgan Stanley Capital Group	Bonneville Power Administration	California Independent System Opr	NF
34	Morgan Stanley Capital Group	Bonneville Power Administration	PacifiCorp	NF
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Morgan Stanley Capital Group	Bonneville Power Administration	Sacramento Municipal Utility Dist	NF
2	Morgan Stanley Capital Group	California Independent System Opr	Bonneville Power Administration	NF
3	Noble Americas Energy Solutions	Bonneville Power Administration	Portland General Electric	NF
4	PacifiCorp	PacifiCorp	Portland General Electric	OS
5	Powerex	Bonneville Power Administration	California Independent System Opr	LFP
6	Powerex	Bonneville Power Administration	PacifiCorp	LFP
7	Powerex	Bonneville Power Administration	Sacramento Municipal Utility Dist	LFP
8	Powerex	Bonneville Power Administration	Balancing Authority of North Cal	LFP
9	Powerex	Bonneville Power Administration	California Independent System Opr	NF
10	Powerex	Bonneville Power Administration	PacifiCorp	NF
11	Powerex	Bonneville Power Administration	Sacramento Municipal Utility Dist	NF
12	Powerex	Balancing Authority of North Cal	Bonneville Power Administration	NF
13	Powerex	California Independent System Opr	Bonneville Power Administration	NF
14	Powerex	Sacramento Municipal Utility Dist	Bonneville Power Administration	NF
15	Powerex	California Independent System Opr	Bonneville Power Administration	OS
16	Powerex	Bonneville Power Administration	California Independent System Opr	OS
17	Powerex	Bonneville Power Administration	Balancing Authority of North Cal	SFP
18	Powerex	Bonneville Power Administration	Bonneville Power Administration	SFP
19	Powerex	Bonneville Power Administration	California Independent System Opr	SFP
20	Powerex	Bonneville Power Administration	PacifiCorp	SFP
21	Powerex	Bonneville Power Administration	Sacramento Municipal Utility Dist	SFP
22	Puget Sound Energy	Balancing Authority of North Cal	Bonneville Power Administration	NF
23	Puget Sound Energy	Bonneville Power Administration	Bonneville Power Administration	NF
24	Puget Sound Energy	California Independent System Opr	Bonneville Power Administration	NF
25	Puget Sound Energy	Sacramento Municipal Utility Dist	Bonneville Power Administration	NF
26	Puget Sound Energy	Bonneville Power Administration	Balancing Authority of North Cal	NF
27	Puget Sound Energy	Bonneville Power Administration	California Independent System Opr	NF
28	Puget Sound Energy	Bonneville Power Administration	Sacramento Municipal Utility Dist	NF
29	Puget Sound Energy	California Independent System Opr	Bonneville Power Administration	SFP
30	Rainbow Energy Marketing Corp	California Independent System Opr	Bonneville Power Administration	NF
31	San Diego Gas and Electric	Bonneville Power Administration	Balancing Authority of North Cal	OLF
32	San Diego Gas and Electric	Bonneville Power Administration	California Independent System Opr	OLF
33	San Diego Gas and Electric	Bonneville Power Administration	Sacramento Municipal Utility Dist	OLF
34	Seattle City Light Marketing	Bonneville Power Administration	California Independent System Opr	NF
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	Balancing Authority of North Cal	LFP
2	Shell Energy North America (US), L.P.	Bonneville Power Administration	California Independent System Opr	LFP
3	Shell Energy North America (US), L.P.	Bonneville Power Administration	Sacramento Municipal Utility Dist	LFP
4	Shell Energy North America (US), L.P.	Balancing Authority of North Cal	Bonneville Power Administration	NF
5	Shell Energy North America (US), L.P.	Bonneville Power Administration	Balancing Authority of North Cal	NF
6	Shell Energy North America (US), L.P.	Bonneville Power Administration	Bonneville Power Administration	NF
7	Shell Energy North America (US), L.P.	Bonneville Power Administration	California Independent System Opr	NF
8	Shell Energy North America (US), L.P.	Bonneville Power Administration	Sacramento Municipal Utility Dist	NF
9	Shell Energy North America (US), L.P.	California Independent System Opr	Bonneville Power Administration	NF
10	Shell Energy North America (US), L.P.	California Independent System Opr	Bonneville Power Administration	OS
11	Souther California Edison	Bonneville Power Administration	California Independent System Opr	SFP
12	Souther California Edison	Bonneville Power Administration	California Independent System Opr	NF
13	Tacoma Power	Bonneville Power Administration	Balancing Authority of North Cal	NF
14	Tacoma Power	Bonneville Power Administration	California Independent System Opr	NF
15	Tacoma Power	Bonneville Power Administration	Sacramento Municipal Utility Dist	NF
16	The Energy Authority	Balancing Authority of North Cal	Bonneville Power Administration	NF
17	The Energy Authority	Bonneville Power Administration	Bonneville Power Administration	NF
18	The Energy Authority	Bonneville Power Administration	Balancing Authority of North Cal	NF
19	The Energy Authority	Bonneville Power Administration	California Independent System Opr	NF
20	Trans Alta Energy Marketing U.S. Inc.	Bonneville Power Administration	California Independent System Opr	SFP
21	Trans Alta Energy Marketing U.S. Inc.	Bonneville Power Administration	Balancing Authority of North Cal	NF
22	Trans Alta Energy Marketing U.S. Inc.	Bonneville Power Administration	California Independent System Opr	NF
23	Trans Alta Energy Marketing U.S. Inc.	Bonneville Power Administration	Sacramento Municipal Utility Dist	NF
24	Trans Alta Energy Marketing U.S. Inc.	California Independent System Opr	Bonneville Power Administration	NF
25	Trans Alta Energy Marketing U.S. Inc.	Sacramento Municipal Utility Dist	Bonneville Power Administration	NF
26	Turlock Irrigation District	Bonneville Power Administration	Portland General Electric	SFP
27	Turlock Irrigation District	Bonneville Power Administration	Balancing Authority of North Cal	NF
28	Turlock Irrigation District	Bonneville Power Administration	Sacramento Municipal Utility Dist	NF
29	Turlock Irrigation District	Sacramento Municipal Utility Dist	Bonneville Power Administration	NF
30	Accrual			AD
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 2011/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		89,604	89,604	1
8	John Day	Captain Jack		812	812	2
8	John Day	Malin500		767,421	767,421	3
8	John Day	Captain Jack		59,104	59,104	4
8	John Day	Malin500		850	850	5
8	Various Subs	Various Subs	127	65,495	62,715	6
72	Various Subs	Various Subs		13,560	13,348	7
72	Various Subs	Various Subs		6,403	6,303	8
72	Various Subs	Various Subs		181,239	178,411	9
72	Various Subs	Various Subs		262,449	258,354	10
8	John Day	Captain Jack		3,256	3,256	11
8	John Day	Malin500		11,436	11,436	12
8	Captain Jack	John Day		1,200	1,200	13
8	John Day	Malin500		3,422	3,422	14
8	John Day	Malin500		50	50	15
8	John Day	Captain Jack		1,545	1,545	16
8	Captain Jack	John Day		13,984	13,984	17
8	John Day	Malin500		31,978	31,978	18
8	John Day	Malin500		450	450	19
8	John Day	Malin500		32,873	32,873	20
8	Various Subs	Various Subs	122,281	70,079	73,225	21
8	John Day	Malin500		4,832	4,832	22
8	John Day	Malin500		2	2	23
8	KFallsGen	John Day		424	424	24
8	John Day	Malin500		119	119	25
8	Captain Jack	John Day		20	20	26
8	Malin500	John Day		90	90	27
8	Captain Jack	John Day		225	225	28
8	John Day	Captain Jack		1,314	1,314	29
8	John Day	Malin500		27,862	27,862	30
8	John Day	Captain Jack		240	240	31
8	John Day	Captain Jack		12,687	12,687	32
8	John Day	Malin500		66,072	66,072	33
8	John Day	Malin500		599	599	34
			1,869,020	**5,391,323**	**5,385,423**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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		2,271	2,271	1
8	Malin500	John Day		1,175	1,175	2
8	Various Subs	Various Subs	1,746,612	951,110	952,212	3
	John Day	Various Subs		3,406	3,273	4
8	John Day	Malin500		485,250	485,250	5
8	John Day	Malin500		216	216	6
8	John Day	Captain Jack		16,722	16,722	7
8	John Day	Captain Jack		1,034	1,034	8
8	John Day	Malin500		16,724	16,724	9
8	John Day	Malin500		132	132	10
8	John Day	Captain Jack		656	656	11
8	Captain Jack	John Day		117	117	12
8	Malin500	John Day		386	386	13
8	Captain Jack	John Day		54	54	14
8	Malin500	John Day		69	69	15
8	John Day	Malin500		12	12	16
8	John Day	Captain Jack		40,400	40,400	17
8	John Day	COBH		300	300	18
8	John Day	Malin500		281,542	281,542	19
8	John Day	Malin500		115	115	20
8	John Day	Captain Jack		54	54	21
8	Captain Jack	John Day		1,280	1,280	22
8	KFallsGen	John Day		308	308	23
8	Malin500	John Day		1,802	1,802	24
8	Captain Jack	John Day		145	145	25
8	John Day	Captain Jack		209	209	26
8	KFallsGen	John Day		2,583	2,583	27
8	John Day	Captain Jack		420	420	28
8	Malin500	John Day		92,858	92,858	29
8	Malin500	John Day		178	178	30
8	John Day	Captain Jack				31
8	John Day	Malin500		40,838	40,838	32
8	John Day	Captain Jack				33
8	John Day	Malin500		101	101	34
			1,869,020	**5,391,323**	**5,385,423**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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		574,936	574,936	1
8	John Day	Malin500		729,250	729,250	2
8	John Day	Captain Jack		211,610	211,610	3
8	Captain Jack	John Day		20	20	4
8	John Day	Captain Jack		295	295	5
8	KFallsGen	John Day		26	26	6
8	John Day	Malin500		23,598	23,598	7
8	John Day	Captain Jack		25	25	8
8	Malin500	John Day		8,214	8,214	9
8	Malin500	John Day		3,622	3,622	10
8	John Day	Malin500		10,742	10,742	11
8	John Day	Malin500		653	653	12
8	John Day	Captain Jack		312	312	13
8	John Day	Malin500		52	52	14
8	John Day	Captain Jack		888	888	15
8	Captain Jack	John Day		175	175	16
8	KFallsGen	John Day		388	388	17
8	John Day	Captain Jack		5,377	5,377	18
8	John Day	Malin500		1,121	1,121	19
8	John Day	Malin500		11,371	11,371	20
8	John Day	Captain Jack		289	289	21
8	John Day	Malin500		118,722	118,722	22
8	John Day	Captain Jack		85	85	23
8	Malin500	John Day		13,428	13,428	24
8	Captain Jack	John Day		1,778	1,778	25
8	BPAT.PGE	PGE		1	1	26
8	John Day	Captain Jack		4	4	27
8	John Day	Captain Jack		144	144	28
8	Captain Jack	John Day		34	34	29
						30
						31
						32
						33
						34
			1,869,020	**5,391,323**	**5,385,423**	

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.
	62,833		62,833	1
	569		569	2
	538,141		538,141	3
	41,446		41,446	4
	1,083		1,083	5
54,392		19,620	74,012	6
	57,683		57,683	7
	18,677		18,677	8
	184,070		184,070	9
	68,581		68,581	10
	6,222		6,222	11
	21,852		21,852	12
	2,293		2,293	13
	2,881		2,881	14
	42		42	15
	1,301		1,301	16
	11,771		11,771	17
	54,123		54,123	18
	18,331		18,331	19
	597		597	20
59,918			59,918	21
	5,901		5,901	22
	3		3	23
	540		540	24
	98		98	25
	20		20	26
	92		92	27
	229		229	28
	1,337		1,337	29
	28,354		28,354	30
	244		244	31
	15,255		15,255	32
	79,447		79,447	33
	720		720	34
970,150	**4,833,725**	**264,571**	**6,068,446**	

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.
	2,731		2,731	1
	1,413		1,413	2
855,840			855,840	3
		247,226	247,226	4
	1,025,148		1,025,148	5
	456		456	6
	35,327		35,327	7
	2,120		2,120	8
	34,281		34,281	9
	271		271	10
	1,345		1,345	11
	240		240	12
	791		791	13
	111		111	14
				15
				16
	25,927		25,927	17
	193		193	18
	180,678		180,678	19
	74		74	20
	35		35	21
	1,466		1,466	22
	353		353	23
	2,063		2,063	24
	166		166	25
	239		239	26
	2,958		2,958	27
	481		481	28
	97,478		97,478	29
	310		310	30
				31
	650,000		650,000	32
				33
	121		121	34
970,150	**4,833,725**	**264,571**	**6,068,446**	

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.
	487,767		487,767	1
	618,684		618,684	2
	179,527		179,527	3
	23		23	4
	345		345	5
	30		30	6
	27,614		27,614	7
	29		29	8
	9,612		9,612	9
				10
	38,555		38,555	11
	723		723	12
	476		476	13
	79		79	14
	1,354		1,354	15
	187		187	16
	414		414	17
	5,743		5,743	18
	1,197		1,197	19
	20,436		20,436	20
	321		321	21
	131,868		131,868	22
	94		94	23
	14,915		14,915	24
	1,975		1,975	25
	22		22	26
	5		5	27
	176		176	28
	42		42	29
		-2,275	-2,275	30
				31
				32
				33
				34
970,150	**4,833,725**	**264,571**	**6,068,446**	

Schedule Page: 328 Line No.: 1 Column: d
Contract with Avista Corporation - Washington Water Power expires 01/01/2013.
Schedule Page: 328 Line No.: 2 Column: d
Contract with Avista Corporation - Washington Water Power expires 01/01/2013.
Schedule Page: 328 Line No.: 3 Column: d
Contract with Avista Corporation - Washington Water Power expires 01/01/2013.
Schedule Page: 328 Line No.: 4 Column: d
Contract with Avista Corporation - Washington Water Power expires 01/01/2013.
Schedule Page: 328 Line No.: 6 Column: m
Represents monthly facility usage charges.
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 Line No.: 10 Column: d
Contract with Bonneville Power Administration continues until terminated.
Schedule Page: 328.1 Line No.: 4 Column: d
Represents monthly facility usage charges.
Schedule Page: 328.1 Line No.: 4 Column: e
Exchange agreement with PacifiCorp
Schedule Page: 328.1 Line No.: 4 Column: m
Represents monthly facility usage charges.
Schedule Page: 328.1 Line No.: 5 Column: d
Contract with Powerex expires 06/01/2013.
Schedule Page: 328.1 Line No.: 6 Column: d
Contract with Powerex expires 06/01/2013.
Schedule Page: 328.1 Line No.: 7 Column: d
Contract with Powerex expires 06/01/2013.
Schedule Page: 328.1 Line No.: 8 Column: d
Contract with Powerex expires 06/01/2013.
Schedule Page: 328.1 Line No.: 15 Column: d
Represents non-billed redirected MWHs of Powerex's SFP reservations.
Schedule Page: 328.1 Line No.: 16 Column: d
Represents non-billed redirected MWHs of Powerex's SFP reservations.
Schedule Page: 328.1 Line No.: 31 Column: d
Contract with San Diego Gas & Electric expires 12/31/2013.
Schedule Page: 328.1 Line No.: 32 Column: d
Contract with San Diego Gas & Electric expires 12/31/2013.
Schedule Page: 328.1 Line No.: 33 Column: d
Contract with San Diego Gas & Electric expires 12/31/2013.
Schedule Page: 328.2 Line No.: 1 Column: d
Contract with Shell Energy North America expires 06/01/2013.
Schedule Page: 328.2 Line No.: 2 Column: d
Contract with Shell Energy North America expires 06/01/2013.
Schedule Page: 328.2 Line No.: 3 Column: d
Contract with Shell Energy North America expires 06/01/2013.
Schedule Page: 328.2 Line No.: 10 Column: d
Represents non-billed redirected MWHs of Shell Energy North America's LFP reservations
Schedule Page: 328.2 Line No.: 30 Column: d

Represents true-up of prior period transactions

Schedule Page: 328.2 Line No.: 30 Column: m

Represents the difference between actual wheeling 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 2011/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					
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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 2011/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Avista Corp	NF	65,277	65,277		109,346		109,346
2	Bonneville Power Admin	LFP			48,178,129			48,178,129
3	Bonneville Power Admin	OS					17,779,830	17,779,830
4	Bonneville Power Admin	NF	161,565	161,565		361,590		361,590
5	BPA Amortization	FNS					196,416	196,416
6	Columbia River PUD	NF	8	8		3,915		3,915
7	Fale-Safe, Inc	OS					1,101,181	1,101,181
8	Idaho Power Company	NF	600	600		1,895		1,895
9	McMinnville Water & Lig	NF	1,720	1,720		9,019		9,019
10	Montana, State of	OS					675,828	675,828
11	Northwestern Corp	NF	29,991	29,991		137,824		137,824
12	PacifiCorp	OS					95,106	95,106
13	PacifiCorp	NF	4,230	4,230		23,373		23,373
14	PPL EnergyPlus	NF	1	1		3		3
15	Puget Sound Energy	NF	12,787	12,787		26,101		26,101
16	Salem Electric	OS					11,328	11,328
	TOTAL		276,179	276,179	48,178,129	673,066	19,859,689	68,710,884

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

The Bonneville Power Administration PTP Network contract expires on 12/31/14. The PTP contract for Slatt expires 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.: 5 Column: g

Represents amortization of deferred transmission costs related to transmission line access for the Glendale sales agreement, amortized over 25 years through 2012.

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.: 10 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.: 12 Column: g

Represents PacifiCorp's Linneman Transmission Services.

Schedule Page: 332 Line No.: 16 Column: g

Represents Ancillary Services provided by Salem Electric.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	1,911,433
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	847,598
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	1,103,110
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Involuntary Severance	745,014
7	Directors Pension	58,277
8	Directors Fees & Expenses	839,960
9	Directors & Officers Expenses	1,078,120
10	Misc Admin R&D Expenses	15,689
11	Misc Admin Expenses	35,562
12	Misc General Expenses Colstrip - PPL Montana	307,303
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	6,942,066

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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			19,275,881		19,275,881
2	Steam Production Plant	14,967,160	1,828,985			16,796,145
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	9,395,693	64			9,395,757
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	53,267,319	77,509			53,344,828
7	Transmission Plant	8,922,615	1,676			8,924,291
8	Distribution Plant	107,924,762	9,615			107,934,377
9	Regional Transmission and Market Operation					
10	General Plant	16,575,393	1,202,079			17,777,472
11	Common Plant-Electric					
12	TOTAL	211,052,942	3,119,928	19,275,881		233,448,751

B. Basis for Amortization Charges

Five-year and ten year amortization of computer software.
Five-year and twenty-five year amortization of permits.
Thirty-year, forty-five year, and fifty year amortization of hydro licensing costs.

On December 21, 2010, the FERC issued a forty year license for PGE's hydro projects on the Clackamas River. On March 17, 2011, the FERC issued an Order on Rehearing that increased the license period to forty-five years.

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	311-01 Boardman	101,073	40.00	-10.00	11.01	Life Span - 2020	9.08
13	311-01 Colstrip	88,211	56.00	-7.00	3.37	Life Span - 2042	29.72
14	311-02 Colstrip	39	56.00	-7.00	3.37	Life Span - 2042	29.72
15	311-05 Colstrip	26,692	56.00	-7.00	3.37	Life Span - 2042	29.64
16	312-00 Boardman	219,351	40.00	-10.00	11.01	Life Span - 2020	9.08
17	312-00 Colstrip	145,319	56.00	-7.00	3.40	Life Span - 2042	29.42
18	312-01 Boardman	9,758	40.00	-10.00	11.01	Life Span - 2020	9.08
19	312-05 Colstrip	70,013	56.00	-7.00	3.46	Life Span - 2042	28.94
20	314-00 Boardman	89,248	40.00	-10.00	11.01	Life Span - 2020	9.08
21	314-00 Colstrip	76,763	56.00	-7.00	3.59	Life Span - 2042	27.89
22	315-00 Boardman	23,564	40.00	-10.00	11.01	Life Span - 2020	9.08
23	315-00 Colstrip	23,576	56.00	-7.00	3.84	Life Span - 2042	26.03
24	316-01 Boardman	5,803	40.00	-10.00	11.01	Life Span - 2020	9.08
25	316-01 Colstrip	6,345	56.00	-7.00	4.15	Life Span - 2042	24.13
26	317-00 Boardman ARO	25,189				SQ	
27	317-00 Colstrip ARO	-285				SQ	
28	SUBTOTAL - STEAM	910,659					
29	330-11 Round Butte	2,212	75.00		3.13	SQ	32.00
30	331-01 Faraday	3,094	95.00	-78.00	1.68	S3	59.67
31	331-01 North Fork	1,190	95.00	-254.00	2.17	S3	46.04
32	331-01 Oak Grove	2,396	95.00	-69.00	2.01	S3	49.70
33	331-01 OG Timothy Lake	1,435	95.00	-69.00	1.34	S3	74.57
34	331-01 Pelton	2,498	95.00	-146.00	2.00	S3	50.00
35	331-01 River Mill	1,406	95.00	-155.00	1.95	S3	51.41
36	331-01 Round Butte	5,146	95.00	-61.00	1.65	S3	60.75
37	331-01 Sullivan	2,298	95.00	-36.00	1.59	S3	63.05
38	331-02 North Fork	118	95.00	-254.00	1.30	S3	76.69
39	331-02 Pelton	9	95.00	-146.00	1.33	S3	75.08
40	331-02 Round Butte	883	95.00	-61.00	1.99	S3	50.30
41	331-02 Sullivan	6,635	95.00	-36.00	1.19	S3	84.32
42	331-03 Faraday	39	95.00	-78.00	1.25	S3	80.06
43	331-03 North Fork	2,457	95.00	-254.00	1.52	S3	65.83
44	331-03 Oak Grove	1,383	95.00	-69.00	1.66	S3	60.39
45	331-03 Oak Grove Unl	1	95.00	-69.00	1.66	S3	60.39
46	331-03 Pelton	2,963	95.00	-146.00	1.41	S3	70.72
47	331-03 River Mill	1,028	95.00	-155.00	1.22	S3	81.97
48	331-03 Round Butte	1,893	95.00	-61.00	1.25	S3	80.32
49	331-03 Sullivan	5	95.00	-36.00	1.25	S3	80.06
50	331-04 Faraday	315	95.00	-78.00	1.23	S3	81.10

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	331-04 North Fork	11	95.00	-254.00	1.25	S3	80.06
13	331-04 Oak Grove	47	95.00	-69.00	1.24	S3	80.71
14	331-04 Pelton	55	95.00	-146.00	1.22	S3	81.90
15	331-04 River Mill	184	95.00	-155.00	1.21	S3	82.92
16	331-04 Round Butte	103	95.00	-61.00	1.23	S3	81.43
17	331-04 Sullivan	372	95.00	-36.00	1.21	S3	82.37
18	331-05 Faraday	11	95.00	-78.00	1.21	S3	82.64
19	331-05 Oak Grove	21	95.00	-69.00	1.22	S3	82.10
20	332-01 Faraday	17,973	100.00	-78.00	1.67	S2	59.84
21	332-01 North Fork	12,563	100.00	-254.00	1.83	S2	54.73
22	332-01 Oak Grove	14,663	100.00	-69.00	1.83	S2	54.64
23	332-01 OG Timothy Lake	4,699	100.00	-69.00	2.16	S2	46.27
24	332-01 Pelton	6,345	100.00	-146.00	2.16	S2	46.40
25	332-01 River Mill	16,110	100.00	-155.00	1.36	S2	73.69
26	332-01 Round Butte	24,461	100.00	-61.00	2.01	S2	49.80
27	332-01 Sullivan	5,605	100.00	-36.00	1.47	S2	68.21
28	332-02 Faraday	417	100.00	-78.00	1.30	S2	76.98
29	332-02 North Fork	9,528	100.00	-254.00	1.81	S2	55.25
30	332-02 Pelton	3,371	100.00	-146.00	2.08	S2	48.01
31	332-02 River Mill	21,100	100.00	-155.00	1.19	S2	84.32
32	332-02 Round Butte	2,883	100.00	-61.00	1.43	S2	69.88
33	332-02 Sullivan	17,403	100.00	-36.00	1.26	S2	79.62
34	332-02 RB Sel Water	76,201	100.00	-61.00	1.14	S2	87.64
35	332-03 North Fork	19	100.00	-254.00	1.17	S2	85.62
36	332-03 Sullivan	9	100.00	-36.00	1.18	S2	84.60
37	332-04 North Fork	90	100.00	-254.00	1.24	S2	80.65
38	332-04 Oak grove	22	100.00	-69.00	1.24	S2	80.65
39	333-00 Faraday	5,826	61.00	-78.00	2.47	S4	40.45
40	333-00 North Fork	6,745	61.00	-254.00	3.28	S4	30.48
41	333-00 Oak Grove	6,439	61.00	-69.00	2.28	S4	43.92
42	333-00 Pelton	3,965	61.00	-146.00	4.68	S4	21.38
43	333-00 River Mill	3,634	61.00	-155.00	2.66	S4	37.64
44	333-00 Round Butte	11,107	61.00	-61.00	2.90	S4	34.44
45	333-00 Sullivan	9,114	61.00	-36.00	2.30	S4	43.48
46	334-00 Faraday	2,182	47.00	-78.00	3.57	R5	28.00
47	334-00 North Fork	835	47.00	-254.00	3.71	R5	26.99
48	334-00 Oak Grove	2,375	47.00	-69.00	3.06	R5	32.68
49	334-00 Pelton	1,804	47.00	-146.00	3.38	R5	29.56
50	334-00 River Mill	2,530	47.00	-155.00	3.33	R5	30.08

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	334-00 Round Butte	2,032	47.00	-61.00	2.95	R5	33.89
13	334-00 Sullivan	4,271	47.00	-36.00	2.48	R5	40.27
14	335-01 Faraday	228	65.00	-78.00	3.03	R1	32.96
15	335-01 North Fork	190	65.00	-254.00	3.28	R1	30.48
16	335-01 Oak Grove	90	65.00	-69.00	2.74	R1	36.47
17	335-01 OG Timothy Lake	3	65.00	-69.00	3.08	R1	32.43
18	335-01 Pelton	181	65.00	-146.00	3.33	R1	30.06
19	335-01 River Mill	15	65.00	-155.00	2.46	R1	40.68
20	335-01 Round Butte	729	65.00	-61.00	2.82	R1	35.50
21	335-01 Sullivan	15	65.00	-36.00	2.56	R1	39.11
22	335-02 North Fork	247	65.00	-254.00	2.47	R1	40.54
23	335-02 Round Butte	36	65.00	-61.00	2.55	R1	39.20
24	335-02 Sullivan	94	65.00	-36.00	2.55	R1	39.18
25	335-03 North Fork	19	65.00	-254.00	2.71	R1	36.86
26	335-03 Round Butte	4	65.00	-61.00	2.46	R1	40.72
27	336-00 Faraday	1,957	75.00	-78.00	1.83	R4	54.67
28	336-00 North Fork	1,652	75.00	-254.00	2.34	R4	42.68
29	336-00 Oak Grove	2,185	75.00	-69.00	5.21	R4	19.18
30	336-00 OG Timothy Lake	107	75.00	-69.00	5.21	R4	19.18
31	336-00 Pelton	2,150	75.00	-146.00	1.82	R4	54.82
32	336-00 River Mill	458	75.00	-155.00	2.28	R4	43.86
33	336-00 Round Butte	903	75.00	-61.00	3.20	R4	31.23
34	337-00 Hydro ARO	4				SQ	
35	SUBTOTAL HYDRO	347,796					
36	341-00 Beaver	28,681	55.00	-5.00	5.34	Life Span - 2030	18.73
37	341-00 Biglow	32,704	27.00	-4.00	4.67	R3	21.41
38	341-00 Coyote Springs	10,353	45.00	-3.00	3.56	Life Span - 2040	28.11
39	341-00 Port Westward	38,926	43.00	-3.00	2.73	Life Span - 2050	36.63
40	341-02 Beaver	1,377	55.00	-5.00	5.25	Life Span - 2030	19.07
41	341-02 Coyote Springs	419	45.00	-3.00	3.55	Life Span - 2040	28.21
42	341-02 Port Westward	1,451	43.00	-3.00	2.73	Life Span - 2050	36.63
43	341-03 Beaver	176	55.00	-5.00	5.24	Life Span - 2030	19.07
44	341-03 Coyote Springs	17	45.00	-3.00	3.54	Life Span - 2040	28.25
45	341-03 Port Westward	440	43.00	-3.00	2.73	Life Span - 2050	36.63
46	342-00 Beaver	14,858	55.00	-5.00	11.00	Life Span - 2030	9.09
47	342-00 Beaver 8	1	55.00	-5.00	11.00	Life Span - 2030	9.09
48	342-00 Coyote Springs	2,815	45.00	-3.00	4.20	Life Span - 2040	23.83
49	342-00 KB Pipeline	18,976	55.00	-5.00	6.10	Life Span - 2030	16.38
50	342-00 Port Westward	9,234	43.00	-3.00	3.10	Life Span - 2050	32.28

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	342-11 Beaver	36,082	55.00	-5.00	9.68	Life Span - 2030	10.33
13	342-11 Coyote Springs	33,120	45.00	-3.00	4.70	Life Span - 2040	21.26
14	342-11 Port Westward	148	43.00	-3.00	3.10	Life Span - 2050	32.28
15	344-00 Beaver	70,689	55.00	-5.00	5.53	Life Span - 2030	18.10
16	344-00 Beaver 8	3,829	55.00	-5.00	5.53	Life Span - 2030	18.10
17	344-00 Biglow	860,383	27.00	-4.00	4.55	R3	21.98
18	344-00 Coyote Springs	98,289	45.00	-3.00	4.95	Life Span - 2040	20.19
19	344-00 Port Westward	187,491	43.00	-3.00	3.23	Life Span - 2050	30.97
20	344-11 Beaver	20,326	55.00	-5.00	7.93	Life Span - 2030	12.61
21	344-11 Coyote Springs	39,024	45.00	-3.00	5.05	Life Span - 2040	19.81
22	345-00 Beaver	6,692	55.00	-5.00	5.41	Life Span - 2030	18.47
23	345-00 Beaver 8	76	55.00	-5.00	5.41	Life Span - 2030	18.47
24	345-00 Biglow	23,972	27.00	-4.00	4.63	R3	21.62
25	345-00 Coyote Springs	11,471	45.00	-3.00	3.66	Life Span - 2040	27.35
26	345-00 Dispatch Gen	5,173	20.00	-3.00	7.20	R3	13.89
27	345-00 Port Westward	8,909	43.00	-4.00	2.87	Life Span - 2050	34.88
28	345-11 Beaver	6,217	55.00	-5.00	5.43	Life Span - 2030	18.41
29	346-00 Beaver	3,448	55.00	-5.00	6.40	Life Span - 2030	15.63
30	346-00 Biglow	552	27.00	-4.00	4.89	R3	20.47
31	346-00 Coyote Springs	2,061	45.00	-3.00	4.03	Life Span - 2040	24.80
32	346-00 KB Pipeline	73	55.00	-5.00	5.74	Life Span - 2030	17.42
33	346-00 Port Westward	2,968	43.00	-4.00	2.99	Life Span - 2050	33.44
34	347-00 Beaver ARO	42				SQ	
35	347-00 Biglow ARO	1,833				SQ	
36	347-00 Coy Sprgs ARO	113				SQ	
37	347-00 Port West ARO	226				SQ	
38	SUBTOTAL OTHER	1,583,635					
39	352-00 Struct & Impr	11,500	52.00	-10.00	3.37	S6	29.66
40	352-00 Beaver 8	2	52.00	-10.00	3.37	S6	29.66
41	352-00 Biglow	903	52.00	-10.00	2.08	S6	48.19
42	352-00 Colstrip	778	52.00	-10.00	3.82	S6	26.17
43	352-00 Faraday	410	52.00	-10.00	4.59	S6	21.77
44	352-00 Port Westward	317	52.00	-10.00	2.08	S6	48.19
45	352-00 Round Butte	134	52.00	-10.00	9.29	S6	10.76
46	352-01 Struct & Impr	2,323	52.00	-10.00	2.34	S6	42.70
47	353-00 Sta Equip - Oth	114,241	50.00	-8.00	3.24	R2	30.90
48	353-00 Beaver 8	119	50.00	-8.00	3.24	R2	30.90
49	353-00 Beaver	6,058	50.00	-8.00	4.14	R2	24.15
50	353-00 Bethel	45	50.00	-8.00	2.83	R2	35.39

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	353-00 Biglow	22,281	50.00	-8.00	2.89	R2	34.58
13	353-00 Boardman	5,908	40.00	-10.00	11.01	Life span - 2020	9.08
14	353-00 Bull Run	5	50.00	-8.00	3.24	R2	30.90
15	353-00 Colstrip	17,962	50.00	-8.00	3.99	R2	25.08
16	353-00 Coyote Springs	12,528	50.00	-8.00	3.28	R2	30.47
17	353-00 Faraday	4,732	50.00	-8.00	3.74	R2	26.74
18	353-00 North Fork	651	50.00	-8.00	7.10	R2	14.09
19	353-00 Oak Grove	3,457	50.00	-8.00	3.11	R2	32.14
20	353-00 Pelton	894	50.00	-8.00	3.34	R2	29.96
21	353-00 Port Westward	15,327	50.00	-8.00	2.83	R2	35.39
22	353-00 River Mill	1,693	50.00	-8.00	3.33	R2	30.04
23	353-00 Round Butte	2,842	50.00	-8.00	3.39	R2	29.50
24	353-00 Round Butte Unl	5,759	50.00	-8.00	3.20	R2	31.25
25	353-00 RB Switchyard	2,842	50.00	-8.00	3.20	R2	31.25
26	353-00 Sullivan	1,649	50.00	-8.00	2.85	R2	35.09
27	353-00 Sullivan Unl	29	50.00	-8.00	4.43	R2	22.57
28	354-00 Towers - Other	17,383	75.00	-15.00	2.85	R3	35.09
29	354-00 Boardman	3,066	40.00	-10.00	11.01	Life span - 2020	9.08
30	354-00 Colstrip	22,839	75.00	-15.00	2.25	R3	44.37
31	354-00 Coyote Springs	1,812	75.00	-15.00	1.91	R3	52.44
32	354-00 Oak Grove	180	75.00	-15.00	5.62	R3	17.78
33	354-00 Pelton	19	75.00	-15.00	3.83	R3	26.11
34	354-00 Round Butte	1,507	75.00	-15.00	3.44	R3	29.09
35	355-00 Poles - Other	16,579	56.00	-85.00	3.62	L0	27.65
36	355-00 Boardman	213	40.00	-10.00	11.01	Life span - 2020	9.08
37	355-00 Colstrip	110	56.00	-85.00	3.33	L0	30.01
38	355-00 North Fork	251	56.00	-85.00	3.34	L0	29.92
39	355-00 Oak Grove	361	56.00	-85.00	3.35	L0	29.82
40	355-00 Pelton	184	56.00	-85.00	3.71	L0	26.93
41	355-00 Round Butte	1,120	56.00	-85.00	3.55	L0	28.20
42	356-00 Ovhd Wire - Oth	51,517	53.00	-45.00	3.29	R3	30.41
43	356-00 Boardman	2,315	40.00	-10.00	11.01	Life span - 2020	9.08
44	356-00 Colstrip	19,863	53.00	-45.00	3.91	R3	25.58
45	356-00 Coyote Springs	1,812	53.00	-45.00	2.99	R3	33.49
46	356-00 North Fork	370	53.00	-45.00	3.50	R3	28.57
47	356-00 Oak Grove	859	53.00	-45.00	8.28	R3	12.08
48	356-00 Pelton	97	53.00	-45.00	10.57	R3	9.46
49	356-00 Round Butte	3,050	53.00	-45.00	8.04	R3	12.44
50	359-00 Colstrip	286	60.00		3.17	R4	31.55

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	359-10 Trans ARO	53				SQ	
13	SUBTOTAL	381,235					
14	361-00 Struct & Impr	27,908	53.00	-20.00	3.33	R1.5	30.00
15	361-01 Struct & Impr	7,961	53.00	-20.00	2.89	R1.5	34.55
16	362-00 Sta Equp - Oth	348,817	60.00	-15.00	3.24	L0	30.88
17	362-00 Bethel	68	60.00	-15.00	3.24	L0	30.88
18	362-00 Harborton	1,600	60.00	-15.00	3.16	L0	31.70
19	362-00 Sullivan	4,004	60.00	-15.00	3.16	L0	31.70
20	362-00 Summit	1,037	60.00	-15.00	3.16	L0	31.63
21	364-00 Poles, Towers	308,052	41.00	-65.00	4.74	L0	21.11
22	365-00 Overhead Wire	513,088	37.00	-80.00	4.65	L2	21.49
23	366-00 Undrgrd Conduit	15,611	60.00	-15.00	3.06	S6	32.70
24	367-00 Undrgrd Wire	606,755	40.00	-70.00	3.91	S2	25.60
25	368-00 Line Transformr	293,659	39.00	-15.00	4.55	R2.5	21.97
26	369-01 Services Ovrhd	33,767	50.00	-63.00	4.68	R3	21.38
27	369-03 Services Undrgd	333,891	50.00	-63.00	3.24	R3	30.85
28	370-00 Meters - Other	1,308	18.00		11.55	R3	8.66
29	370-01 AMI Meters	114,039	18.00		6.81	R3	14.68
30	370-02 Retained Meters	7,602	18.00		11.55	R3	8.66
31	371-00 Eq on Cust Prem	376	20.00		10.53	R2	9.50
32	373-01 Circuits	20,988	37.00	-70.00	4.75	L2	21.05
33	373-02 Fixtures	27,488	24.00	-48.00	8.16	L0	12.25
34	373-07 Sentinel Lights	8,551	22.00	-70.00	9.94	L0	10.06
35	374-00 Dist ARO	460				SQ	
36	SUBTOTAL DIST	2,677,030					
37	390-00 Struct - Other	46,616	33.00		5.79	R0.5	17.29
38	390-00 World Trade Ctr	16,914	33.00		5.84	R0.5	17.13
39	390-01 Equipment	921	33.00		5.79	R0.5	17.29
40	390-02 Land Improvmnt	1,138	33.00		5.79	R0.5	17.29
41	390-03 Info Systems	1,687	33.00		5.79	R0.5	17.29
42	391-00 Off Furn - Oth	13,854	16.00		11.01	SQ	9.08
43	391-00 Boardman	165	16.00	-10.00	11.01	Life span - 2020	9.08
44	391-02 Computers - Oth	46,583	5.00		33.33	SQ	3.00
45	391-02 Boardman	198	5.00	-10.00	11.01	Life span - 2020	9.08
46	391-02 Round Butte	30	5.00		33.33	SQ	3.00
47	392-04 Hvy Duty Trucks	9,271	15.00	10.00	18.22	R3	5.49
48	392-04 Boardman	719	15.00	-10.00	11.01	Life span - 2020	9.08
49	392-04 Colstrip	81	15.00	10.00	18.22	R3	5.49
50	392-04 Round Butte	197	15.00	10.00	16.62	R3	6.02

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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	392-05 Med Duty Trucks	11,959	12.00	10.00	19.34	S3	5.17
13	392-05 Boardman	325	12.00	-10.00	11.01	Life span - 2020	9.08
14	392-05 Colstrip	28	12.00	10.00	19.34	S3	5.17
15	392-05 Round Butte	523	12.00	10.00	16.95	S3	5.90
16	392-06 Lgt Duty Trucks	8,611	10.00	10.00	20.49	S6	4.88
17	392-06 Boardman	112	10.00	-10.00	11.01	Life span - 2020	9.08
18	392-06 Colstrip	134	10.00	10.00	20.49	S6	4.88
19	392-06 Round Butte	177	10.00	10.00	20.71	S6	4.83
20	392-08 Trailers	4,686	20.00	10.00	12.47	S6	8.02
21	392-08 Boardman	34	20.00	-10.00	11.01	Life span - 2020	9.08
22	392-08 Colstrip	14	20.00	10.00	12.47	S6	8.02
23	392-08 Round Butte	39	20.00	10.00	7.02	S6	14.26
24	392-09 Automobiles	1,133	10.00	10.00	15.98	S6	6.26
25	392-09 Boardman	12	10.00	-10.00	11.01	Life span - 2020	9.08
26	392-09 Colstrip	3	10.00	10.00	15.98	S6	6.26
27	392-10 Helicopter	2,703	20.00	15.00	5.62	SQ	17.79
28	393-00 Stores Equip	320	22.00		13.33	SQ	7.50
29	393-00 Port Westward	89	22.00		5.41	SQ	18.50
30	393-01 Forklifts	1,967	22.00		13.33	SQ	7.50
31	393-01 Boardman	102	22.00	-10.00	11.01	Life span - 2020	9.08
32	393-01 Round Butte	25	22.00		13.33	SQ	7.50
33	394-00 Tools & Shop Eq	10,522	20.00	5.00	12.50	SQ	8.00
34	394-00 Port Westward	115	20.00	5.00	6.06	SQ	16.50
35	395-00 Lab Equipment	10,264	18.00		12.16	SQ	8.23
36	395-00 Boardman	250	18.00	-10.00	11.01	Life span - 2020	9.08
37	396-01 Man Lift Equip	25,285	15.00	10.00	13.13	L2	7.62
38	396-02 Digger Equip	7,139	15.00	10.00	13.58	L2	7.37
39	396-02 Boardman	810	15.00	-10.00	11.01	Life span - 2020	9.08
40	396-03 Crane	4,575	15.00	10.00	12.89	L2	7.76
41	396-03 Boardman	349	15.00	-10.00	11.01	Life span - 2020	9.08
42	396-03 Colstrip	47	15.00	10.00	12.89	L2	7.76
43	396-03 Round Butte	106	15.00	10.00	22.83	L2	4.38
44	396-07 Costruct Equ	3,729	15.00	10.00	14.53	L2	6.88
45	396-07 Boardman	1,048	15.00	-10.00	11.01	Life span - 2020	9.08
46	396-07 Colstrip	102	15.00	10.00	14.53	L2	6.88
47	396-07 Round Butte	625	15.00	10.00	12.58	L2	7.95
48	397-01 Line Equip	1,637	50.00		4.05	L0	24.70
49	397-01 Faraday	9	50.00		3.71	L0	26.94
50	397-01 North Fork	94	50.00		3.86	L0	25.93

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	397-01 Timothy Lake	22	50.00		3.74	L0	26.72
13	397-01 Oak Grove	45	50.00		4.18	L0	23.94
14	397-01 River Mill	15	50.00		3.98	L0	25.14
15	397-01 Round Butte	51	50.00		4.21	L0	23.75
16	397-03 Radio Equip	57,517	24.00		8.53	L2	11.72
17	397-03 Beaver 8	6	24.00		7.24	L2	13.80
18	397-03 Beaver	865	24.00		8.89	L2	11.25
19	397-03 Biglow	601	24.00		6.19	L2	16.17
20	397-03 Boardman	453	24.00	-10.00	11.01	Life span - 2020	9.08
21	397-03 Colstrip	3,173	24.00		10.99	L2	9.10
22	397-03 Coyote Springs	156	24.00		8.34	L2	11.99
23	397-03 Faraday	259	24.00		9.75	L2	10.26
24	397-03 Harborton	461	24.00		9.90	L2	10.10
25	397-03 North Fork	16	24.00		27.90	L2	3.58
26	397-03 Timothy Lake	500	24.00		13.38	L2	7.47
27	397-03 Oak Grove	246	24.00		10.83	L2	9.23
28	397-03 Pelton	370	24.00		9.45	L2	10.58
29	397-03 Pelton Unl	12	24.00		11.69	L2	8.55
30	397-03 Port Westward	1,867	24.00		6.27	L2	15.94
31	397-03 River MIll	16	24.00		11.78	L2	8.49
32	397-03 Round Butte	1,252	24.00		8.92	L2	11.21
33	397-03 Round Butte Unl	309	24.00		6.62	L2	15.10
34	397-03 Sullivan	205	24.00		8.89	L2	11.24
35	397-03 Summit	36	24.00		8.56	L2	11.68
36	397-06 Mobile Radio	731	5.00		33.33	SQ	3.00
37	397-07 Telephone Equ	682	10.00		33.33	SQ	3.00
38	398-00 Misc Equip	132	16.00		25.28	SQ	3.96
39	399.10 General ARO	64				SQ	
40	SUBTOTAL GEN PLANT	308,138					
41							
42	Plant balances are						
43	YE 2011 original cost						
44							
45	Applied depreciation						
46	rates for all assets						
47	excluding Boardman,						
48	effective 1/1/2011 per						
49	Order 10-355 in OPUC						
50	Docket UM-1458						

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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	and Order 10-478 in						
13	PGE's UE-215 general						
14	rate case.						
15							
16	Applied depreciation						
17	rates for Boardman						
18	assets assume a						
19	terminal retirement						
20	of 12/31/2020,						
21	became effective						
22	7/01/2011, per						
23	Order 11-242 in						
24	PGE's Advice Filing						
25	No. 11-07.						
26							
27							
28							
29							
30							
31							
32							
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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-California Refund		32,861	32,861	
2	Docket No. EL00-95				
3					
4	FERC-NERC Reliability		212,386	212,386	
5	Docket No. RM06-22				
6					
7	OPUC-2012 Annual Power Cost Update Tariff		244,658	244,658	
8	Docket No. UE-228				
9					
10	OPUC-URP Income Tax OPUC Deferral Request		50,086	50,086	
11	Docket No. UM1224				
12					
13	OPUC-RFP for Capacity & Baseload		28,981	28,981	
14	Energy Resources				
15	Docket No. UM-1535				
16					
17	BPA-BPA Wholesale Power Rate Case		30,787	30,787	
18	Appeal-Non Rate				
19	Docket No. WPA-10				
20					
21	FERC matters less than $25,000		66,074	66,074	
22					
23	OPUC matters less than $25,000		234,449	234,449	
24					
25	Non Docs matters less than $25,000		421,087	421,087	
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL		1,321,369	1,321,369	

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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	32,861					1
							2
							3
	928	212,386					4
							5
							6
	928	244,658					7
							8
							9
	928	50,086					10
							11
							12
	928	28,981					13
							14
							15
							16
	928	30,787					17
							18
							19
							20
	928	66,074					21
							22
	928	234,449					23
							24
	928	421,087					25
							26
							27
							28
							29
							30
							31
							32
							33
							34
							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		1,321,369					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 2011/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)(e)	Unconventional Generation
4		
5	A(3)	Electric R, D & D Performed Internally - Distribution
6		
7	B(1)	Electric R, D & D Performed Externally
8		Research Support to the Electrical Research Council or EPRI
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25	Totals	
26		
27		
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36		
37		
38		

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RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

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

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

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
7,613		930.2	7,613		2
383,424		930.2	383,424		3
					4
252,347		930.2	252,347		5
					6
					7
	204,214	930.2	204,214		8
					9
					10
					11
					12
					13
					14
					15
					16
					17
					18
					19
					20
					21
					22
					23
					24
643,384	204,214		847,598		25
					26
					27
					28
					29
					30
					31
					32
					33
					34
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					36
					37
					38

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DISTRIBUTION OF SALARIES AND WAGES

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

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	25,743,630		
4	Transmission	3,494,846		
5	Regional Market			
6	Distribution	19,320,192		
7	Customer Accounts	26,675,101		
8	Customer Service and Informational	6,023,571		
9	Sales			
10	Administrative and General	45,108,927		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	126,366,267		
12	Maintenance			
13	Production	10,213,581		
14	Transmission	1,580,049		
15	Regional Market			
16	Distribution	21,426,123		
17	Administrative and General	647,471		
18	TOTAL Maintenance (Total of lines 13 thru 17)	33,867,224		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	35,957,211		
21	Transmission (Enter Total of lines 4 and 14)	5,074,895		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	40,746,315		
24	Customer Accounts (Transcribe from line 7)	26,675,101		
25	Customer Service and Informational (Transcribe from line 8)	6,023,571		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	45,756,398		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	160,233,491	4,722,268	164,955,759
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			

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DISTRIBUTION OF SALARIES AND WAGES (Continued)

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Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	160,233,491	4,722,268	164,955,759
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	59,446,452	3,537,355	62,983,807
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	59,446,452	3,537,355	62,983,807
72	Plant Removal (By Utility Departments)			
73	Electric Plant	1,692,052	3,466	1,695,518
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	1,692,052	3,466	1,695,518
77	Other Accounts (Specify, provide details in footnote):			
78	Other Income and Deductions	1,846,065	73,068	1,919,133
79	Co-owner Shares of Generating Facilities	8,500,545	223,989	8,724,534
80	Other	3,871,389	57,909	3,929,298
81	Payroll Allocated	8,618,055	-8,618,055	
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	22,836,054	-8,263,089	14,572,965
96	TOTAL SALARIES AND WAGES	244,208,049		244,208,049

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.

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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)	438,134	143,802	144,546	758,984
3	Net Sales (Account 447)	2,031,119	2,560,066	2,936,343	10,175,021
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8					
9					
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44					
45					
46	TOTAL	2,469,253	2,703,868	3,080,889	10,934,005

PURCHASES AND SALES OF ANCILLARY SERVICES

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

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

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

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

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

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

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

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

Line No.	Type of Ancillary Service (a)	Amount Purchased for the Year — Usage - Related Billing Determinant: Number of Units (b)	Unit of Measure (c)	Dollars (d)	Amount Sold for the Year — Usage - Related Billing Determinant: Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	46,284	MW	15,318,252	5,045,541	Various	114,976
2	Reactive Supply and Voltage		MW		1,723,994	Various	56,556
3	Regulation and Frequency Response				1,723,994	Various	131,637
4	Energy Imbalance	12,308	MW-Hour	371,810	15,048	MW-Hour	264,760
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other						
8	Total (Lines 1 thru 7)	58,592		15,690,062	8,508,577		567,929

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

Scheduling, System Control and Dispatch			
No of Units	Unit of Measure		Amount
137,723	MW Day	$	11,197
355,270	MW Hour		6,758
326,372	MW Month		9,867
8,625	MW Week		216
2,493,683	MW Year		69,699
1,723,868	Sum of Peak Demand (KW)		17,239
5,045,541	Total	$	114,976

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

None in 2011

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

None in 2011

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

Scheduling, System Control and Dispatch			
No of Units	Unit of Measure		Amount
126	MW Month	$	4,840
1,723,868	Sum of Peak Demand (KW)		51,716
1,723,994	Total	$	56,556

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

Scheduling, System Control and Dispatch			
No of Units	Unit of Measure		Amount
126	MW Month	$	10,966
1,723,868	Sum of Peak Demand (KW)		120,671
1,723,994	Total	$	131,637

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

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

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

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

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

Total is not meaningful because it represents a summation of amounts of dissimilar units of measure.

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

Total is not meaningful because it represents a 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 2011/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	4,315	11	1900	3,405	163	665	13	4,007	25
2	February	4,188	2	800	3,138	144	665	13	4,307	
3	March	3,674	4	800	2,792	133	665	13	4,307	151
4	Total for Quarter 1	12,177			9,335	440	1,995	39	12,621	176
5	April	3,559	1	2399	2,399	121	665	13	4,307	100
6	May	3,507	23	2327	2,327	135	665	13	4,157	
7	June	3,379	21	2506	2,506	146	665	13	4,157	20
8	Total for Quarter 2	10,445			7,232	402	1,995	39	12,621	120
9	July	3,666	6	2850	2,850	150	665	13	4,157	75
10	August	4,023	25	3169	3,169	154	665	13	4,254	188
11	September	4,099	8	3110	3,110	155	665	13	4,254	165
12	Total for Quarter 3	11,788			9,129	459	1,995	39	12,665	428
13	October	3,553	28	1900	2,500	127	665	13	4,254	29
14	November	3,932	15	1900	2,905	133	665	13	4,504	
15	December	4,238	15	1900	3,101	10	665	13	4,350	258
16	Total for Quarter 4	11,723			8,506	270	1,995	39	13,108	287
17	Total Year to Date/Year	46,133			34,202	1,571	7,980	156	51,015	1,011

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	288	21	900			307			
2	February	282	19	1600			307			
3	March	290	11	1800			307			
4	Total for Quarter 1	860					921			
5	April	231	25	2200			307			
6	May	184	4	1300			307			
7	June	272	28	2200			307			
8	Total for Quarter 2	687					921			
9	July	278	1	2000			307			
10	August	269	30	1000			307			
11	September	283	14	1000			307			
12	Total for Quarter 3	830					921			
13	October	295	12	2400			307			
14	November	291	13	2300			307			
15	December	292	5	300			307			
16	Total for Quarter 4	878					921			
17	Total Year to Date/Year	3,255					3,684			

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

Long Term Firm Point-to-Point Reservation:

Reservation #	Customer	January Capacity	February Capacity	March Capacity	Earliest Termination Date
432190	Portland General Electric	200	200	200	01/01/2012
71472976	Shell Energy NA	200	200	200	01/01/2022
71324505	Powerex	165	165	165	06/01/2013
71324658	Avista Water and Power	100	100	100	01/01/2013
	Total	665	665	665	

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

Other Long Term Service:

	Customer	Capacity	Earliest Termination Date
Grandfathered	SEMPRA (San Diego Gas & Electric)	13	12/31/2020

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	January Capacity	February Capacity	March Capacity
74687802	Portland General Electric Co.	300	300	300
75029658	Portland General Electric Co.	25	25	25
75029672	Portland General Electric Co.	200	200	200
75029675	Portland General Electric Co.	2	2	2
75029864	Portland General Electric Co.	480	480	480
75029861	Portland General Electric Co.	3,000		
75175099	Portland General Electric Co.		3,300	
75336019	Portland General Electric Co.			3,300
	Total	4,007	4,307	4,307

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

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

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

Long Term Firm Point-to-Point Reservation:

Reservation #	Customer	April Capacity	May Capacity	June Capacity	Earliest Termination Date
432190	Portland General Electric	200	200	200	01/01/2012
315999	Avista Corporation	200	200	200	01/01/2022
71324505	Powerex	165	165	165	06/01/2013
71324658	Avista Water and Power	100	100	100	01/01/2013
	Total	665	665	665	

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

Other Long Term Service:

	Customer	Capacity	Earliest Termination Date
Grandfathered	SEMPRA (San Diego Gas & Electric)	13	12/31/2020

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	April Capacity	May Capacity	June Capacity
74687802	Portland General Electric Co.	300		
75029658	Portland General Electric Co.	25	25	25
75029672	Portland General Electric Co.	200	200	200
75029675	Portland General Electric Co.	2	2	2
75029864	Portland General Electric Co.	480	480	480
75460668	Portland General Electric Co.	3,300		
75587868	Portland General Electric Co.		3,300	
75605841	Portland General Electric Co.		150	
75706256	Portland General Electric Co.			3,300
75706263	Portland General Electric Co.			150
	Total	4,307	4,157	4,157

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

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

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

Long Term Firm Point-to-Point Reservation:

Reservation #	Customer	July Capacity	August Capacity	September Capacity	Earliest Termination Date
432190	Portland General Electric	200	200	200	01/01/2012
315999	Avista Corporation	200	200	200	01/01/2022
71324505	Powerex	165	165	165	06/01/2013
71324658	Avista Water and Power	100	100	100	01/01/2013
	Total	665	665	665	

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

Other Long Term Service:

	Customer	Capacity	Earliest Termination Date
Grandfathered	SEMPRA (San Diego Gas & Electric)	13	12/31/2020

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	July Capacity	August Capacity	September Capacity
75029658	Portland General Electric Co.	25	25	25
75029672	Portland General Electric Co.	200	200	200
75029675	Portland General Electric Co.	2	2	2
75029864	Portland General Electric Co.	480	480	480
75706263	Portland General Electric Co.	150	150	150
75831556	Portland General Electric Co.	3,300		
75981996	Portland General Electric Co.		3,030	
75966501	Powerex		97	97
75973007	Portland General Electric Co.		270	
76092974	Portland General Electric Co.			3,300
	Total	4,157	4,254	4,254

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

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

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

Long Term Firm Point-to-Point Reservation:

Reservation #	Customer	October Capacity	November Capacity	December Capacity	Earliest Termination Date
432190	Portland General Electric	200	200	200	01/01/2012
71472976	Shell Energy NA	200	200	200	01/01/2022
71324505	Powerex	165	165	165	06/01/2013
71324658	Avista Water and Power	100	100	100	01/01/2013
	Total	665	665	665	

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

Other Long Term Service:

	Customer	Capacity	Earliest Termination Date
Grandfathered	SEMPRA (San Diego Gas & Electric)	13	12/31/2020

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	October Capacity	November Capacity	December Capacity
75029658	Portland General Electric Co.	25	25	25
75029672	Portland General Electric Co.	200	200	200
75029675	Portland General Electric Co.	2	2	2
75029864	Portland General Electric Co.	480	480	480
75706263	Portland General Electric Co.	150	150	150
75966501	Powerex	97		
76205586	Portland General Electric Co.	3,300		
76195755	Southern California Edison		47	
76202056	Cargill Power Markets, LLC		50	
76292436	Portland General Electric Co.		3,300	
76303879	Constellation Energy		50	
76347642	Puget Sound Energy Marketing		200	
76220412	Southern California Edison			25
76295902	Constellation Energy			50
76386462	Portland General Electric Co.			3,300
76446717	Puget Sound Energy Marketing			96
76451990	Cargill Power Markets, LLC			22
	Total	4,254	4,504	4,350

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

Other Service:

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

(NONFIRM SCHEDULES)

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

Colstrip

Monthly Peak MW:

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

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

Long-Term Firm Point to Point Reservation:

Reservation #	Customer	Capacity	Earliest Termination Date
73065442	Portland General Electric	27	07/01/2022
73068563	Portland General Electric	280	07/01/2022
	Total	307	

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

Colstrip

Monthly Peak MW:

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

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

Long-Term Firm Point to Point Reservation:

Reservation #	Customer	Capacity	Earliest Termination Date
73065442	Portland General Electric	27	07/01/2022
73068563	Portland General Electric	280	07/01/2022
	Total	307	

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

Colstrip

Monthly Peak MW:

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

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

Long-Term Firm Point to Point Reservation:

Reservation #	Customer	Capacity	Earliest Termination Date
73065442	Portland General Electric	27	07/01/2022
73068563	Portland General Electric	280	07/01/2022
	Total	307	

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

Colstrip

Monthly Peak MW:

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

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

Long-Term Firm Point to Point Reservation:

Reservation #	Customer	Capacity	Earliest Termination Date
76059414	Portland General Electric	307	07/01/2022
	Total	307	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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 2011/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)	18,356,826
3	Steam	4,125,002	23	Requirements Sales for Resale (See instruction 4, page 311.)	
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	2,978,442
5	Hydro-Conventional	1,932,996	25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	24,324
7	Other	3,354,089	27	Total Energy Losses	1,075,598
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	22,435,190
9	Net Generation (Enter Total of lines 3 through 8)	9,412,087			
10	Purchases	13,027,363			
11	Power Exchanges:				
12	Received	465,054			
13	Delivered	475,214			
14	Net Exchanges (Line 12 minus line 13)	-10,160			
15	Transmission For Other (Wheeling)				
16	Received	5,391,323			
17	Delivered	5,385,423			
18	Net Transmission for Other (Line 16 minus line 17)	5,900			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	22,435,190			

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 2011/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	2,052,517	205,133	3,555	11	1900
30	February	1,924,463	269,460	3,385	25	0800
31	March	1,923,449	199,489	3,053	1	1900
32	April	1,859,874	295,271	2,929	12	0800
33	May	1,748,682	252,129	2,629	12	0800
34	June	1,773,032	346,112	2,658	21	1800
35	July	1,882,848	371,056	2,991	6	1800
36	August	1,981,511	355,408	3,316	25	1700
37	September	1,810,007	281,467	3,340	7	1800
38	October	1,701,086	188,715	2,800	26	0800
39	November	1,818,848	174,860	3,097	29	1800
40	December	1,952,973	80,035	3,418	6	1800
41	TOTAL	22,429,290	3,019,135			

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

Includes 1,215,633 megawatt hours of net wind energy as scheduled and delivered by Bonneville Power Administration from PGE's Biglow Canyon Wind Project. Actual net wind generation from the Project to Bonneville Power Administration was 1,178,173 megawatt 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 12/31/2011: $918,725,094
Total installed capacity: 450 megawatts
Operations and Maintenance expenses for 2011: $14,930,818

Schedule Page: 401   Line No.: 29   Column: c

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

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			417.43		
6	Net Peak Demand on Plant - MW (60 minutes)	598			0		
7	Plant Hours Connected to Load	6208			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	575			0		
10	When Limited by Condenser Water	575			0		
11	Average Number of Employees	112			0		
12	Net Generation, Exclusive of Plant Use - KWh	3305796000			2191433000		
13	Cost of Plant: Land and Land Rights	1274078			832853		
14	Structures and Improvements	153132849			101073073		
15	Equipment Costs	533895764			346266930		
16	Asset Retirement Costs	33978545			25189268		
17	Total Cost	722281236			473362124		
18	Cost per KW of Installed Capacity (line 17/5) Including	1124.6983			1133.9916		
19	Production Expenses: Oper, Supv, & Engr	5378605			2799461		
20	Fuel	63468760			41507187		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	2386700			2209294		
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	7176916			4662468		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	5723519			279135		
30	Maintenance of Structures	369601			285020		
31	Maintenance of Boiler (or reactor) Plant	7725			5773		
32	Maintenance of Electric Plant	10443437			10244782		
33	Maintenance of Misc Steam (or Nuclear) Plant	4573460			2485078		
34	Total Production Expenses	99528723			64478198		
35	Expenses per Net KWh	0.0301			0.0294		
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	1985277	12725	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	8517	138600	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	30.156	137.366	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	31.186	122.320	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	1.831	21.013	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	10229.700	22.400	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 2011/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			1933569000		
13	Cost of Plant: Land and Land Rights	0			3327908		
14	Structures and Improvements	0			114941832		
15	Equipment Costs	0			322016279		
16	Asset Retirement Costs	0			-285471		
17	Total Cost	0			440000548		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			1413.8835		
19	Production Expenses: Oper, Supv, & Engr	0			1223236		
20	Fuel	0			27807849		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			1450780		
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			1429672		
27	Rents	0			31254		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			2825008		
30	Maintenance of Structures	0			664756		
31	Maintenance of Boiler (or reactor) Plant	0			5198215		
32	Maintenance of Electric Plant	0			805834		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			-124940		
34	Total Production Expenses	0			41311664		
35	Expenses per Net KWh	0.0000			0.0214		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Beaver* (d)			Plant Name: *Port Westward* (e)			Plant Name: *Coyote Springs* (f)			Line No.
		Gas & Steam Turbine			Gas & Steam Turbine			Gas & Steam Turbine	1
		Outdoor			Outdoor			Outdoor	2
		1974			2007			1995	3
		2001			2007			1995	4
		610.70			483.30			266.40	5
		515			429			272	6
		371			3373			2628	7
		0			0			0	8
		533			418			270	9
		0			0			0	10
		53			22			28	11
		56399000			1391213000			690844000	12
		0			0			0	13
		30234068			40816455			10789145	14
		171705780			218238534			186779776	15
		42315			226391			112544	16
		201982163			259281380			197681465	17
		330.7388			536.4812			742.0475	18
		1475874			2266465			2458518	19
		7418924			123588927			67087088	20
		0			0			0	21
		0			0			0	22
		0			0			0	23
		0			0			0	24
		0			0			0	25
		2992211			1547903			545366	26
		179310			33929			68369	27
		0			0			0	28
		545991			25017			28125	29
		35545			7170			0	30
		0			0			0	31
		3698679			4474685			6708836	32
		64898			41508			30505	33
		16411432			131985604			76926807	34
		0.2910			0.0949			0.1114	35
Gas	Oil		Gas	Oil		Gas	Oil		36
Mcf's	Barrels		Mcf's	Barrels		Mcf's	Barrels		37
158269	32	0	10305642	0	0	5445302	158	0	38
1011000	138600	0	1011000	138600	0	1011000	138600	0	39
13.869	0.000	0.000	3.635	0.000	0.000	3.486	0.000	0.000	40
46.855	99.321	0.000	11.992	0.000	0.000	12.320	0.196	0.000	41
46.340	17.083	0.000	11.860	0.000	0.000	12.184	0.034	0.000	42
131.487	0.056	0.000	0.089	0.000	0.000	0.097	0.000	0.000	43
2837443.900	3302.800	0.000	7490.100	0.000	0.000	7969.800	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 2011/Q4

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

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
									1
									2
									3
									4
0.00			0.00			0.00			5
0			0			0			6
0			0			0			7
0			0			0			8
0			0			0			9
0			0			0			10
0			0			0			11
0			0			0			12
0			0			0			13
0			0			0			14
0			0			0			15
0			0			0			16
0			0			0			17
0			0			0			18
0			0			0			19
0			0			0			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
0			0			0			25
0			0			0			26
0			0			0			27
0			0			0			28
0			0			0			29
0			0			0			30
0			0			0			31
0			0			0			32
0			0			0			33
0			0			0			34
0.0000			0.0000			0.0000			35
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

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

Respondent is the principal owner (65% interest) and operator of the Boardman Plant. The other owners are Idaho Power Company (10% interest), Power Resources Cooperative (10% interest), and BA Leasing BSC, LLC (15% interest). Reported here are 100% costs and plant statistics, including shared and non-shared costs.

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

Jointly owned. Installed capacity on line 5 represents 65% share. Reported here are respondent's share of cost of plant, net generation and production expenses. Details are reported on Page 402, col. (b).

Schedule Page: 402 Line No.: 9 Column: d

Based on January average temperature.

Schedule Page: 402 Line No.: 9 Column: e

Based on January average temperature.

Schedule Page: 402 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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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;Semi-ou
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	48
7	Plant Hours Connect to Load	0	8,040
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	46
10	(b) Under the Most Adverse Oper Conditions	0	39
11	Average Number of Employees	0	44
12	Net Generation, Exclusive of Plant Use - Kwh	0	172,202,000
13	Cost of Plant		
14	Land and Land Rights	0	33,434
15	Structures and Improvements	0	3,460,388
16	Reservoirs, Dams, and Waterways	0	18,389,402
17	Equipment Costs	0	8,235,859
18	Roads, Railroads, and Bridges	0	1,956,781
19	Asset Retirement Costs	0	76
20	TOTAL cost (Total of 14 thru 19)	0	32,075,940
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	871.6288
22	Production Expenses		
23	Operation Supervision and Engineering	0	331,557
24	Water for Power	0	59,516
25	Hydraulic Expenses	0	443,271
26	Electric Expenses	0	177,188
27	Misc Hydraulic Power Generation Expenses	0	632,569
28	Rents	0	88
29	Maintenance Supervision and Engineering	0	156,942
30	Maintenance of Structures	0	66
31	Maintenance of Reservoirs, Dams, and Waterways	0	142,112
32	Maintenance of Electric Plant	0	155,656
33	Maintenance of Misc Hydraulic Plant	0	764,027
34	Total Production Expenses (total 23 thru 33)	0	2,862,992
35	Expenses per net KWh	0.0000	0.0166

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)	Run-of-River;Storage	Run-of-River;Storage
2	Plant Construction type (Conventional or Outdoor)	Semi-Outdoor	Semi-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	73.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	112	0
7	Plant Hours Connect to Load	7,030	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	110	0
10	(b) Under the Most Adverse Oper Conditions	108	0
11	Average Number of Employees	6	0
12	Net Generation, Exclusive of Plant Use - Kwh	478,013,000	318,691,000
13	Cost of Plant		
14	Land and Land Rights	3,672,025	2,448,139
15	Structures and Improvements	8,283,847	5,525,184
16	Reservoirs, Dams, and Waterways	14,333,049	9,718,951
17	Equipment Costs	8,949,662	5,949,799
18	Roads, Railroads, and Bridges	3,217,839	2,150,191
19	Asset Retirement Costs	0	42
20	TOTAL cost (Total of 14 thru 19)	38,456,422	25,792,306
21	Cost per KW of Installed Capacity (line 20 / 5)	350.2406	353.3193
22	Production Expenses		
23	Operation Supervision and Engineering	348,306	232,216
24	Water for Power	28,918	19,279
25	Hydraulic Expenses	500,359	333,589
26	Electric Expenses	133,223	88,820
27	Misc Hydraulic Power Generation Expenses	320,819	213,890
28	Rents	15,722	10,482
29	Maintenance Supervision and Engineering	29,639	19,760
30	Maintenance of Structures	1,287	858
31	Maintenance of Reservoirs, Dams, and Waterways	33,563	22,376
32	Maintenance of Electric Plant	103,968	69,315
33	Maintenance of Misc Hydraulic Plant	184,025	122,689
34	Total Production Expenses (total 23 thru 33)	1,699,829	1,133,274
35	Expenses per net KWh	0.0036	0.0036

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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;Stor	Run-of-River;Stor	Run-of-River;Stor	1
Semi-Outdoor	Conventional	Conventional	2
1958	1911	1924	3
1958	1952	1931	4
40.80	18.90	51.00	5
57	28	44	6
7,928	8,027	7,939	7
			8
58	25	44	9
43	20	49	10
0	0	8	11
205,559,000	108,855,000	261,676,000	12
			13
377,100	86,408	9,457	14
3,777,075	2,753,594	5,283,098	15
22,200,090	37,209,588	19,383,479	16
8,031,622	6,184,799	8,906,515	17
1,651,804	458,019	2,292,242	18
5	54	1,769	19
36,037,696	46,692,462	35,876,560	20
883.2769	2,470.5006	703.4620	21
			22
129,567	99,801	-980,009	23
46,774	38,704	47,519	24
413,078	51,900	430,586	25
178,733	173,426	206,810	26
105,568	88,514	365,701	27
-3,529	0	-19,263	28
191,041	19,715	55,036	29
0	0	70,995	30
51,016	13,232	290,599	31
50,539	122,964	22,890	32
273,872	166,715	338,774	33
1,436,659	774,971	829,638	34
0.0070	0.0071	0.0032	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 2011/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
Semi-Outdoor	Semi-Outdoor	Conventional	2
1964	1964	1895	3
1964	1964	1953	4
247.00	165.00	15.40	5
306	0	21	6
7,437	0	8,023	7
			8
338	0	18	9
210	0	9	10
41	0	1	11
1,110,648,000	740,469,000	125,544,000	12
			13
3,726,481	2,521,011	572,077	14
12,072,748	8,024,457	9,309,565	15
158,372,233	103,541,047	23,016,796	16
20,871,516	13,908,827	13,493,897	17
1,346,861	903,201	0	18
0	106	2,224	19
196,389,839	128,898,649	46,394,559	20
795.1006	781.2039	3,012.6337	21
			22
411,829	274,567	106,582	23
125,287	83,529	32,050	24
2,581,886	1,721,394	55,244	25
139,386	92,929	106,268	26
950,176	633,574	96,598	27
66,274	44,184	0	28
170,435	113,629	11,136	29
10,687	7,125	0	30
122,378	81,590	125,759	31
296,319	197,556	40,959	32
676,539	446,015	119,724	33
5,551,196	3,696,092	694,320	34
0.0050	0.0050	0.0055	35

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

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

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

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

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

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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 2011/Q4

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

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

FERC Licensed Project No. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	6	104,631
2	Oregon Military Dept/A.F.R.C	2001	1.60	1.6	39	164,147
3	US Bank Corp Columbia Center	2001	6.40	6.2	333	488,059
4	Providence Business Center	2004	2.00	1.8	31	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	46	191,440
7	Stimson Lumber	2005	0.57	0.5	8	160,255
8	FORTIX (ViaWest)	2005	1.00	0.9	3	91,780
9	Skyline	2005	2.00	1.8	26	201,526
10	Tri-Quint	2005	0.60	0.5	7	109,968
11	NCCWC- Filter Plant	2005	2.00	1.8	30	122,958
12	PCC Structurals	2005	1.00	0.9	7	114,584
13	Providence Portland Medical Center	2005	6.00	5.4	240	256,702
14	Salem Hospital	2006	4.00	3.6	133	188,494
15	Sunrise Water Authority Pump Station	2006	1.25	1.1	16	88,272
16	Providence Newberg Hospital	2006	1.50	1.4	40	156,833
17	Sungard DSG	2006	2.00	1.8	27	331,845
18	Kaiser Sunnyside Hospital	2007	4.50	4.0	146	352,752
19	Newberg Waste Water Treatment Plant	2008	2.00	1.8	36	154,458
20	Xerox Corp	2007	4.00	3.6	102	380,259
21	Newberg Water Treatment Plant	2007	1.00	0.9	15	78,159
22	Solaicx	2008	1.00	0.9	17	62,963
23	Solar World	2008	3.00	2.7	117	219,984
24	Oregon Dept of Admin Serv - Data Center	2010	2.00	1.8	66	277,254
25	Sanyo	2010	1.00	0.9	10	43,144
26	Sysco Foods	2010	2.00	1.8	2	184,781
27	Total					5,172,924
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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 2011/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			695	diesel-low s	1,779	1
102,592		5,384	4,030	diesel-low s or gas	1,607	2
76,259			16,556	diesel-low s	2,243	3
192,972		6,459	732	diesel-low s	2,293	4
93,476		13,884	7,750	diesel-low s	1,721	5
119,650		6,737	2,342	diesel-low s	2,279	6
283,638		1,158	1,037	diesel-low s	2,371	7
91,780		6,114	1,940	diesel-low s	2,393	8
100,763		4,684	732	diesel-low s	2,229	9
183,279		867		diesel-low s	2,700	10
61,479		9,865		diesel-low s	2,329	11
114,584			2,229	diesel-low s	1,779	12
42,784		23,964	4,192	diesel-low s	2,343	13
47,124		13,172	9,583	diesel-low s	2,243	14
70,617		2,972	6,295	diesel-low s	2,207	15
104,555			1,609	diesel-low s	2,343	16
165,922		2,619	1,285	diesel-low s	2,336	17
78,389			11,302	diesel-low s	1,471	18
77,229			3,067	diesel-low s	2,350	19
95,065		15,338	1,498	diesel-low s	2,329	20
78,159		8,886	3,607	diesel-low s	2,329	21
62,963			1,972	diesel-low s	2,364	22
73,328		7,138	2,230	diesel-low s	2,200	23
138,627		7,158	5,941	diesel-low s	2,221	24
43,144		2,258	2,621	diesel-low s	2,300	25
92,391			986	diesel-low s	1,614	26
		138,657	94,231			27
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Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/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	178.00		1
4	JOHN DAY	GRIZZLY '1'	500.00	500.00	ST. TOWER	88.42		1
5	JOHN DAY	GRIZZLY '2'	500.00	500.00	ST. TOWER	88.40		1
6	MISCELLANEOUS	MISCELLANEOUS			-			
7	BOARDMAN	BPA SLATT	500.00	500.00	ST. TOWER	17.80		1
8	COYOTE SPRINGS	BPA SLATT	500.00	500.00	ST. TOWER	28.10		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	ST. TOWER	6.82		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	23.60		1
25	BETHEL	BPA TIE (SANTIAM)	230.00	230.00	H-WOOD	3.60		1
26	BETHEL	McLOUGHLIN	230.00	230.00	H-WOOD	35.70		1
27	CARVER	GRESHAM	230.00	230.00	H-WOOD	7.39		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	0.80		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	802.29	543.22	59

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 2011/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 Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	GRESHAM	LINNEMAN	230.00	230.00	ST. TOWER	0.26		1
2	McLOUGHLIN	SHERWOOD	230.00	230.00	ST. TOWER	11.10		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	MURRAYHILL	SHERWOOD	230.00	230.00	ST. TOWER	5.68		2
8	PORT WESTWARD	TROJAN	230.00	230.00	ST. MONOP	18.80		1
9			230.00	230.00	ST. MONOP	9.39		1
10	TROJAN	ST. MARY'S W.	230.00	230.00	H-WOOD	0.10		1
11			230.00	230.00	ST. TOWER	3.86		2
12			230.00	230.00	ST. TOWER	4.80		1
13			230.00	230.00	ST. TOWER	33.20		2
14	TROJAN	RIVERGATE	230.00	230.00	ST. TOWER		32.20	2
15			230.00	230.00	ST. TOWER	2.90		2
16	Tot Nonproj 230kv Costs							
17	GRESHAM	TROUTDALE	230.00	230.00	ST. TOWER		7.00	1
18	BOARDMAN	PPL DALREED	230.00	230.00	H-WOOD	16.75		1
19	Tot 230KV LINE EXPENSES							
20								
21	PROJECT 115 KV LINES							
22	FARADAY	MCLOUGHLIN	115.00	115.00	H-WOOD	14.70		1
23	NORTH FORK	FARADAY	115.00	115.00	H-WOOD	2.79		1
24	OAK GROVE	FARADAY	115.00	115.00	DC LATTICE	18.68		2
25	OAK GROVE	MCLOUGHLIN	115.00	115.00	H-WOOD	14.70		2
26			115.00	115.00	DC LATTICE	18.68		2
27	Tot 115KV LINE EXPENSES							
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	802.29	543.22	59

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
1780MCMACSR	50,953	1,645,820	1,696,773					2
1780MCMACSR	275,427	15,581,384	15,856,811					3
1780MCMACSR		3,717,535	3,717,535					4
1780MCMACSR		3,716,694	3,716,694					5
	5,904		5,904					6
1480MCMACSR		4,620,708	4,620,708					7
1780MCMACSR		3,624,934	3,624,934					8
								9
								10
								11
								12
								13
	1,194,326	43,098,818	44,293,144					14
				1,197,210	1,154,485	1,120,895	3,472,590	15
								16
1.6 IN. AACTW		3,040,852	3,040,852					17
								18
795MCMACSR	7,579	299,772	307,351					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
	11,120,108	145,794,555	156,914,663	1,681,714	1,621,698	1,131,081	4,434,493	36

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
1272MCMAAC								7
2156MCMACSS								8
2156MCMACSS								9
1272MCMAAC								10
1272MCMAAC								11
1590MCMAAC								12
1590MCMAAC								13
1590MCMAAC								14
1272MCMACSR								15
	9,430,899	62,567,469	71,998,368					16
954KCMACSR								17
795KCMAAC		973,248	973,248					18
				416,613	401,745	3,508	821,866	19
								20
								21
795KCMACSR		886,145	886,145					22
556KCMACSR	120,248	621,351	741,599					23
250CU	12,477	503,937	516,414					24
795KCMACSR								25
250CU	22,295	895,888	918,183					26
				67,891	65,468	6,678	140,037	27
								28
								29
								30
								31
								32
								33
								34
								35
	11,120,108	145,794,555	156,914,663	1,681,714	1,621,698	1,131,081	4,434,493	36

Schedule Page: 422 Line No.: 2 Column: a

Jointly owned with BA Leasing BSC, LLC. Total length is indicated. Costs are respondent's share.

Schedule Page: 422 Line No.: 3 Column: a

Jointly owned with BA Leasing BSC, LLC. Total length is indicated. Costs are respondent's share.

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

Owned and operated by Bonneville Power Administration. Contribution in aid of construction made in 2011 to Bonneville Power Administration for the reconductoring of 1.25 miles of the John Day to Grizzly #1 500-kv line.

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

Owned and operated by Bonneville Power Administration. Contribution in aid of construction made in 2011 to Bonneville Power Administration for the reconductoring of 1.25 miles of the John Day to Grizzly #2 500-kv line.

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

Jointly owned with Idaho Power Company, Power Resources Cooperative and BA Leasing BSC, LLC. Total length is indicated. Costs are respondent's share.

Schedule Page: 422 Line No.: 8 Column: a

Contribution in Aid of Construction made in 1995 to Bonneville Power Administration

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

Contribution in Aid of Construction made in 2007 to Bonneville Power Administration.

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.: 17 Column: a

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

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

Jointly owned with Idaho Power Company, Power Resources Cooperative, and BA Leasing BSC, LLC. 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 2011/Q4

TRANSMISSION LINES ADDED DURING YEAR

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

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	No Additions in 2011						
2							
3							
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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 2011/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 No.
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)	
									1
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Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/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	12 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	Curtis, Portland, OR	Distrib./unattended	115.00	13.00	
28	Curtis, Portland, OR	Distrib./unattended	13.00	11.00	
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	Delaware, Portland, OR	Distrib./unattended	115.00	11.00	4.16
33	Denny, Beaverton, OR	Distrib./unattended	115.00	13.00	
34	Dilley, near Forest Grove, OR	Distrib./unattended	57.00	13.00	
35	Dunn's Corner, near Sandy,OR	Distrib./unattended	57.00	13.00	
36	Durham, Tigard , OR	Distrib./unattended	115.00	13.00	
37	E., East Yard, Portland, OR	Distrib./unattended	115.00	13.00	
38	E., East Yard, Portland, OR	Distrib./unattended	115.00	11.00	
39	E., West Yard, Portland, OR	Distrib./unattended	115.00	13.00	
40	E., West Yard, Portland, OR	Distrib./unattended	115.00	11.00	

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/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	Eagle Creek, Eagle Creek, OR	Distrib./unattended	57.00	13.00	
2	Eastport, Portland, OR	Distrib./unattended	115.00	13.00	
3	Elma, near Salem, OR	Distrib./unattended	57.00	13.00	
4	Estacada, Estacada, OR	Distrib./unattended	57.00	12.50	
5	Fairmount, Salem, OR	Distrib./unattended	115.00	13.00	
6	Fairview, Fairview, OR	Distrib./unattended	115.00	13.00	
7	Forest Grove BPA, Forest Grove, OR	Distrib./unattended	115.00		
8	Garden Home, near Portland, OR	Distrib./unattended	115.00	13.00	
9	Glencoe, Portland, OR	Distrib./unattended	115.00	13.00	
10	Glencullen, Portland, OR	Distrib./unattended	115.00	13.00	
11	Glendoveer, near Portland, OR	Distrib./unattended	115.00	13.00	
12	Glisan, Gresham, OR	Distrib./Unattended	115.00	13.00	
13	Grand Ronde, Grand Ronde, OR	Distrib./unattended	115.00	57.00	13.00
14	Grand Ronde, Grand Ronde, OR	Distrib./unattended	115.00	13.00	
15	Harborton, near Portland, OR	Distrib./unattended	115.00	13.00	
16	Harmony, near Milwaukie, OR	Distrib./unattended	115.00	13.00	
17	Harrison Sub, Portland, OR	Distrib./unattended	115.00	13.00	
18	Harrison Sub, Portland, OR	Distrib./unattended	57.00	11.00	4.16
19	Hayden Island, near Portland, OR	Distrib./unattended	115.00	13.00	
20	Hemlock, Portland, Or	Distrib./unattended	115.00	13.00	
21	Hillcrest, Salem , OR	Distrib./unattended	115.00	13.00	
22	Hillsboro, Hillsboro , OR	Distrib./unattended	57.00	13.00	
23	Hogan North, Gresham, OR	Distrib./unattended	115.00	13.00	
24	Hogan South, Gresham, OR	Distrib./unattended	115.00	57.00	13.00
25	Hogan South, Gresham, OR	Distrib./unattended	115.00	13.00	
26	Holgate, Portland, OR	Distrib./unattended	57.00	13.00	
27	Huber, near Beaverton, OR	Distrib./unattended	115.00	13.00	
28	Indian, near Salem, OR	Distrib./unattended	115.00	13.00	
29	Island, near Milwaukie, OR	Distrib./unattended	115.00	13.00	
30	Jennings Lodge, Jennings Lodge, OR	Distrib./unattended	115.00	13.00	
31	Kelley Point, Portland, OR	Distrib./unattended	115.00	13.00	
32	Kelly Butte, Portland, OR	Distrib./unattended	115.00	13.00	
33	King City, near King City, OR	Distrib./unattended	115.00	13.00	
34	Leland, Oregon City, OR	Distrib./unattended	57.00	13.00	
35	Lents, near Portland, OR	Distrib./unattended	115.00	13.00	
36	Lents, near Portland, OR	Distrib./unattended	57.00	11.00	
37	Lents, near Portland, OR	Distrib./unattended	13.00	11.00	
38	Liberty, Salem, OR	Distrib./unattended	115.00	13.00	
39	Main, Hillsboro, OR	Distrib./unattended	57.00	13.00	
40	Market Street, Salem, OR	Distrib./unattended	115.00	12.50	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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	McClain, Salem, OR	Distrib./unattended	57.00	13.00	
2	Meridian, near Tualatin, OR	Distrib./unattended	115.00	13.00	
3	Middle Grove, near Middle Grove, OR	Distrib./unattended	57.00	13.00	
4	Midway, near Portland, OR	Distrib./unattended	115.00	13.00	
5	Mill Creek, near Salem, OR	Distrib./unattended	115.00	13.00	
6	Mobile sub No. 1, OR	Distrib./unattended	115.00	57.00	13.00
7	Mobile sub No. 2, OR	Distrib./unattended	115.00	57.00	13.00
8	Mobile Sub No. 3, OR	Distrib./unattended	115.00	57.00	12.50
9	Mobile Sub No. 4, OR	Distrib./unattended	115.00	57.00	13.00
10	Molalla, Molalla, OR	Distrib./unattended	57.00	13.00	
11	Mt. Angel, Mt. Angel, OR	Distrib./unattended	57.00	13.00	
12	Mt. Pleasant, Oregon City , OR	Distrib./unattended	115.00	13.00	
13	Multnomah, Portland, OR	Distrib./unattended	115.00	13.00	
14	Murrayhill, Beaverton, OR	Distrib./unattended	115.00	13.00	
15	Newberg, Newberg, OR	Distrib./unattended	115.00	13.00	
16	North Marion, near Woodburn, OR	Distrib./unattended	57.00	13.00	
17	North Plains, North Plains, OR	Distrib./unattended	57.00	13.00	
18	Northern, Portland, OR	Distrib./unattended	57.00	11.00	
19	Oak Hills, near Beaverton, OR	Distrib./unattended	115.00	13.00	
20	Oregon City - BPA, near Wilsonville, OR	Distrib./unattended	57.00		
21	Orenco, near Hillsboro, OR	Distrib./unattended	115.00	57.00	13.00
22	Orenco, near Hillsboro, OR	Distrib./unattended	115.00	13.00	
23	Orient, near Gresham, OR	Distrib./unattended	57.00	13.00	
24	Oswego, Lake Oswego, OR	Distrib./unattended	115.00	13.00	
25	Oxford, Salem, OR	Distrib./unattended	115.00	13.00	
26	Peninsula Park, Portland, OR	Distrib./unattended	115.00	13.00	
27	Pleasant Valley, near Portland, OR	Distrib./unattended	115.00	12.50	
28	Portsmouth, Portland, OR	Distrib./unattended	115.00	13.00	
29	Progress, near Tigard, OR	Distrib./unattended	115.00	13.00	
30	Raleigh Hills, near Portland, OR	Distrib./unattended	115.00	13.00	
31	Ramapo, near Portland, OR	Distrib./unattended	115.00	13.00	
32	Redland, near Oregon City, OR	Distrib./unattended	115.00	13.00	
33	Reedville, near Beaverton, OR	Distrib./unattended	115.00	13.00	
34	Rhodendron Switching, OR	Distrib./unattended	57.00		
35	Rivergate South Yard, near Portland, OR	Distrib./unattended	115.00	13.00	
36	Rivergate South Yard, near Portland, OR	Distrib./unattended	115.00	11.00	
37	Riverview, Portland, OR	Distrib./unattended	115.00	13.00	
38	Rockwood, near Gresham, OR	Distrib./unattended	115.00	13.00	
39	Rosemont, near Lake Oswego, OR	Distrib./unattended	115.00		
40	Roseway, Hillsboro, OR	Distrib./unattended	115.00	13.00	

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
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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	Ruby, North, Gresham, OR	Distrib./unattended	57.00		
2	Ruby, South, Gresham, OR	Distrib./unattended	57.00	13.00	
3	Salem-PGE, near Salem, OR	Distrib./unattended	57.00	13.00	
4	Sandy, Sandy, OR	Distrib./unattended	57.00	13.00	
5	Scappoose, Scappoose, OR	Distrib./unattended	115.00		
6	Scholls Ferry, Beaverton, OR	Distrib./unattended	115.00	13.00	
7	Scoggin, near Gaston, OR	Distrib./unattended	57.00	13.00	
8	Sellwood, Portland, OR	Distrib./unattended	115.00	57.00	13.00
9	Sellwood, Portland, OR	Distrib./unattended	115.00	13.00	
10	Sheridan, Sheridan, OR	Distrib./unattended	57.00	13.00	
11	Silverton, Silverton, OR	Distrib./unattended	57.00	13.00	
12	Six Corners, Six Corners, OR	Distrib./unattended	115.00	13.00	
13	Springbrook, Newberg, OR	Distrib./unattended	115.00	13.00	
14	Springdale, near Springdale, OR	Distrib./unattended		12.50	
15	St. Helens, near St. Helens, OR	Distrib./unattended	115.00		
16	St. Johns-BPA, near Portland, OR	Distrib./unattended		11.00	
17	St. Louis, St. Louis, OR	Distrib./unattended	57.00	13.00	
18	St. Marys, East Yard, near Beaverton, OR	Distrib./unattended	115.00	13.00	
19	Stephens, Portland, OR	Distrib./unattended	57.00	13.00	
20	Stephens, Portland, OR	Distrib./unattended	57.00	11.00	
21	Stephens, Portland, OR	Distrib./unattended	11.00	4.15	
22	Sullivan, West Linn, OR	Distrib./unattended	115.00	13.00	
23	Summit, Government Camp, OR	Distrib./unattended	57.00	13.00	
24	Summit, Government Camp, OR	Distrib./unattended	24.00	13.00	
25	Sunset, near Hillsboro, OR	Distrib./unattended	115.00	13.00	
26	Swan Island, Portland, OR	Distrib./unattended	115.00	13.00	
27	Sylvan, near Portland, OR	Distrib./unattended	115.00	13.00	
28	Tabor, Portland, OR	Distrib./unattended	115.00	13.00	
29	Tabor, Portland, OR	Distrib./unattended	57.00		
30	Tektronix, Beaverton, OR	Distrib./unattended	115.00	13.00	
31	Tigard, Tigard, OR	Distrib./unattended	115.00	12.50	
32	Town Center, Portland, OR	Distrib./unattended	115.00	13.00	
33	Tualitin, Tualitin, OR	Distrib./unattended	115.00	13.00	
34	Twilight, Canby, OR	Distrib./unattended	57.00	13.00	
35	University, Salem, OR	Distrib./unattended	115.00	13.00	
36	Urban, Portland, OR	Distrib./unattended	115.00	13.00	
37	Waconda, near Hopmere, OR	Distrib./unattended	57.00	12.50	
38	Welches, near Welches, OR	Distrib./unattended	57.00	24.00	13.00
39	Welches, near Welches, OR	Distrib./unattended	57.00	13.00	
40	West Portland, Lower Yard, near Tigard, OR	Distrib./unattended	115.00		

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	West Portland, Upper Yard, near Tigard, OR	Distrib./unattended	115.00	13.00	
2	West Union, near Hillsboro, OR	Distrib./unattended	57.00	12.50	
3	Willamina, near Willamina, OR	Distrib./unattended	57.00	13.00	
4	Willbridge, Portland, OR	Distrib./unattended	115.00	11.00	
5	Wilsonville, near Wilsonville, OR	Distrib./unattended	57.00	13.00	
6	Woodburn, Woodburn, OR	Distrib./unattended	57.00	13.00	
7	Yamhill, near Yamhill, OR	Distrib./unattended	57.00	13.00	
8					
9					
10					
11	Allston, BPA, near Mayger, OR	Transm./unattended	230.00		
12	Bakeoven, BPA, Near Bakeoven, OR	Transm./unattended	500.00		
13	Beaver Plant, near Clatskanie, OR	Transm./unattended	230.00	13.00	
14	Beaver Plant, near Clatskanie, OR	Transm./unattended	230.00	24.00	
15	Bethel, Salem, OR	Transm./unattended	230.00	115.00	13.00
16	Bethel, Salem, OR	Transm./unattended	115.00	57.00	13.00
17	Bethel, Salem, OR	Transm./unattended	115.00	13.00	
18	Biglow Canyon Windfarm	Transm./unattended	230.00	34.50	13.80
19	Blue Lake, Troutdale, OR	Transm./unattended	230.00	115.00	13.00
20	Blue Lake, Troutdale, OR	Transm./unattended	115.00	13.00	
21	Boardman, near Boardman, OR	Transm./unattended	500.00	24.00	
22	Boardman, OR	Transm./unattended	230.00	7.20	
23	Boardman, OR	Transm./unattended	24.00	7.20	
24	Broadview Subst. near Broadview, MT	Transm./unattended	500.00	230.00	
25	Captain Jack, BPA, Near Malin, OR	Transm./unattended	500.00		
26	Carver, Carver, OR	Transm./unattended	230.00	115.00	13.00
27	Carver, Carver, OR	Transm./unattended	115.00	13.00	
28	Colstrip Plant, near Colstrip, MT	Transm./unattended	500.00	26.00	
29	Colstrip Subst. near Colstrip, MT	Transm./unattended	500.00	230.00	
30	Coyote Springs, Boardman, OR	Transm./unattended	500.00		
31	Faraday, Switchyard, OR	Transm./unattended	115.00	57.00	12.50
32	Faraday, Switchyard, OR	Transm./unattended	57.00	11.00	
33	Faraday Plant, near Estacada, OR	Transm./unattended	115.00	12.50	
34	Fort Rock, approx 12 mi NE of Silver Lake, OR	Transm./unattended	500.00		
35	Gresham, near Gresham, OR	Transm./unattended	230.00	115.00	13.00
36	Grizzly, BPA, near Madras, OR	Transm./unattended	500.00		
37	Linneman, near Gresham, OR	Transm./unattended	230.00	115.00	13.00
38	Malin, BPA, near Malin, OR	Transm./unattended	500.00		
39	McLoughlin, near Oregon City, OR	Transm./unattended	230.00	115.00	13.00
40	Monitor, near Monitor, OR	Transm./unattended	230.00	57.00	13.00

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/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	Murryhill, Beaverton, OR	Transm./unattended	230.00	115.00	13.00
2	North Fork, near Estacada, OR	Transm./unattended	115.00	13.00	
3	Oak Grove, Three Lynx, OR	Transm./unattended	115.00	13.00	
4	Oak Grove, Three Lynx, OR	Transm./unattended	115.00	11.00	
5	Oak Grove, Three Lynx, OR	Transm./unattended	13.00	11.00	
6	Oak Grove, Three Lynx, OR	Transm./unattended	13.00	0.48	
7	Pearl, BPA, near Wilsonville, OR	Transm./unattended	230.00		
8	Pelton, near Madras , OR	Transm./unattended	230.00	13.00	
9	Pelton, near Madras, OR	Transm./unattended	13.00	13.00	
10	Port Westward, near Clatskanie, OR	Transm./unattended	230.00	18.00	16.50
11	River Mill, near Estacada, OR	Transm./unattended	57.00	11.00	
12	Rivergate North Yard, near Portland, OR	Transm./unattended	230.00	115.00	13.00
13	Round Butte, near Madras, OR	Transm./unattended	500.00	230.00	12.50
14	Round Butte, near Madras, OR	Transm./unattended	230.00	12.50	
15	Round Butte, near Madras, OR	Transm./unattended	230.00	66.00	12.50
16	Sand Springs, 22 mi E/22 mi S of Bend, OR	Transm./unattended	500.00		
17	Sherwood, near Six Corners, OR	Transm./unattended	230.00	115.00	13.00
18	Slatt, BPA, Arlington, OR	Transm./unattended	500.00		
19	St. Marys, West Yard, near Beaverton, OR	Transm./unattended	230.00	115.00	13.00
20	Sullivan, West Linn, OR	Transm./Unattended	57.00	4.15	
21	Sycan, 27 mi S of Silver Lake, OR	Transm./unattended	500.00		
22	Trojan, near Rainier, OR	Transm./unattended	230.00	12.50	
23					
24	TOTAL MVa		28774.00	4881.18	387.62
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Portland General Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2011/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.
91	14		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
38	2		Capacitor Banks	2	3,600	7
34	2		Capacitor Banks	4	12,000	8
38	2		Capacitor Banks	4	14,400	9
56	2		Capacitor Banks	5	15,000	10
45	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
37	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
17	1		Capacitor Banks	2	7,200	27
11	1					28
125	1					29
22	2		Capacitor Banks	4	6,000	30
22	1					31
7	1					32
56	2		Capacitor Banks	2	6,000	33
13	1		Capacitor Banks	3	9,000	34
14	1		Capacitor Banks	2	3,000	35
56	2		Capacitor Banks	4	12,600	36
140	2		Capacitor Banks	3	21,600	37
63	3		Capacitor Banks	1	8,400	38
63	3		Capacitor Banks	1	24,000	39
70	1		Capacitor Banks	2	31,200	40

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
14	1					1
17	1					2
32	2		Capacitor Banks	4	14,400	3
26	2		Capacitor Banks	2	3,600	4
25	1		Capacitor Banks	1	3,600	5
50	2		Capacitor Banks	2	6,600	6
						7
21	1		Capacitor Banks	2	6,000	8
22	1		Capacitor Banks	2	6,000	9
22	1		Capacitor Banks	2	6,000	10
50	2		Capacitor Banks	3	9,720	11
56	2		Capacitor Banks	4	12,000	12
33	1					13
13	1		Capacitor Banks	2	3,000	14
17	1		Capacitor Banks	2	7,200	15
50	2		Capacitor Banks	4	12,000	16
28	1		Capacitor Banks	2	7,200	17
7	1					18
34	2					19
28	1		Capacitor Banks	2	6,000	20
28	1		Capacitor Banks	2	6,000	21
43	2		Capacitor Banks	4	14,400	22
56	2		Capacitor Banks	4	12,600	23
125	3					24
56	2		Capacitor Banks	4	13,200	25
39	2		Capacitor Banks	2	7,200	26
56	2		Capacitor Banks	2	6,000	27
56	2		Capacitor Banks	3	10,800	28
45	2		Capacitor Banks	4	12,000	29
53	2		Capacitor Banks	4	7,200	30
56	2		Capacitor Banks	4	12,000	31
45	2		Capacitor Banks	2	6,000	32
50	2		Capacitor Banks	4	14,400	33
28	1		Capacitor Banks	2	6,000	34
17	1					35
10	1					36
10	1					37
50	2		Capacitor Banks	4	13,200	38
84	3		Capacitor Banks	6	20,400	39
28	1		Capacitor Banks	2	6,000	40

Name of Respondent Portland General Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2011/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.
23	3					1
84	3		Capacitor Banks	6	19,200	2
50	2		Capacitor Banks	4	12,000	3
34	2		Capacitor Banks	3	10,800	4
17	1		Capacitor Banks	2	6,000	5
15	1					6
19	1					7
29	1					8
34	1					9
42	2		Capacitor Banks	4	9,000	10
20	1		Capacitor Banks	3	15,000	11
45	2		Capacitor Banks			12
39	2		Capacitor Banks	3	9,600	13
56	2		Capacitor Banks	3	10,800	14
45	2		Capacitor Banks	4	12,000	15
31	3		Capacitor Banks	3	15,000	16
20	1		Capacitor Banks	4	18,000	17
28	2					18
56	2		Capacitor Banks	4	14,400	19
						20
280	2					21
78	3		Capacitor Banks	6	18,600	22
15	2					23
34	2		Capacitor Banks	2	7,200	24
50	2		Capacitor Banks	4	12,300	25
28	1		Capacitor Banks	2	6,000	26
55	2		Capacitor Banks	4	12,000	27
28	1					28
50	2		Capacitor Banks	4	13,800	29
28	1		Capacitor Banks	2	6,600	30
17	1		Capacitor Banks	2	6,000	31
22	1					32
84	3		Capacitor Banks	6	18,000	33
						34
22	1		Capacitor Banks	2	7,200	35
22	1		Capacitor Banks	2	6,716	36
28	1		Capacitor Banks	2	6,000	37
78	3		Capacitor Banks	5	10,200	38
						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 2011/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
15	2		Capacitor Banks	2	3,600	2
45	2		Capacitor Banks	4	14,400	3
28	1		Capacitor Banks	2	6,000	4
						5
28	1		Capacitor Banks	2	6,000	6
13	2		Capacitor Banks	1	10,800	7
140	1		Capacitor Banks	1	24,000	8
28	1		Capacitor Banks	2	6,000	9
17	1		Capacitor Banks	3	19,200	10
33	3		Capacitor Banks	2	3,600	11
49	2		Capacitor Banks	2	6,000	12
56	2		Capacitor Banks	5	36,000	13
						14
			Capacitor Banks	1	24,000	15
						16
24	2		Capacitor Banks	2	7,200	17
56	2		Capacitor Banks	4	12,000	18
14	1					19
100	2		Capacitor Banks	2	16,800	20
25	6					21
45	2		Capacitor Banks	5	36,000	22
8	1	1				23
6	1					24
328	7		Capacitor Banks	14	70,800	25
50	2		Capacitor Banks	4	12,000	26
22	1		Capacitor Banks	2	6,000	27
22	1		Capacitor Banks	2	6,000	28
						29
56	2		Capacitor Banks	4	12,000	30
45	2		Capacitor Banks	4	12,000	31
56	2		Capacitor Banks	2	6,000	32
56	2		Capacitor Banks	4	13,200	33
28	1		Capacitor Banks	3	19,200	34
22	1		Capacitor Banks	2	7,200	35
112	4		Capacitor Banks	7	43,200	36
41	2		Capacitor Banks	2	6,000	37
6	1		Capacitor Banks	1	12,000	38
18	2		Capacitor Banks	2	6,600	39
			Capacitor Banks	1	24,000	40

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
56	2		Capacitor Banks	4	13,200	1
28	1		Capacitor Banks	3	15,200	2
24	2		Capacitor Banks	3	7,800	3
20	1					4
84	3		Capacitor Banks	6	18,000	5
42	2		Capacitor Banks	4	13,200	6
15	2		Capacitor Banks	1	1,800	7
						8
						9
						10
						11
						12
464	4					13
170	1					14
502	2					15
140	1					16
28	1		Capacitor Banks	2	6,000	17
480	3					18
320	1					19
28	1		Capacitor Banks	2	6,000	20
685	3					21
55	1					22
55	1					23
80	3					24
						25
640	2					26
56	2		Capacitor Banks	4	12,000	27
164	3					28
100	2					29
300	3					30
140	1					31
32	2					32
27	1					33
			Series Capacitor	1	363,000	34
572	2					35
						36
168	1					37
			Reactors	3	180,000	38
640	2					39
125	1					40

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
320	1					1
53	3	1				2
8	1					3
64	2					4
2	1					5
1	2					6
						7
164	4					8
3	1					9
450	3					10
32	2					11
520	4		Capacitor Banks	2	43,500	12
561	3		Reactors	12	180,000	13
372	3	2				14
22	1					15
			Series Capacitor	1	546,000	16
640	2					17
						18
960	3		Capacitor Banks	3	108,000	19
33	1					20
			Series Capacitor	1	546,000	21
56	2					22
						23
17263	369	4		404	3,433,786	24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Schedule Page: 426 Line No.: 19 Column: a

Switching only. Identified locaton 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

Footnote Linked. See note on 426, Row: 19, col/item:

Schedule Page: 426.1 Line No.: 7 Column: a

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

Schedule Page: 426.2 Line No.: 20 Column: a

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

Schedule Page: 426.2 Line No.: 34 Column: a

Switching only.

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

Switching only.

Schedule Page: 426.3 Line No.: 1 Column: a

Switching only.

Schedule Page: 426.3 Line No.: 5 Column: a

Switching only. Distribution owned by CRPUD.

Schedule Page: 426.3 Line No.: 14 Column: a

Regulating only.

Schedule Page: 426.3 Line No.: 15 Column: a

Switching only. Distribution owned by CRPUD.

Schedule Page: 426.3 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: 426.3 Line No.: 29 Column: a

Switching only.

Schedule Page: 426.3 Line No.: 40 Column: a

Switching only.

Schedule Page: 426.4 Line No.: 11 Column: a

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

Schedule Page: 426.4 Line No.: 12 Column: a

Owned and operated by Bonneville Power Administration. Contribution in aid of constriction made to Bonneville Power Administration in 2011 in the amount of 3,568,430 to FERC account 35300.

Schedule Page: 426.4 Line No.: 21 Column: a

Jointly owned with Idaho Power Company, Power Resources Cooperative and BA Leasing BCS, LLC. PGE has a 65% share of the jointly owned capacity. 100% of the capacity is reported.

Schedule Page: 426.4 Line No.: 22 Column: a

Jointly owned with Idaho Power Company, Power Resources Cooperative, and BA Leasing BCS, LLC. PGE has a 65% share of the jointly owned capacity, 100% of the capacity is reported.

Schedule Page: 426.4 Line No.: 23 Column: a

Jointly owned with Idaho Power Company, Power Resources Cooperative, and BA Leasing BCS, LLC. PGE has a 65% share of the jointly owned capacity. 100% of the capacity is reported.

Schedule Page: 426.4 Line No.: 24 Column: a

Jointly owned with Northwestern Energy LLC, Puget Sound Energy, Inc., PacifiCorp, and Avista Corporation. PGE has a 20% share of the jointly owned capacity. 100% of the capacity is reported.

Schedule Page: 426.4 Line No.: 25 Column: a

Owned and operated by Bonneville Power Administration. Contribution in aid of construction made to Bonneville Power Administration in 2011 in the amount of 1,828,820 to FERC account 35300.

Schedule Page: 426.4 Line No.: 28 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.: 29 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.: 30 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.: 34 Column: a

Line compensation only.

Schedule Page: 426.4 Line No.: 36 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.: 38 Column: a

Owned and operated by Bonneville Power Administration. Contribution in aid of construction made to Boneville Power Administration in 1990 in the amount of 365,797 to FERC account 35300.

Schedule Page: 426.5 Line No.: 7 Column: a

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

Schedule Page: 426.5 Line No.: 8 Column: a

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

Schedule Page: 426.5 Line No.: 9 Column: a

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

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

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

Schedule Page: 426.5 Line No.: 15 Column: a

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.: 16 Column: a

Line compensation only.

Schedule Page: 426.5 Line No.: 18 Column: a

Owned and operated by Bonneville Power Administration. Contribution in aid of construction made to Bonneville Power Administration in 2011 in the amount of 1,813,952 to FERC account 35300.

Schedule Page: 426.5 Line No.: 21 Column: a

Line compensation only.

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 2011/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	418	4,973,098
4	OPUC Order No. 75-953	Corp.		
5				
6	Catering Services	Salmon Springs	921	785,075
7		Hospitality Group		
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	186	759,479
23		Hospitality Group		
24				
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ANNUAL REPORT
OREGON SUPPLEMENT TO FERC FORM 1
For Year Ended December 31, 2011

PORTLAND GENERAL ELECTRIC COMPANY
121 SW Salmon Street
Portland, Oregon

ANNUAL REPORT

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

INDEX

PUC FORM 559 (11000)(04/07)

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	Year of Report
PORTLAND GENERAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 2011

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**	1,832,467,476
2	**Operations & Maintenance Expenses**	(1,199,357,374)
3	**Taxes, Other Than Income**	(96,561,192)
4	**Utility Depreciation, Amortization, Regulatory Expenses**	(223,923,966)
5	**Interest**	(110,414,182)
6	**State Income (Excise) Tax**	(357,920)
7	**Federal Income Tax Depreciation in Excess of Book Depreciation**	(171,237,982)
8	**Other Additions (Subtractions) to Derive Taxable Income**	
9		
10	**Other:**	
11	Taxable Income Not Reported on Books - See Note 1, Pg 14a	6,314,282
12	Deductions Recorded on Books Not Deducted For Tax - See Note 2, Pg 14a	75,352,469
13	Income Recorded on Books Not Included in Return - See Note 3, Pg 14a	(7,890,986)
14	Deductions on Return Not Charged Against Books - See Note 4, Pg 14a	(35,438,670)
15	**Total Other Additions (Subtractions) to Derive Taxable Income**	**38,337,095**
16		
17		
18		
19		
20		
21		
22		
23	**Federal Tax Net Income (Loss) Before NOL**	**68,951,955**
24	**Federal NOL Carryforward**	**(13,154,846)**
25	**Federal Tax Net Income (Loss) After NOL**	**55,797,109**
26	**Computation of Tax:**	
27	Federal Taxable Income X 35%	19,528,988
28	PTC C/F - Noncurrent	(14,646,741)
29	AMT Credit C/F - Noncurrent	(4,882,247)
30	2010 Return To Accrual Adjustment	4,522,937
31	FIN48 UTP Reclass	(2,479,983)
32	2009/2010 IRS Audit Adjustment	(48,312)
33	**TOTAL CURRENT FEDERAL INCOME TAX - (Calculated)**	**1,994,642**
34	**TOTAL CURRENT FEDRAL INCOME TAX - FERC 409.1**	**1,994,642**

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, 2011

CALCULATION OF CURRENT FEDERAL INCOME TAX EXPENSE - Account 409.1

Note 1:	Depreciation, Depletion & Amortization	6,314,282
	Total - Taxable Income Not Reported on Books	6,314,282
Note 2:		
	Depreciation, Depletion & Amortization	16,961,597
	Price Risk Management	7,322,701
	Regulatory Debits	44,557,068
	Total Other	6,511,104
	Total - Deductions Recorded on Books Not Deducted For Tax	75,352,469
Note 3:		
	Depreciation, Depletion & Amortization	(3,058,885)
	Regulatory Credits	(4,832,101)
	Total - Income Recorded on Books Not Included in Return	(7,890,986)
Note 4:		
	Miscellaneous	(35,438,670)
	Total - Deductions on Return Not charged Against Book	(35,438,670)

Name of Respondent	This Report Is:	Date of Report	Year of Report
PORTLAND GENERAL ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 2011

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**	1,832,467,476
2	**Operations & Maintenance Expenses**	(1,199,357,374)
3	**Taxes, Other Than Income**	(96,561,192)
4	**Utility Depreciation, Amortization, Regulatory Expenses**	(223,923,966)
5	**Interest**	(110,414,182)
6	**State Income (Excise) Tax Depreciation in Excess of Book Depreciation**	(14,933,864)
7	**Other Additions (Subtractions) to Derive Taxable Income**	.
8		
9	**Other:**	
10	Taxable Income Not Reported on Books - See note 1, Pg 15a	6,314,281
11	Deductions Recorded on Books Not Deducted For Tax - See Note 2, Pg 15a	75,352,469
12	Income Recorded on Books Not Included in Return - See Note 3, Pg 15a	(7,890,986)
13	Deductions on Return Not Charged Against Books - See Note 4, Pg 15a	(206,676,644)
14	**Total Other Additions (Subtractions) to Derive Taxable Income**	**(132,900,880)**
15		
16		
17		
18		
19		
20		
21		
22		
23	**State Tax Net Income**	**54,376,018**
24	**Computation of Tax:**	
25	Unapportioned Income (Loss)	54,376,018
26	Apportionment Ratio	80.16%
27	Oregon Taxable Income (Loss)	43,586,190
28	Less: Local Tax Deduction after apportionment	(65,924)
29	OR NOL Carryforward	(43,520,266)
30	Oregon Tax Rate	7.6%
31	Oregon Excise Tax	0
32	Oregon Minimum Tax	100,000
33	**OREGON CURRENT UTILITY EXCISE TAX**	**100,000**
34	**MONTANA CURRENT UTILITY INCOME TAX**	**175,675**
35	**MULTNOMAH COUNTY & CITY OF PORTLAND CURRENT UTILITY INCOME TAX**	**82,244**
36	**TOTAL CURRENT STATE & LOCAL INCOME TAX - Computed**	**357,919**
37	**TOTAL CURRENT STATE & LOCAL INCOME TAX - FERC 409.1 (Other)**	**357,919**

STATE OF OREGON - ALLOCATED

Name of Respondent	This Report Is:	Date of Report	Year of Report
	(1) [X] An Original	(Mo, Da, Yr)	
PORTLAND GENERAL ELECTRIC COMPANY	(2) [ ] A Resubmission		Dec. 31, 2011

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

Note 1:	Depreciation, Depletion & Amortization	6,314,282
	Total - Taxable Income Not Reported on Books	6,314,282
Note 2:		
	Depreciation, Depletion & Amortization	16,961,597
	Price Risk Management & Mark-to-Market	7,322,701
	Regulatory Debits	44,557,068
	Miscellaneous	6,511,104
	Total - Deductions Recorded on Books Not Deducted For Tax	75,352,469
Note 3:		
	Depreciation, Depletion & Amortization	(3,058,885)
	Regulatory Credits	(4,832,101)
	Total - Income Recorded on Books Not Included in Return	(7,890,986)
Note 4:		
	Depreciation, Depletion & Amortization	(171,237,982)
	Miscellaneous	(35,438,670)
	Total - Deductions on Return Not charged Against Book	(206,676,653)

POLITICAL ADVERTISING

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	Amount
Building a Better Beaverton-urban renewal campaign	**426.4**	**$ 1,500**
Citizens for School Support-Beaverton school levy	**426.4**	**5,000**
Citizens Opposed to Wasting Your Tax Dollars	**426.4**	**1,000**
Clackamas County Citizens for Jobs and Safety	**426.4**	**1,000**
Columbia River Crossing Coalition	**426.4**	**5,000**
Edison Electric Institute	**426.4**	**120,706**
Friends of Clackamas Community College	**426.4**	**10,000**
PGE Employee Candidate Assistance Fund	**426.4**	**200,000**
Portland Business Alliance PAC	**426.4**	**1,000**
Portland Public Schools Bond Campaign	**426.4**	**25,000**
Require Local Vote on Urban Renewal-Clackamas Cty	**426.4**	**3,000**
Washington2 Advocates-Residential Exchange Ratification	**426.4**	**5,163**
Yes for Oregon City Schools	**426.4**	**1,000**
Yes for Parkrose	**426.4**	**2,000**
TOTAL ITEMS UNDER $1,000	**426.4**	**500**
TOTAL 2011 POLITICAL CONTRIBUTIONS		**$ 381,869**

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 2011 will be provided in PGE's June 1, 2012 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		$ 1,814,376	100%
2. Civic Memberships		33,116	100%
3. Corporate/Industrial Memberships		2,131,175	100%
4. Service Memberships		770	100%
(See attached for details)			
TOTAL		$ 3,979,437	

CIVIC CONTRIBUTIONS	ACCOUNT		AMOUNT
Air Show of the Cascades	426.1	$	1,500
ALS Association of Oregon & SW Washington	426.1		3,315
American Heart Association, Inc	426.1		10,345
American Leadership Forum of Oregon	426.1		5,125
American Lung Association of Oregon	426.1		5,075
American Red Cross - Oregon Trail Chapter	426.1		11,400
Associated Oregon Industries	426.1		1,000
Basic Rights Oregon	426.1		15,000
Beaverton Education Foundation	426.1		5,000
Bicycle Transportation Alliance	426.1		1,000
Blue Ocean Events	426.1		10,000
Boardman Chamber of Commerce (sponsorship)	426.1		2,600
Boys and Girls Clubs of Portland Metropolitan Area	426.1		20,500
B.U.L.L. Session Charity Event	426.1		1,000
Business Education Compact	426.1		2,250
Business For Culture	426.1		5,000
Catlin Gabel School	426.1		3,334
Center for Energy Workforce Development	426.1		5,000
Center for the Arts Foundation	426.1		3,000
Central Oregon Safety Health	426.1		1,000
Children's Charity Tournament	426.1		2,500
City Club of Portland	426.1		5,000
City of Hillsboro	426.1		1,500
City of Portland	426.1		2,500
Classroom Law Project	426.1		3,500
Community Action Organization (Washington County)	426.1		2,500
Community Energy Project, Inc	426.1		10,500
Creative Advocacy Network	426.1		2,500
David Douglas Education Foundation	426.1		1,000
Dayton Education Foundation	426.1		1,000
Dougy Center for Grieving Children	426.1		5,750
E3 Employers for Education Excellence	426.1		25,000
Elders in Action	426.1		3,500

CIVIC CONTRIBUTIONS	ACCOUNT	AMOUNT
Estacada Community Center	426.1	1,000
Estacada Community Foundation	426.1	1,000
Estacada Public Library Foundation	426.1	1,000
Estacada Together	426.1	1,000
Fairview Community Arts Council	426.1	1,000
Family Building Blocks	426.1	5,060
Focus the Nation	426.1	2,250
Folktime, Inc.	426.1	2,325
Foundation For Tigard Tualatin Schools	426.1	1,000
Friends of Trees	426.1	3,098
Garten Services, Inc.	426.1	1,000
Grantmakers of Oregon and Southwest Washington	426.1	1,000
Greenlight Greater Portland	426.1	1,000
Grow Oregon	426.1	15,000
Gresham Chamber of Commerce	426.1	3,500
Hands on Greater Portland	426.1	2,500
Harold Backen Golf Tournament	426.1	2,000
The Hatfield Project	426.1	5,000
Hillsboro Chamber of Commerce	426.1	1,600
Hillsboro Schools Foundation	426.1	2,500
Hispanic Metropolitan Chamber of Commerce	426.1	4,450
Historic Elsinore Theatre	426.1	1,100
Human Solutions Inc.	426.1	1,500
IBEW Local 125 Cope	426.1	1,100
Innovation Partnership	426.1	2,500
International Sustainable Development Foundation	426.1	5,000
Japan America Society of Oregon	426.1	1,500
Jefferson County Livestock Association	426.1	2,000
Junior Achievement	426.1	4,200
Juvenile Diabetes Research Foundation	426.1	4,550
Keizer Chamber of Commerce	426.1	2,000
League of Oregon Cities	426.1	1,500
Marion County Fair	426.1	1,500

CIVIC CONTRIBUTIONS	ACCOUNT	AMOUNT
Marion - Polk Food Share	426.1	1,000
Marylhurst University	426.1	1,500
Mercy Corps	426.1	10,000
Metro Portland New Car Dealers Assoc	426.1	5,000
Mid Valley Mentors	426.1	1,000
Milton-Freewater Area Chamber of Commerce	426.1	1,000
Morrow County Livestock & Growers Assoc	426.1	2,500
Mt Hood Community College Foundation	426.1	2,000
Museum at Warm Springs	426.1	4,700
N Morrow Community Foundation	426.1	2,400
National Association of Counties Oregon	426.1	5,000
Newberg Education Foundation	426.1	1,000
Newberg High School	426.1	1,000
Nonprofit Association of Oregon	426.1	1,000
North Clackamas County Chamber of Commerce	426.1	2,000
North Clackamas Education Foundation	426.1	1,000
Northwest Earth Institute	426.1	1,000
Northwest Energy Coalition	426.1	2,500
Oktoberfest, Inc.	426.1	2,000
OMSI	426.1	25,175
Oregon Association of Minority Entrepreneurs	426.1	7,500
Oregon BEST	426.1	3,500
Oregon Burn Center at Legacy Emanuel Hospital	426.1	3,330
Oregon Business Association	426.1	9,750
Oregon Business Council	426.1	10,000
Oregon Children's Foundation	426.1	2,550
Oregon City Chamber of Commerce	426.1	2,150
Oregon Community Foundation	426.1	2,580
Oregon Cultural Trust	426.1	2,500
Oregon Food Bank, Inc.	426.1	18,770
Oregon Health Sciences Foundation (OHSU Foundation)	426.1	2,750
Oregon Heat	426.1	98,040
Oregon Higher Education Alliance	426.1	5,000

CIVIC CONTRIBUTIONS	ACCOUNT	AMOUNT
Oregon Historical Society	426.1	26,500
Oregon League of Conservation	426.1	1,250
Oregon Mentors	426.1	5,000
Oregon Restaurant Association	426.1	1,620
Oregon State Chamber of Commerce	426.1	3,000
Oregon State Police Foundation	426.1	2,500
Oregon State Society	426.1	2,000
Oregon State University Foundation	426.1	7,800
Oregon Tradeswomen, Inc.	426.1	7,500
Oregon Wildlife Heritage Foundation	426.1	1,000
Oregon Women's Campaign School	426.1	1,000
Oregon Zoo Foundation	426.1	57,000
Pacific Northwest Economic Region	426.1	10,675
Pacific Northwest Lineman Rodeo Association	426.1	15,000
Patriot Day	426.1	1,000
Peregrine Sports, LLC	426.1	250,000
PGE Employee Giving Campaign (various agencies)	426.1	594,383
Pivotal Investments, LLC	426.1	5,000
Portland Business Alliance	426.1	10,350
Portland Business Journal	426.1	20,000
Portland Community College Foundation	426.1	5,000
Portland Energy Future Conference	426.1	3,250
Portland Marathon	426.1	1,500
Portland Opera Association, Inc.	426.1	1,000
Portland Rose Festival Association	426.1	78,400
Portland State University Foundation	426.1	6,250
Portland Schools Foundation	426.1	7,500
Portland Streetcar, Inc.	426.1	10,000
Portland Workforce Alliance	426.1	3,500
Providence Medical Foundation	426.1	3,000
Providence Newberg Health Foundations	426.1	1,525
Reaching and Empowering All People, Inc.	426.1	1,000
Remembering America's Heroes	426.1	2,000

CIVIC CONTRIBUTIONS	ACCOUNT	AMOUNT
Salem Area Chamber of Commerce	426.1	11,100
Salem Hospital Foundation	426.1	1,000
Salem Keizer Education Foundation	426.1	7,500
Salvation Army	426.1	1,018
Sandy Area Chamber of Commerce	426.1	1,500
Schoolhouse Supplies	426.1	4,000
Share the Wealth University	426.1	5,000
Sherman County 4-H	426.1	1,599
Smart Grid Oregon	426.1	1,200
Snow-Cap Communities Charities	426.1	2,500
SOLV	426.1	21,400
Strategic Economic Development Corporation	426.1	2,825
Thomas Alva Edison Foundation	426.1	15,000
Tualatin Chamber of Commerce	426.1	2,500
United Way of Mid-Willamette Valley	426.1	2,000
Urban League of Portland	426.1	2,550
Volunteers of America	426.1	2,550
Western Governors' Association	426.1	10,000
Willamette Falls Heritage Foundation	426.1	2,500
Willamette Heritage Center	426.1	2,000
Willamette Riverkeeper	426.1	1,000
Woodburn Chamber of Commerce	426.1	1,360
World Arts Foundation, Inc.	426.1	1,000
Young Audiences of Oregon, Inc.	426.1	1,850
YWCA OF Greater Portland	426.1	5,000
YWCA OF Salem	426.1	1,500
ITEMS UNDER $1,000		49,301
TOTAL 2011 CIVIC CONTRIBUTIONS		$ 1,814,376

CIVIC MEMBERSHIPS	ACCOUNT		AMOUNT
Citizens Crime Commission	426.5	$	5,000
Gresham Chamber of Commerce	426.5		1,291
Hispanic Metropolitan Chamber of Commerce	426.5		1,500
Japan America Society of Oregon	426.5		1,000
Oregon Sports Authority	426.5		2,500
Portland-Sapporo Sister City Association	426.5		1,000
Salem Chamber of Commerce	426.5		5,000
Washington County Historical Society	426.5		1,250
Wilsonville Chamber of Commerce	426.5		1,030
ITEMS UNDER $1,000	426.5		13,545
TOTAL 2011 CIVIC MEMBERSHIPS		**$**	**33,116**

CORP / INDUSTRIAL MEMBERSHIPS	ACCOUNT	AMOUNT
American Coal Council	930.2	$ 2,500
American Wind Energy Association	426.5	8,000
Associated Oregon Industries	426.5	26,057
Association of Corporate Contributions Professionals	426.5	3,000
Audubon Society of Portland	426.5	2,500
Automatic Meter Reading Association DBA Utilimetrics	930.2	3,500
Black & Veatch Corporation	930.2	11,500
Business Education Compact	426.5	3,500
CEAT International Inc. (CEATI)	930.2	24,150
Center for Energy Workforce Development	921.1	5,000
Clackamas County Business Alliance	426.5	1,000
Columbia Corridor Association	426.5	2,500
Columbia-Willamette Clean Cities Coalition, Inc.	426.5	1,000
Common Ground Alliance	930.2	2,000
Construction Industry Crime Prevention	921.1	1,500
Consumer Electronics Association	426.5	1,250
Corporate Executive Board	426.5	20,500
Curtiss-Wright Flow Control Co. - Scientech (LIS)	230	14,884
Curtiss-Wright Flow Control Co. - Scientech (FOMIS)	930.2	54,100
East Metro Economic Alliance	426.5	1,500
Edison Electric Institute	930.2	445,239
Electrification Coalition	426.5	10,000
Electrification Coalition	930.2	10,000
Ethics and Compliance Officer Association	921	3,500
Grantmakers of Oregon and SW Washington	426.5	1,950
HOLTEC International (User's Group)	230	17,000
Human Resources Policy Association	921	7,286
International Swaps and Derivatives Association, Inc.	930.2	9,500
Metro Multifamily Housing Association	930.2	1,050
Montana Tax Foundation, Inc.	426.5	1,750
NACHA - The Electronics Payment Association	903	4,500
National Coal Transportation Association	930.2	1,250
National Hydropower Association	930.2	19,061
National Safety Council	426.5	1,070
Natural Step Network	426.5	2,750
North American Energy Standards Board (NAESB)	930.2	6,500
Northern Tier Transmission Group	930.2	96,601
Northwest Energy Coalition	930.2	29,400

CORP / INDUSTRIAL MEMBERSHIPS	ACCOUNT	AMOUNT
Northwest Environmental Business Council (NEBC)	426.5	1,350
Northwest Hydroelectric Association	539	1,000
Northwest Public Power Association	930.2	1,500
Oregon Business Association	426.5	12,250
Oregon Business Council	426.5	28,070
Oregon Coalition of Healthcare Purchasers	426.5	2,975
Oregon Economic Development	426.5	5,000
Oregon Solar Energy Industries	930.2	4,000
Pacific NW Utilities Conference Committee (PNUCC)	930.2	69,594
Pittock Mansion	426.5	1,500
Portland Business Alliance	426.5	25,000
Portland Metropolitan Building Owners & Managers Assoc	930.2	5,459
Portland Oregon Visitors Association	426.5	1,000
Public Affairs Council	426.5	2,500
Smart Grid Oregon	930.2	10,000
Solar Electric Power Association (SEPA)	930.2	4,500
Strategic Economic Development Corp. (SEDCOR)	426.5	2,500
Technology Association of America	426.5	5,000
The Freshwater Trust	426.5	2,500
Urban League of Portland	426.5	5,000
USNAP Alliance	426.5	5,000
Utility Wind Integration Group	930.2	5,000
West Associates	930.2	22,580
Western Electricity Coordinating Council	930.2	986,530
Western Energy Institute	930.2	39,101
Western LAMPAC	930.2	2,000
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	4,918
TOTAL 2011 CORP INDUSTRIAL MEMBERSHIPS		$ 2,131,175

SERVICE MEMBERSHIPS	ACCOUNT	AMOUNT
ITEMS UNDER $1,000	426.5	$ 770
TOTAL 2011 SERVICE MEMBERSHIPS		**$ 770**

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		$ 26,660,438

Name	Service Description	Amount
A3O STUDIOS INC	Professional Services	101,110
A WORKSAFE SERVICE INC	Professional Services	28,360
ACCENTURE LLP	Professional Services	896,643
ACCION GROUP INC	Professional Services	131,069
ACXIOM CORPORATION	Professional Services	43,315
ADVISICON INC	Professional Services	32,400
AGG ENTERPRISES INC	Professional Services	25,299
AGRICULTURAL RESEARCH FOUNDATION	Professional Services	25,000
AKIN GUMP STRAUSS HAUER & FELD LLP	Professional Services	93,296
ALLIANCE FOR SUSTAINABLE ENERGY LLC	Professional Services	125,000
AMERICAN STOCK TRANSFER & TRUST CO	Professional Services	46,990
ANALYSIS GROUP INC	Professional Services	163,880
ANDREA HAND MARKETING SVCS INC	Professional Services	123,600
ASSET CONTROL INC	Professional Services	26,751
AT&T CORPORATION	Professional Services	28,132
BAKER BOTTS LLP	Professional Services	2,376,835
BALL JANIK LLP	Professional Services	32,472
BATEMAN SEIDEL MINER BLOMGREN	Professional Services	55,328
BLACK & VEATCH CORPORATION	Professional Services	607,831
BOARDMAN TREE FARM LLC	Professional Services	100,858
BRIDGEWATER GROUP INC	Professional Services	373,303
BROADRIDGE FINANCIAL SOLUTIONS	Professional Services	68,469
BURNS & MCDONNELL	Professional Services	25,122
BUSINESS WIRE, INC	Professional Services	30,688
CHARTWELL INC	Professional Services	30,090
CLASSEN DESIGN	Professional Services	56,150
CLEAR EDGE POWER INC	Professional Services	33,344
CONTRADO BBH HOLDINGS LLC	Professional Services	44,890
CRA INTERNATIONAL INC	Professional Services	71,704
CULTURE CHANGE CONSULTANTS INC	Professional Services	73,178
CUSTOMER RELATIONSHIP METRICS	Professional Services	72,731
DAVID E LONG	Professional Services	56,710
DAVID EVANS & ASSOC INC	Professional Services	41,502
DAVID L BOURKE	Professional Services	32,811
DAVIS WRIGHT TREMAINE LLP	Professional Services	42,335
DELOITTE & TOUCHE LLP	Professional Services	1,658,176
DIGITAL EVOLUTION GROUP LLC	Professional Services	54,520
DOLAN GRIGGS LLP	Professional Services	120,232
DUNN CARNEY ALLEN HIGGINS AND TONGUE LLP	Professional Services	64,943
E SOURCE COMPANIES LLC	Professional Services	81,210
EATON CORPORATION	Professional Services	845,382
ECOLOGY AND ENVIRONMENT INC	Professional Services	132,706
ELCON ASSOCIATES INC	Professional Services	25,229
ELECTRIC POWER RESEARCH	Professional Services	115,200
EMPYREAN BENEFIT SOLUTIONS INC	Professional Services	331,290
ENERDEL INC	Professional Services	374,948
EPIQ CLASS ACTION & CLAIM SOLUTIONS INC	Professional Services	38,195
EXERGETIC SYSTEMS INC	Professional Services	53,408
FARRELL STRATEGIES INC	Professional Services	49,500
FIGHT LLC	Professional Services	142,300
FIRST QUARTILE CONSULTING	Professional Services	47,000
FISCHER ROSS GROUP INC	Professional Services	32,444
FORESEE RESULTS INC	Professional Services	70,000
FREDERICKSON FARMING LLC	Professional Services	55,080
FUCILE & REISING LLP	Professional Services	44,234
GARD EDWARDS & ALDRIDGE INC	Professional Services	42,889
GARRAD HASSAN AMERICA INC	Professional Services	36,017
GENERAL PHYSICS CORP	Professional Services	61,238
GREMAR CITY CENTER PARKING	Professional Services	40,590
GROOM LAW GROUP CHARTERED	Professional Services	154,571
HANSA GCR CUSTOM RESEARCH LLC	Professional Services	61,231
HEWITT ASSOCIATES LLC	Professional Services	172,610
HITACHI CONSULTING CORPORATION	Professional Services	177,390

Name	Service Description	Amount
HODGKINSON STREET LLC	Professional Services	186,126
HOPE PATRICE LAMBERT	Professional Services	80,548
HSBC BANK USA NA CORP TRUST	Professional Services	80,850
IHS GLOBAL INC	Professional Services	96,557
JAMES H JOERGER ED D	Professional Services	125,835
JAMES MACK SHIVELY	Professional Services	25,260
JD POWER AND ASSOCIATES	Professional Services	127,000
JIMMY WAYNE BREWER	Professional Services	55,719
JULIUS N DALZELL	Professional Services	94,928
K&L GATES LLP	Professional Services	26,752
KARI L HASTINGS	Professional Services	41,075
KLEINSCHMIDT ASSOCIATES	Professional Services	89,085
KLOTZ ENERGY SYSTEMS INC	Professional Services	35,820
LEGISLATIVE ADVOCATES INC	Professional Services	105,679
MANAGEMENT COMPENSATION GROUP NW	Professional Services	220,000
MANAGEMENT RESOURCES GROUP INC	Professional Services	190,722
MARC B VICTOR	Professional Services	25,768
MARGOLIS AINSWORTH & KINLAW CONSULTING	Professional Services	271,501
MARIA VICTORIA LARA	Professional Services	86,708
MARKET DECISIONS CORPORATION	Professional Services	33,103
MARKET STRATEGIES	Professional Services	352,252
MARKOWITZ HERBOLD GLADE & MEHLHAF PC	Professional Services	270,802
MERCER HEALTH & BENEFITS LLC	Professional Services	76,127
MERCER INVESTMENT CONSULTING	Professional Services	116,362
MERCER THOMPSON LLC	Professional Services	61,785
MICHAEL A ANDREWS LLC	Professional Services	171,456
MICHAEL PATRICK PARTNERS INC	Professional Services	27,992
MILLER NASH LLP	Professional Services	30,901
MORGAN LEWIS & BOCKIUS LLP	Professional Services	1,791,628
MOTUS RECRUITING & STAFFING LLC	Professional Services	27,504
NAVIGANT CONSULTING INC	Professional Services	37,645
NEWSDATA CORP	Professional Services	45,000
NORMANDEAU ASSOCIATES INC	Professional Services	35,382
NORTH INC	Professional Services	1,743,142
NORTHERN PLAINS	Professional Services	117,486
NYSE MARKET INC	Professional Services	75,440
ONLINE CONSULTING INC	Professional Services	36,600
OREGON STATE BOARD OF HIGHER EDUCATION	Professional Services	25,025
OREGON STATE UNIVERSITY FOUNDATION	Professional Services	160,000
PAY GOVERNANCE LLC	Professional Services	29,613
PERKINS COIE LLP	Professional Services	41,758
PORT OF MORROW	Professional Services	36,750
PORTLAND ADVENTIST MEDICAL CTR	Professional Services	30,522
PORTLAND STATE UNIV FOUNDATION	Professional Services	25,000
PRICEWATERHOUSECOOPERS LLP	Professional Services	862,634
PROTIVITI	Professional Services	63,829
REACTION ENGINEERING INT'L	Professional Services	44,000
RELIANT BEHAVIORAL HEALTH LLC	Professional Services	34,994
RESEARCH INTO ACTION INC	Professional Services	69,459
RICHARD TELL ASSOCIATES INC	Professional Services	31,065
RIDDELL WILLIAMS PS	Professional Services	461,859
SARAH PAGLIASOTTI NEWMAN	Professional Services	43,740
SARGENT & LUNDY LLC	Professional Services	85,043
SATHER BYERLY & HOLLOWAY	Professional Services	105,447
SCI 32 INC	Professional Services	40,000
SECURITAS SECURITY SERVICES	Professional Services	182,525
SKADDEN ARPS SLATE MEAGHER & FLOM LLP	Professional Services	292,795
SLR INTERNATIONAL CORP	Professional Services	132,513
SMITH CREATIVE GROUP	Professional Services	149,387
SOLUTIONSIQ INC	Professional Services	47,163
STANDARD & POOR'S FIN SRVC LLC	Professional Services	114,090
STOEL RIVES LLP	Professional Services	776,968
STRUCTURAL INTEGRITY ASSOCIATES INC	Professional Services	401,663

Name	Service Description	Amount
TETRA TECH EC INC	Professional Services	729,440
THE BRATTLE GROUP INC	Professional Services	317,044
THE CORAGGIO GROUP INC	Professional Services	241,075
THE HACKETT GROUP INC	Professional Services	146,009
THE JK GROUP INC	Professional Services	28,583
THE NORTH BRIDGE GROUP INC	Professional Services	177,680
THERESA HAGERTY	Professional Services	70,928
THOMAS E EBZERY PC	Professional Services	38,916
THOMAS E MARK	Professional Services	28,226
THORNDIKE LANDING LLC	Professional Services	80,000
TONKON TORP LLP	Professional Services	450,577
TOWERS WATSON DELAWARE INC	Professional Services	50,514
TOWERS WATSON PA INC	Professional Services	159,623
TRINITY CONSULTING GROUP LLC	Professional Services	369,229
TWO BY FORE INC	Professional Services	32,305
UMT CONSULTING GROUP LLC	Professional Services	42,989
UNISYS CORPORATION	Professional Services	38,963
URS CORPORATION	Professional Services	460,024
UTILITY INTEGRATION SOLUTIONS INC	Professional Services	113,618
VAN NESS FELDMAN	Professional Services	60,839
VAROLII CORPORATION	Professional Services	247,915
VOCUS INC	Professional Services	33,395
WARM SPRINGS POWER ENTERPRISE	Professional Services	150,000
WESTECH CONSTRUCTION INC	Professional Services	88,438
TOTAL 2011 DONATIONS AND PAYMENTS		**26,660,438**

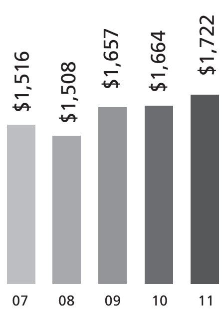
Portland General Electric Company

2011 Annual Report

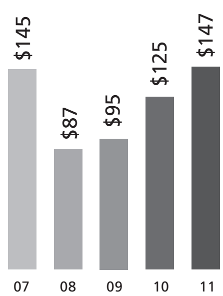
Portland General Electric

Financial Highlights

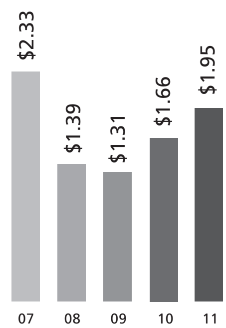
(Dollars in millions, except per share amounts)	2011	2010	2009
Operating revenues	$ 1,813	$ 1,783	$ 1,804
Net operating income	$ 309	$ 267	$ 208
Net income for common stock	$ 147	$ 125	$ 95
Return on equity (average)	9.0%	8.0%	6.6%
Total assets	$ 5,733	$ 5,491	$ 5,172
Dividends declared per common share	$ 1.055	$ 1.035	$ 1.010
Weighted-average shares outstanding (in thousands), diluted	75,350	75,291	72,852
Customers	822,466	820,676	815,739
Long-term debt, including current portion	$ 1,735	$ 1,808	$ 1,744
Long-term debt/capitalization	50.6%	52.8%	53.1%
Senior secured debt ratings (S&P/Moody's)	A–/A3	A–/A3	A–/A3
Commercial paper ratings (S&P/Moody's)	A-2/P-2	A-2/P-2	A-2/P-2
Employees	2,634	2,671	2,708



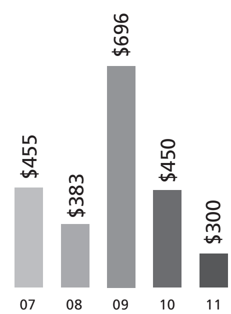
Total retail revenue



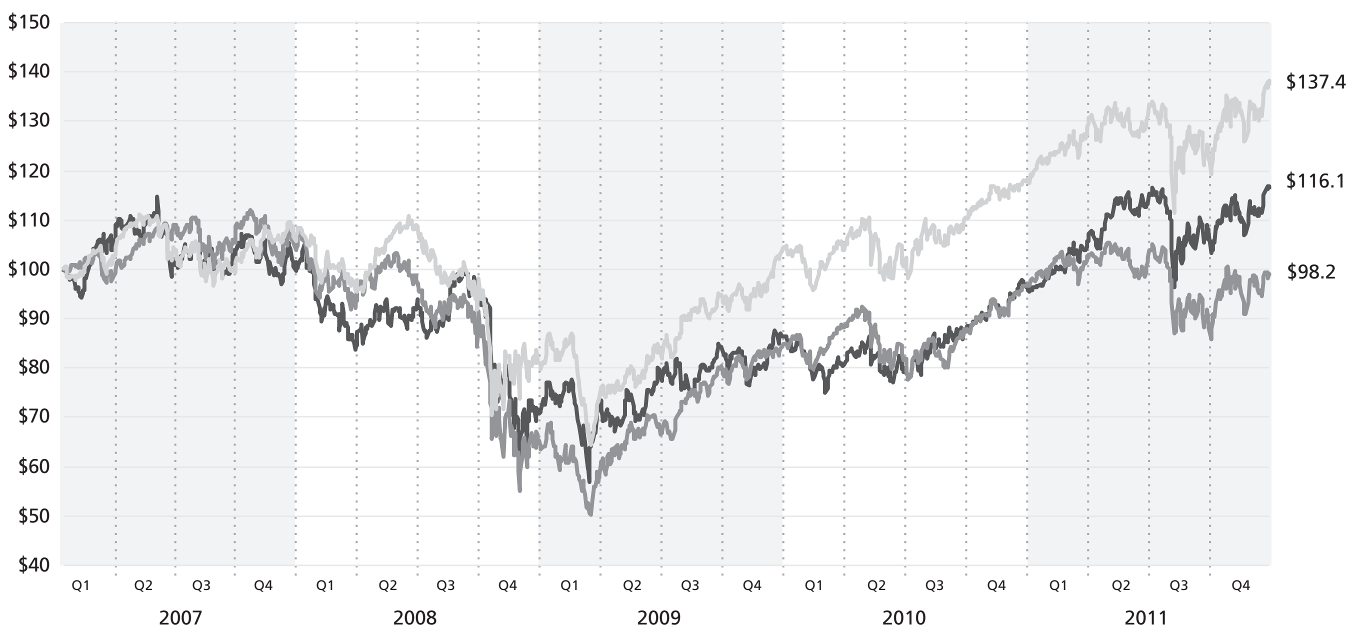
Net income



Earnings per share (diluted)



Capital expenditures



Stock Performance Graph[1]

1. Assumes a $100 investment in Portland General Electric's common stock and each index on December 29, 2006, and that all dividends were reinvested.

About Portland General Electric

Portland General Electric Company (PGE), headquartered in Portland, Oregon, is a fully integrated electric utility serving approximately 822,000 residential, commercial and industrial customers in Oregon. PGE common stock is traded on the New York Stock Exchange under the symbol POR.

To Our Shareholders

In 2011 Portland General Electric continued to build a solid foundation for future growth. Oregon's economy — with unemployment down nearly 2 percent and private-sector payroll growing faster than the national average — certainly played a role in our success. In addition, our focus on operational excellence, business growth and corporate responsibility enabled us to deliver value to customers, shareholders, employees and the communities we serve.

Outstanding operational performance is crucial to PGE's overall success, and I'm proud that customers in every sector express high levels of satisfaction with the service they receive. In 2011 the reliability of our transmission and distribution system and the availability of our generating facilities exceeded our performance targets for the year. With abundant hydro in the Northwest, wholesale power prices were low, enabling us to economically displace a significant amount of our thermal generation, resulting in a reduction in our overall net power costs.

Load growth, along with our strong operations and continued focus on efficiency, delivered a net income of $147 million, or $1.95 per diluted share, for a 9 percent return on equity. Weather-adjusted retail energy deliveries were up 1.4 percent from 2010, with moderate load growth in our residential and commercial customer sectors as well as increased demand from high-tech and other industrial manufacturing customers. We anticipate continued load growth in 2012.

We continue to invest in the business, with capital expenditures of $300 million in 2011. Key projects include improvements at our Boardman and Coyote Springs thermal plants, which were completed on time and on budget and produced better-than-expected results. We also invested in our transmission and distribution system to support growth in the high-tech industry. We are managing our capital structure to support these investments, and at year-end our debt-to-capital ratio was 51 percent, with solid investment-grade credit ratings.

Last summer the Environmental Protection Agency (EPA) approved Oregon's Regional Haze State Implementation Plan, which included our Boardman 2020 Plan to install new emission controls at our Boardman plant, allowing its continued coal-fired operations through 2020. In December the EPA issued Maximum Achievable Control Technology (MACT) rules that apply to the Boardman plant. Based on our full-scale testing results of the controls approved under the 2020 Plan, we believe that the plant will be in compliance with MACT rules.

We are also making progress on the implementation of our 2009 Integrated Resource Plan. Last September the Oregon Public Utility Commission (OPUC) directed us to combine our capacity and energy requests for proposals (RFPs) to take advantage of potential site synergies. We filed a draft combined RFP with the OPUC in January 2012, and the OPUC is scheduled to rule on the RFP in the second quarter, with projected completion of the RFP in late 2012 or early 2013.

Our proposed Cascade Crossing transmission project was one of seven grid modernization projects selected by the federal government's Rapid Response Team for Transmission to streamline federal permitting and increase cooperation at the federal, state and tribal levels. We have established a framework for moving forward on the key agreements for this project with the Bonneville Power Administration and have extended our Memorandum of Understanding with PacifiCorp.

We also continued to collaborate with government, business and other community leaders to support sustained growth of Oregon's economy and to help make the communities we serve vibrant and strong. I am proud of our employees' generosity, including the $1.6 million contributed to the community through our employee giving campaign and the countless hours they volunteer to better our community.

Our success is due to our talented employees, with whom I am honored to work every day. As a result of their commitment to continuous improvement, teamwork and outstanding effort, PGE will make great strides on our priorities of achieving operational excellence, growing the business through strategic investments and being a responsible corporate citizen. After all, this is how we will continue to deliver value to our customers, our shareholders and our communities while keeping a focus on meeting the needs of Oregon's energy future.

Sincerely,

Jim Piro

Jim Piro
President and Chief Executive Officer
March 12, 2012

Form 10-K

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, 2011

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 1-5532-99

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 SW 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 (§ 229.405 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 30, 2011, the aggregate market value of voting common stock held by non-affiliates of the Registrant was $1,900,588,219. For purposes of this calculation, executive officers and directors are considered affiliates.

As of February 17, 2012, there were 75,367,284 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 2012 Annual Meeting of Shareholders to be held on May 23, 2012.

PORTLAND GENERAL ELECTRIC COMPANY
FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2011

TABLE OF CONTENTS

DEFINITIONS

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

Abbreviation or Acronym	Definition
AFDC	Allowance for funds used during construction
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
Colstrip	Colstrip Units 3 and 4 coal-fired generating plant
Coyote Springs	Coyote Springs Unit 1 natural gas-fired generating plant
Dth	Decatherm = 10 therms = 1,000 cubic feet of natural gas
DEQ	Oregon Department of Environmental Quality
EPA	United States Environmental Protection Agency
ESA	Endangered Species Act
ESS	Electricity Service Supplier
FERC	Federal Energy Regulatory Commission
IRP	Integrated Resource Plan
ISFSI	Independent Spent Fuel Storage Installation
kV	Kilovolt = one thousand volts of electricity
kW	Kilowatt = one thousand watts of electricity
kWh	Kilowatt hours
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
OEQC	Oregon Environmental Quality Commission
OPUC	Public Utility Commission of Oregon
PCAM	Power Cost Adjustment Mechanism
Port Westward	Port Westward natural gas-fired generating plant
REP	Residential Exchange Program
RPS	Renewable Portfolio Standard
S&P	Standard & Poor's Ratings Services
SEC	United States Securities and Exchange Commission
SIP	Oregon Regional Haze State Implementation Plan
Trojan	Trojan nuclear power plant
USDOE	United States Department of Energy
VIE	Variable interest entity

PART I

ITEM 1. BUSINESS.

General

Portland General Electric Company (PGE or the Company) was incorporated in 1930 and is a vertically integrated electric utility engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the state of Oregon. PGE 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). The Company'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 order to obtain reasonably-priced power for its retail customers. PGE 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 2011 its service area population was 1.7 million, comprising approximately 44% of the state's population. During 2011, the Company added 1,790 customers and as of December 31, 2011, served a total of 822,466 retail customers.

PGE had 2,634 employees as of December 31, 2011, with 840 employees covered under two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 804 and 36 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 www.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 www.sec.gov.

Regulation and Rates

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 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's next triennial market power study is due in June 2013.

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, 2011, PGE owned approximately 1,100 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 (EPAct 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 has responsibility for compliance and enforcement of these standards. These standards include Critical Infrastructure Protection 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 its Port Westward and Beaver plants. 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.

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 December 28, 2011, is authorized to issue up to $700 million of short-term debt through February 6, 2014.

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 U.S. 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.

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 regulates the issuance of securities, prescribes accounting policies and practices, and reviews applications to sell utility assets, engage in transactions with affiliated companies, and acquire substantial influence over a public utility. The OPUC also reviews the Company's generation and transmission resource acquisition plans, pursuant to an integrated resource planning process. For additional information on the integrated resource planning process, see Power Supply section of this Item 1.

Oregon's Energy Facility Siting Council (EFSC) has regulatory and siting responsibility for large electric generating facilities, high voltage transmission lines, 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 the state'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. 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.

Ratemaking—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 ratemaking 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.

- *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 a forecasted test year, debt-to-equity capital structure, return on equity, and overall rate of return. Revenue requirements and retail customer price changes are proposed based upon such factors. PGE's most recent general rate case was the 2011 General Rate Case, which became effective on January 1, 2011. For additional information, see the Overview section of 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 NVPC, which consists of the cost of power and fuel (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 average regional hydro conditions (based on seventy years of stream flow data covering the period 1928 - 1998) and current hydro operating parameters. The NVPC forecasts also assume average wind conditions (based on wind studies completed in connection with the permitting process of the wind farm) for PGE-owned wind generation and normal operating conditions for thermal generating plants. An initial NVPC forecast, submitted to the OPUC by April 1st each year, is updated during the year and finalized in November. 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 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 that included in base prices (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. 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. The OPUC order in PGE's 2011 General Rate Case provides for a fixed deadband range of $15 million below, to $30 million above, forecasted NVPC, beginning in 2011. For additional information, see the Results of Operations section of 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 has sufficient renewable resources to meet the 2011 - 2014 requirements of the Act. Further, the Company expects to have sufficient resources to meet the 2015 requirements with additional resources included in its most recent Integrated Resource Plan (IRP). It is anticipated that requirements for subsequent years will be met by the acquisition of additional renewable resources, as determined pursuant to the Company's integrated resource planning process. The Act also allows Renewable Energy Credits, resulting from energy generated from qualified renewable resources placed in service after January 1, 1995, to be carried forward, with any excess of what is required to meet the Company's compliance obligation used to fulfill RPS requirements of future years. For additional information, see the Power Supply section in this Item 1.

  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 of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Other ratemaking proceedings 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 based pricing. All commercial and industrial customers are eligible for direct access, whereby customers purchase their electricity from an Electricity Service Supplier (ESS), and PGE continues to deliver the energy to the customers. Large commercial and industrial customers may elect to be served by PGE on a daily market 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 under a market price option.

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.

Residential and small commercial customers can purchase electricity from PGE among a portfolio of price options that include basic cost-of-service, time-of-use, and renewable resource prices.

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 $51 million was collected from customers for this charge in 2011. The Company estimates that $47 million will be collected from customers in 2012.

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 1.8% in 2011 and increased to 2.7% effective January 1, 2012, for applicable customers. Under the tariff, approximately $28 million was collected from eligible customers in 2011. The Company estimates that $42 million will be collected in 2012.

Decoupling—The decoupling mechanism is intended to provide for recovery of reduced revenues resulting from a reduction in electricity sales attributable to energy efficiency and conservation efforts by residential and certain commercial customers. The mechanism provides for customer collection 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 general rate case.

During 2011, PGE recorded an estimated refund of $2 million, which resulted primarily from actual weather adjusted use per customer being slightly higher than levels included in the 2011 General Rate case. Pending review and approval by the OPUC, any resulting refund to customers would be expected over a one-year period beginning June 1, 2012. For 2010, the Company recorded an estimated collection of $8 million, as weather adjusted use per customer was less than levels included in the 2009 General Rate Case. After review, the OPUC approved collections from customers over a one-year period that began June 1, 2011.

As part of the Company's 2011 General Rate Case, the OPUC authorized the continued use of the decoupling mechanism through December 31, 2013.

Regulatory Accounting

PGE is subject to accounting principles generally accepted in the United States of America, 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 anticipated 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 conducts retail electric operations exclusively in Oregon within a service area approved by the OPUC. Retail customers are generally classified within one of the following three categories: i) residential; ii) commercial; or iii) industrial. 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.

In 2011, three ESSs were registered with PGE to transact business with the Company and its customers and provided an average of 242 direct access customers with a total retail load of 988 thousand megawatt hours (MWh) representing 8.5% of PGE's commercial and industrial retail energy deliveries and 5.1% of the Company's total retail energy deliveries for the year. In 2010, ESSs supplied an average of 221 direct access customers with a total retail load representing 9.3% of PGE's commercial and industrial retail energy deliveries and 5.6% of the Company's total retail energy deliveries for the year.

Beginning in January 2012, two ESSs are registered with PGE to transact business with the Company and its customers and are expected to supply energy to 484 direct access customers with an estimated annual load representing 11% of the Company's expected commercial and industrial load and 6% of total retail deliveries. Of these direct access customers, a total of 137, with an estimated annual retail load requirement representing 8% of the Company's expected commercial and industrial load and 5% of total retail deliveries, will be served on a three- or five-year basis.

The Company includes direct access customers in its customer counts and energy delivered to such customers in its total retail energy deliveries although Retail revenues reflect only delivery charges and transition adjustments for these customers.

PGE's Revenues are comprised of the following (dollars in millions):

	Years Ended December 31,					
	2011		2010		2009	
	Amount	%	Amount	%	Amount	%
Retail:						
Residential	$ 877	48%	$ 803	45%	$ 856	47%
Commercial	635	35	601	34	642	36
Industrial	226	13	221	12	166	9
Subtotal	1,738	96	1,625	91	1,664	92
Other accrued revenues, net	(16)	(1)	39	2	(7)	—
Total retail revenues	1,722	95	1,664	93	1,657	92
Wholesale revenues	60	3	87	5	112	6
Other operating revenues	31	2	32	2	35	2
Revenues	$ 1,813	100%	$ 1,783	100%	$ 1,804	100%

Certain averages for retail customers who purchase their energy requirements from the Company* are as follows:

	Years Ended December 31,		
	2011	2010	2009
Average usage per customer (in kilowatt hours):			
Residential	10,740	10,384	11,059
Commercial	68,835	68,040	70,853
Industrial	14,932,550	12,986,466	9,343,838
Average revenue per customer (in dollars):			
Residential	$ 1,160	$ 1,049	$ 1,111
Commercial	6,091	5,769	6,127
Industrial	919,764	859,251	660,839
Average revenue per kilowatt hour (in cents):			
Residential	10.80¢	10.10¢	10.05¢
Commercial	8.85	8.48	8.65
Industrial	6.16	6.62	7.07

* Excludes customers who purchase their energy requirements from ESSs.

For additional information, see Results of Operations in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

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 5% of total retail deliveries. Commercial and industrial customer classes are not dominated by any single industry. While the 20 largest commercial and industrial customers constituted 12% of total retail revenues in 2011, they represented nine different groups, including high technology, paper manufacturing, metal fabrication, health services, and governmental agencies.

Averages over the past three-year period by customer class are as follows, with energy deliveries and revenues expressed as a percentage of the totals:

	Average Number of Customers	Energy Deliveries	Revenues
Residential	717,358	40%	51%
Commercial	102,148	39	37
Industrial	264	21	12

In accordance with state regulations, PGE's retail customer prices are determined through general rate case proceedings and various tariffs filed with the OPUC from time to time, and are based on the Company's cost of service. Additionally, the Company offers different pricing options. Under PGE's daily market price option, the Company delivered electricity to 185 commercial and industrial customers in 2011, representing 1.5% of commercial and industrial deliveries and less than 1% of total retail energy deliveries.

Under the renewable energy options, approximately 85,000, residential and small commercial customers were enrolled compared to 77,000 and 82,000 as of December 31, 2010, and 2009, respectively. Under time-of-use options, approximately 4,500 customers were enrolled compared to 2,100, and 2,130 as of December 31, 2010, and 2009, respectively.

For additional information on customer options, see "*Retail Customer Choice Program*" within the Regulation and Rates 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. Due to the increased use of air conditioning in PGE's service territory, the summer peaks have increased in recent years. Economic conditions can also affect demand from the Company's residential customers, as historical data suggests that high unemployment rates contribute to a decrease in demand. 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 2011, total residential deliveries increased 3.8% compared to 2010 as a result of cooler weather during the heating season, and an increase in the average number of customers. During 2010, total residential deliveries decreased 5.7% compared to 2009, with milder weather conditions accounting for nearly half of the decrease.

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

Demand from the Company's commercial customers is less susceptible to weather conditions than the residential class. 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 2011, favorable weather effects combined with the addition of an average of nearly 700 new customers contributed to the 2% increase in deliveries to commercial customers. During 2011, non-farm employment increased 1.6% in Oregon.

During 2010, as the Oregon economy lost approximately 0.9% of its payroll, the Company's commercial energy deliveries decreased 3.7% compared to 2009 with milder weather, including a very cool summer in 2010, contributing about one-third of the decline.

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 and the applicable tariff. Demand from industrial customers is primarily affected by economic conditions, with weather having little impact on this customer class.

A change in economic activity in Oregon and the United States can also lead to a change in energy demand from the Company's industrial customers. In 2011, industrial deliveries rose 4.7% as demand increased from certain paper production customers, and the general economic conditions improved. In 2010, the Company's industrial energy deliveries rose 3.3% compared to 2009, driven by increased demand from certain paper production customers in the latter half of 2010.

Other accrued revenues, net include 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 regulatory mechanisms for the renewable adjustment clause, the power cost adjustment, and decoupling. See "State of Oregon Regulation" in the Regulation and Rates section of this Item 1 for further information on these items.

Other accrued revenues also include deferrals recorded pursuant to the Residential Exchange Program (REP). Under the REP, the Bonneville Power Administration (BPA) provides federal hydropower benefits to residential and small farm customers of certain investor-owned electric utilities that are expected to continue until the year 2028. PGE receives monthly payments from BPA under the program and passes such payments along to eligible customers in the form of monthly billing credits. For the twelve months ended September 30, 2011, PGE received payments totaling $55 million and received $44 million during each of the twelve month periods ended September 30, 2010 and 2009. Payments for the twelve month period ending September 30, 2012 are expected to be approximately $58 million, with such benefits to be credited to eligible customers.

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. In doing so, the Company attempts to secure reasonably priced power, manage risk, and administer its current long-term wholesale contracts through economic dispatch decisions for its own generation. 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.

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

Other Operating Revenues

Other operating revenues consist primarily of the sale of excess natural gas and oil, as well as revenues from transmission services, excess transmission capacity resales, pole contact rentals, and other electric services provided to customers.

Seasonality

Demand for electricity by PGE's residential customers is affected by seasonal weather conditions, as discussed above. 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 numbers 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
2011	4,650	362
2010	4,187	314
2009	4,391	627
15-year average for 2011	4,219	464

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 and summer loads for the periods indicated along with the corresponding peak load and month in which it occurred:

		Average Load MW	Month	Peak Load MW
2011	Winter	2,612	January	3,555
	Summer	2,233	September	3,340
2010	Winter	2,445	November	3,582
	Summer	2,220	August	3,544
2009	Winter	2,658	December	3,851
	Summer	2,267	July	3,949

The Company tracks and evaluates both base load growth and peak capacity 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, 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.

PGE's base generating resources consist of five thermal plants, 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 Item 2.—"Properties."

The Company also promotes the expansion of renewable energy resources, as well as energy efficiency measures, to meet its energy requirements and enhance customers' ability to manage their energy use more efficiently.

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

	As of December 31,					
	2011		2010		2009	
	Capacity	%	Capacity	%	Capacity	%
Generation:						
Thermal:						
Natural gas	1,172	28%	1,157	24%	1,175	26%
Coal	670	16	670	14	670	15
Total thermal	1,842	44	1,827	38	1,845	41
Hydro	489	12	489	10	489	11
Wind *	450	11	450	9	275	6
Total generation	2,781	67	2,766	57	2,609	58
Purchased power:						
Long-term contracts:						
Capacity/exchange	190	4	540	11	640	14
Mid-Columbia hydro	335	8	507	10	548	12
Confederated Tribes hydro	150	4	150	3	150	3
Wind	44	1	44	1	35	1
Other	210	5	221	5	233	5
Total long-term contracts	929	22	1,462	30	1,606	35
Short-term contracts	458	11	612	13	315	7
Total purchased power	1,387	33	2,074	43	1,921	42
Total resource capacity	4,168	100%	4,840	100%	4,530	100%

* Capacity represents nameplate and differs from expected capacity, which is expected to range from 135 MW to 180 MW, dependent upon wind conditions.

For information regarding actual generating output and purchases for the years ended December 31, 2011, 2010 and 2009, see the Results of Operations section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Generation

That 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.

Thermal PGE has a 65% ownership interest in Boardman, which it operates, and a 20% ownership interest in Colstrip Units 3 and 4. These two coal-fired generating facilities provided approximately 21% of the Company's total retail load requirement in 2011, compared to 26% in 2010 and 20% in 2009. The Company's three natural gas-fired generating facilities, Port Westward, Beaver, and Coyote Springs, provided approximately 11% of its total retail load requirement in 2011 and 24% in 2010 and 2009.

The thermal plants, which have a combined capacity of 1,842 MW, provide reliable power for the Company's customers with plant availability, excluding Colstrip, of 90% in 2011, 94% in 2010, and 84% in 2009 and Colstrip plant availability of 84% in 2011, 95% in 2010, and 68% in 2009.

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 from 2035 to 2055. These plants, which have a combined capacity of 489 MW, provided 10% of the Company's total retail load requirement in 2011, 2010 and 2009, with availability of 100% in 2011 and 99% in both 2010 and 2009. 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 450 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 no sooner than December 31, 2021. The Tribes have a second option to purchase an undivided 0.02% interest in Pelton/Round Butte at its discretion no sooner than 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 installed capacity of approximately 450 MW. It was completed and placed in service in three phases between December 2007 and August 2010. In 2011, Biglow Canyon provided 6% of the Company's total retail load requirement, compared to 4% in 2010 and 3% in 2009, with availability of 97% in 2011 and 96% in both 2010 and 2009. The energy received from wind resources differs from the nameplate capacity and is expected to range from 135 MW to 180 MW 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 standby generators when needed to meet peak demand. The program helps provide operating reserves for the Company's generating resources and, when operating, can supply most or all of DSG customer loads. As of December 31, 2011, there were 31 projects that together can provide approximately 69 MW of diesel-fired capacity at peak times. In addition, there were 12 projects under construction that are expected to provide an additional 30 MW.

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, swap, and option contracts to manage its exposure to volatility in natural gas prices.

Coal *Boardman*—PGE has fixed-price purchase agreements that provide coal for Boardman into 2014. The coal is obtained from surface mining operations in Wyoming and Montana and is delivered by rail under two separate ten-year transportation contracts which extend through 2013.

PGE expects to begin seeking requests for proposal in mid-2012 for the purchase of coal to fill open positions for 2013 and beyond. The terms of any contracts and quality of coal are expected to be staged in alignment with the timing of the installation of required emissions controls. For additional information on Boardman's emissions controls, see the Capital Requirements section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations." PGE believes that sufficient market supplies of coal are available to meet anticipated operations of Boardman for the foreseeable future.

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.

The Beaver generating plant 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 7-day supply of ultra-low sulfur diesel fuel oil at the plant site as of December 31, 2011. 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.

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 30 years and expire at varying dates through 2036.

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 three contracts that provide PGE with firm capacity to help meet the Company's peak loads. The contracts range from 10 MW to 150 MW and expire at various dates from February 2012 through December 2016. They include a seasonal exchange contract with another western utility that helps meet winter--peaking requirements.

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. These contracts expire at various dates from 2017 through 2052. Although the projects currently provide a total of 335 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 150 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.

Wind—The Company has three long-term contracts, which extend to various dates between 2028 and 2035, that provide for the purchase of renewable wind-generated electricity. Although these contracts provide a total of 44 MW of capacity, actual energy received is dependent upon wind conditions.

Other—These primarily consist of long-term contracts to purchase power from various counterparties, including other Pacific Northwest utilities, over terms extending into 2036.

Other also includes contracts that provide for the purchase of renewable solar-powered electricity as follows:

- PGE operates three photovoltaic solar power projects installed in the Portland area, with a combined installed capacity of 3.6 MW. PGE purchases 100% of the energy generated from two of the facilities and purchases any excess energy generated from one facility pursuant to a net metering arrangement with the Oregon Department of Transportation (ODOT);
- PGE has two 25-year purchase agreements for the power generated from two photovoltaic solar projects installed near Salem, Oregon. The construction of the projects was completed in mid-2011, with PGE then purchasing the power generated from these facilities, which have a combined generating capacity of 2.8 MW.

In January 2012, PGE completed the construction of a 1.75 MW photovoltaic solar power project, which was sold and simultaneously leased-back from a financial institution. The Company operates the project and receives 100% of the power generated by the facility.

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's most recent IRP was acknowledged by the OPUC on November 23, 2011. The IRP includes an action plan for the acquisition of new resources and a 20-year strategy that outlines long-term expectations for resource needs and portfolio performance. PGE projects that it needs 873 MWa of new resources by 2015, increasing to 1,396 MWa by 2020, to meet expected customer demand. Such projected energy gaps are driven primarily by continued load growth and the expiration of certain long-term power supply contracts. The projected energy gap increases by approximately 374 MW with the cessation of coal-fired operations at Boardman in 2020.

To meet the projected energy requirements, the IRP includes energy efficiency measures, new renewable resources, new transmission capability, new generating plants, and improvements to existing generating plants, as follows:

- Acquisition of 214 MWa of energy efficiency through continuation of Energy Trust of Oregon programs, with funding to be provided from the existing public purpose charge and through enabling legislation included in Oregon's RPS;
- An additional 101 MWa of wind or other renewable resources necessary to meet requirements of Oregon's RPS by 2015;
- Transmission capacity additions to interconnect new and existing energy resources in eastern Oregon to PGE's services territory. For additional information on the Cascade Crossing Transmission Project (Cascade Crossing), see the Transmission and Distribution section in this Item 1;
- New natural gas generation facilities to help meet additional base load requirements estimated at 300 to 500 MW, which is expected to be available in the 2015 to 2017 timeframe;
- New natural gas generation facilities to help meet peak capacity requirements estimated at up to 200 MW, bi-seasonal peaking supply of 200 MW and winter-only peaking supply of 150 MW, all of which are expected to be available in the 2013 to 2015 timeframe; and
- Continued operations of the Boardman plant, including the addition of certain emissions controls and the continuation of coal-fired operation of the plant through 2020. For additional information about emissions controls for the Boardman plant, see the Capital Requirements section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

In January 2012, PGE requested that the OPUC acknowledge a draft request for proposals (RFP) that is expected to be issued in the second quarter of 2012, seeking electric power generating resources to help meet PGE's capacity and energy needs, as outlined in the IRP discussion above. PGE expects to file a second RFP, for renewable resources, later in 2012.

The Company has filed with the OPUC a motion for a one-year extension to file its next IRP. If the motion is approved as submitted, PGE would be required to file its next IRP no later than November 2013. If not approved as submitted, PGE may be required to file its next IRP as early as November 2012.

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 2011, PGE delivered approximately 20 million MWh in its balancing authority area through approximately 1,100 circuit miles of transmission lines.

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 to 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.

PGE's wholesale transmission activities are regulated by the FERC. 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.

These services 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, PGE's transmission business is managed and operated independently from its power marketing business.

PGE's current acknowledged IRP includes a proposal for an approximate 210-mile, 500 kV transmission project (the Cascade Crossing Transmission Project) that would help meet future electricity demand and improve future grid reliability by transmitting power from new and existing energy resources in eastern Oregon to the Company's service territory. PGE continues to work with other stakeholders in the region in planning the project and is actively engaged in the federal, state, and tribal permitting processes. Subject to obtaining all necessary approvals, the expected in-service date would be late 2016 or early 2017. In October 2011, Cascade Crossing was selected as one of seven transmission projects in the nation to participate in the federal inter-agency Rapid Response Team for Transmission program to improve agency collaboration and expedite federal permitting.

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 Item 2.—"Properties."

Environmental Matters

PGE's operations are subject to a wide range of environmental protection laws and regulations, which pertain to air quality (including climate change), water quality, endangered species and wildlife protection, and hazardous waste. Environmental matters that relate to the siting and operation of generation, transmission, and substation facilities and the handling, accumulation, cleanup, and disposal of toxic and hazardous substances fall under the jurisdiction of various state and federal agencies. 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.

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, sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon monoxide, particulate matter, hazardous air pollutants, and greenhouse gas emissions (GHGs). Oregon and Montana, the states in which PGE facilities are located, also implement and administer certain portions of the CAA and have set standards that are at least equal to federal standards.

In June 2011, the United States Environmental Protection Agency (EPA) approved revised rules to reduce SO_2 and NO_x emissions at Boardman that have resulted in the installation of certain emissions controls during 2011. To further reduce SO_2 emissions, plans call for the use of lower sulfur coal and the addition of a Dry Sorbent Injection system to Boardman in 2014, at an estimated capital cost to the Company of $27 million, including AFDC. The revised rules also provide for coal-fired operation at Boardman to cease no later than December 31, 2020. Construction or acquisition costs of replacement generating capacity will be considered in future customer prices.

In December 2011, the EPA issued new emissions limits under the CAA's National Emission Standards for Hazardous Air Pollutants (NESHAP) regulating hazardous air pollutant emissions, from coal- and oil-fired electric generating units. Emission limits included in the NESHAP are based on the application of maximum achievable control technology (MACT). Based on its review of the rules and the preliminary full-scale test results, the Company believes the Boardman plant should be able to meet the MACT requirements with the installation of the currently planned controls. The operator of the Colstrip plant has provided the Company with estimated costs for emission control modifications to Units 3 and 4 that may be necessary to meet the MACT requirements. Based on this estimate, the Company expects that its share of these costs, as a 20% owner of Units 3 and 4, will not exceed $10 million.

Regulation of mercury emissions is contemplated under NESHAP. However, the states of Oregon and Montana have previously adopted regulations concerning mercury emissions that have had an impact on the Company as follows:

> *Oregon*—The Oregon Environmental Quality Commission (OEQC) has adopted final rules that pertain to mercury emissions from Boardman. Such rules require compliance with stated mercury limits by July 1, 2012, In 2011, PGE installed controls that are expected to eliminate 90% of the mercury emissions from the plant to comply with the rules.
>
> *Montana*—The Montana Board of Environmental Review adopted final rules on mercury emissions from coal-fired generating plants, including Colstrip. With the installation of additional mercury control systems, Colstrip is in compliance with these requirements.

For additional information, see "*Boardman emissions controls*" in the Capital Requirements section of Item 7. —"Management's Discussion and Analysis of Financial Condition and Results of Operations."

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—State, regional, and federal legislative efforts continue with respect to establishing regulation of greenhouse gas (GHG) emissions and their potential impacts on climate change. Recent or pending environmental measures include the following:

- In 2007, the State of Oregon adopted a non-binding policy guideline that sets a goal to reduce GHG emissions to 10% below 1990 levels by 2020. The guideline does not mandate reductions by any specific entity nor does it include penalties for failure to meet the goal.
- In 2009, the U.S. House of Representatives approved legislation that seeks to establish a cap and trade system for GHG emissions. However, the U.S. Senate did not act and it is uncertain whether a cap and trade system will move forward in the near term.
- Effective January 1, 2010, the EPA required mandatory measurement and reporting of GHG emissions. PGE is subject to these requirements and is meeting the monitoring and reporting requirements. Reported data will be used to establish a baseline for measuring progress toward any future emissions reduction targets in the United States.
- In 2010, the EPA finalized rules creating GHG thresholds that apply to the permitting process for stationary sources, such as electric generating facilities, under the Prevention of Significant Deterioration and Title V operating permit programs. The EPA has also issued guidance under these rules relating to Best Available Control Technology (BACT) requirements for new and modified stationary sources. In April 2011, the OEQC approved new state rules to implement these federal requirements and in December 2011, the rules were approved by the EPA. As a result of these rules, new or modified generating facilities may need to satisfy BACT requirements for limiting GHG emissions. The specific requirements applicable to a particular facility would be determined in connection with the permitting process.
- 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 deadlines for setting these standards and guidelines have been delayed and the timing is now unclear.

Any laws that impose mandatory reductions in GHG emissions may have a material impact on PGE, 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 Beaver, Coyote Springs, and Port Westward natural gas-fired facilities, and the Company's ownership interest in Boardman and Colstrip coal-fired facilities, provide approximately 66% of the Company's net generating capacity. 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, the DEQ is responsible for reviewing proposed projects under this requirement to ensure that federally approved activities will meet water quality standards and policies established by the 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. Over the years, these changes have resulted in reductions in hydroelectric generation capacity and shifts in the seasonality of much of the generation due to the timing of stored water releases, both of which can affect the price of power in the regional wholesale market. 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 is implementing a series of 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. 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 Oregon's RPS. Conditions required with the new 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. PGE has developed and implemented such a plan for its transmission and distribution facilities and is in the process of developing a plan for its wind facilities to reduce risks to bird species that can result from Company operations.

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.

The Company's coal-fired generation facilities, Boardman and Colstrip, produce coal combustion byproducts, which have been exempt from federal hazardous waste regulations under the RCRA. The EPA is revisiting this exemption and is considering listing these residuals as hazardous wastes, which would likely have an impact on current disposal practices and could increase the Company's cost of handling these materials and affect operations. The EPA has announced that the final rule would likely be issued in late 2012. 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. PGE is listed by the EPA as a Potentially Responsible Party (PRP) at two Superfund sites as follows:

Portland Harbor—A 1997 investigation by the EPA of a segment of the Willamette River, known as the Portland Harbor, revealed significant contamination of river sediments. The EPA subsequently included Portland Harbor on the federal National Priority List as a Superfund site pursuant to CERCLA and listed sixty-nine PRPs, including PGE, which 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.

Harbor Oil—The Harbor Oil site in north Portland is the location of a company that PGE engaged to process used oil from power plants and electrical distribution systems until 2003. The Harbor Oil facility continues to be utilized by other entities for the processing of used oil and other lubricants. In September 2003, the Harbor Oil site was included on the federal National Priority List as a federal Superfund site and PGE was included among fourteen PRPs.

For additional information on these EPA actions, 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 from the forward-looking statements contained in this Annual Report on Form 10-K, include, but are not limited to, 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, the Company will seek to recover in customer prices most of the costs incurred in connection with the operation of its business, including, among other things, 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 excessive or imprudently incurred. Further, the regulatory process does not guarantee that PGE will be able to achieve the earnings level authorized. Although the OPUC is required to establish rates that are fair, just and reasonable, it has significant discretion in the interpretation of this standard.

In both PGE's 2009 and 2011 general rate cases, overall price increases approved by the OPUC were less than the Company's initial proposals. 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. For additional information regarding the 2011 General Rate Case, see the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

The risk of volatility in power costs is partially mitigated through the Annual Power Cost Update Tariff (AUT) and the PCAM. PGE files an annual AUT with an update of PGE'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 OPUC order in PGE's 2011 General Rate Case provides for a fixed deadband range of $15 million below, to $30 million above, baseline NVPC, beginning in 2011. 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.

A continued weakening of the economy could reduce the demand for electricity and impair the financial stability of some of PGE's customers, which could affect the Company's results of operations.

The weak economy in Oregon over the past several years has resulted in reduced demand for electricity, which could continue. Further reduction in demand could affect the Company's results of operations and cash flows. The weak economy could also result in an increased level of uncollectable customer accounts. Additionally, the Company's vendors and service providers could 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 or under short-term, long-term, or variable-priced contracts. 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 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. Although the Company's PCAM can be expected to partially mitigate adverse financial effects related to market conditions, cost sharing features of the mechanism do not provide for full recovery in customer prices.

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

Weather conditions can adversely affect PGE's revenues and costs, impacting the Company's financial and operating results. Variations in temperatures can affect customer demand for electricity, with warmer-than-normal winters or cooler-than-normal summers reducing energy sales and revenues. 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. 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, reduced efficiency, or higher operating costs.

PGE's current position as a "short" utility requires that the Company supplement its own generation with wholesale market purchases to meet its retail load requirements. 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 and to complete its capital projects. Credit rating agencies evaluate PGE'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, 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 and 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.

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.

Access to capital and credit markets is important to PGE's continued ability to operate. The Company potentially faces significant capital requirements over the next three to five years and expects to issue debt and equity securities, as necessary, to fund these requirements. In addition, because of contractual commitments and regulatory requirements, the Company may have limited ability to delay or terminate certain projects. For additional information concerning PGE's capital requirements, see "Capital Requirements" in the Liquidity and Capital Resources section of 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.

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 stream flows and unfavorable wind conditions can adversely affect generation from PGE's hydroelectric and wind resources. The Company could be required to replace generation from these sources with higher cost power from other facilities or with wholesale market purchases, which could have an adverse effect on operating results.

PGE derives a significant portion of its power supply from its own hydroelectric facilities and from those owned by certain public utility districts in the state of Washington with which the Company has long-term purchase contracts. Regional rainfall and snow pack levels affect stream flows and the resulting amount of generation available from these facilities. Shortfalls in low-cost hydro production would require increased generation from the Company's higher cost thermal plants and/or power purchases in the wholesale market, which could have an adverse effect on operating results.

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

Although the application of the PCAM could help mitigate adverse financial effects from any decrease in power provided by hydroelectric and wind 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 (PTCs).

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 operations or results of operations.

PGE expects that future legislation or regulations could result in limitations on greenhouse gas emissions from the Company's fossil fuel-fired electric generating facilities. Legislation has been introduced in the U.S. Congress that would require greenhouse gas emission reductions from such facilities as well as other sectors of the economy. Although no such legislation has yet been enacted, the House of Representatives passed climate legislation in June 2009. Compliance with any greenhouse gas emission 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 expected 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 $670 million. These credit facilities are available for general corporate purposes and may be used to supplement operating cash flow and provide a primary source of liquidity. The credit facilities may also be used as backup for commercial paper borrowings.

The 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 of 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 emissions 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.

The Company is subject to state and federal requirements concerning emissions from thermal generation plants. For additional information, see "Environmental Matters" in Item 1-"Business." These requirements could adversely affect the Company's results of operations by requiring (i) the installation of additional emissions controls at the Company's generating plants, which could result in increased capital expenditures and (ii) changes to PGE'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, adversely affecting 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 the Company'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 the Company's liabilities under the pension plan. As interest rates decrease, the Company's liabilities increase, potentially requiring additional funding. In 2011, discount rates used to value the pension plan declined substantially. This decline, combined with an increased actuarial loss related to prior year asset under performance, contributed to an increase in pension plan's underfunded status from $77 million as of December 31, 2010 to $147 million as of December 31, 2011.

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 the "Contractual Obligations and Commercial Commitments" table in the Liquidity and Capital Resources section of 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."

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 PGE's ability to deliver electricity and require the Company to incur additional expenses to meet the needs of its customers. In addition, as these contracts expire, PGE could be unable to continue to purchase natural gas, coal or electricity on terms and conditions equivalent to those of existing agreements. The cost and availability of natural gas and coal can also impact the cost and output of the Company's thermal generating plants.

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 consists of generation from hydroelectric and wind projects. Operation of these projects is subject to regulation related to the protection of fish and wildlife. The listing of various species of salmon, wildlife, and plants as threatened or endangered has resulted in significant changes to federally-authorized activities, including those of hydroelectric 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 amount of hydro or wind generation available 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 the Company 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. The Company 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.

The Company 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.

In PGE's 2011 General Rate Case, the OPUC 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, 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 & 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 an aging workforce with a significant number of employees approaching retirement age.

The Company anticipates higher averages of retirement rates over the next ten 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 quality service to its customers and meeting regulatory requirements, both of which could affect operating results.

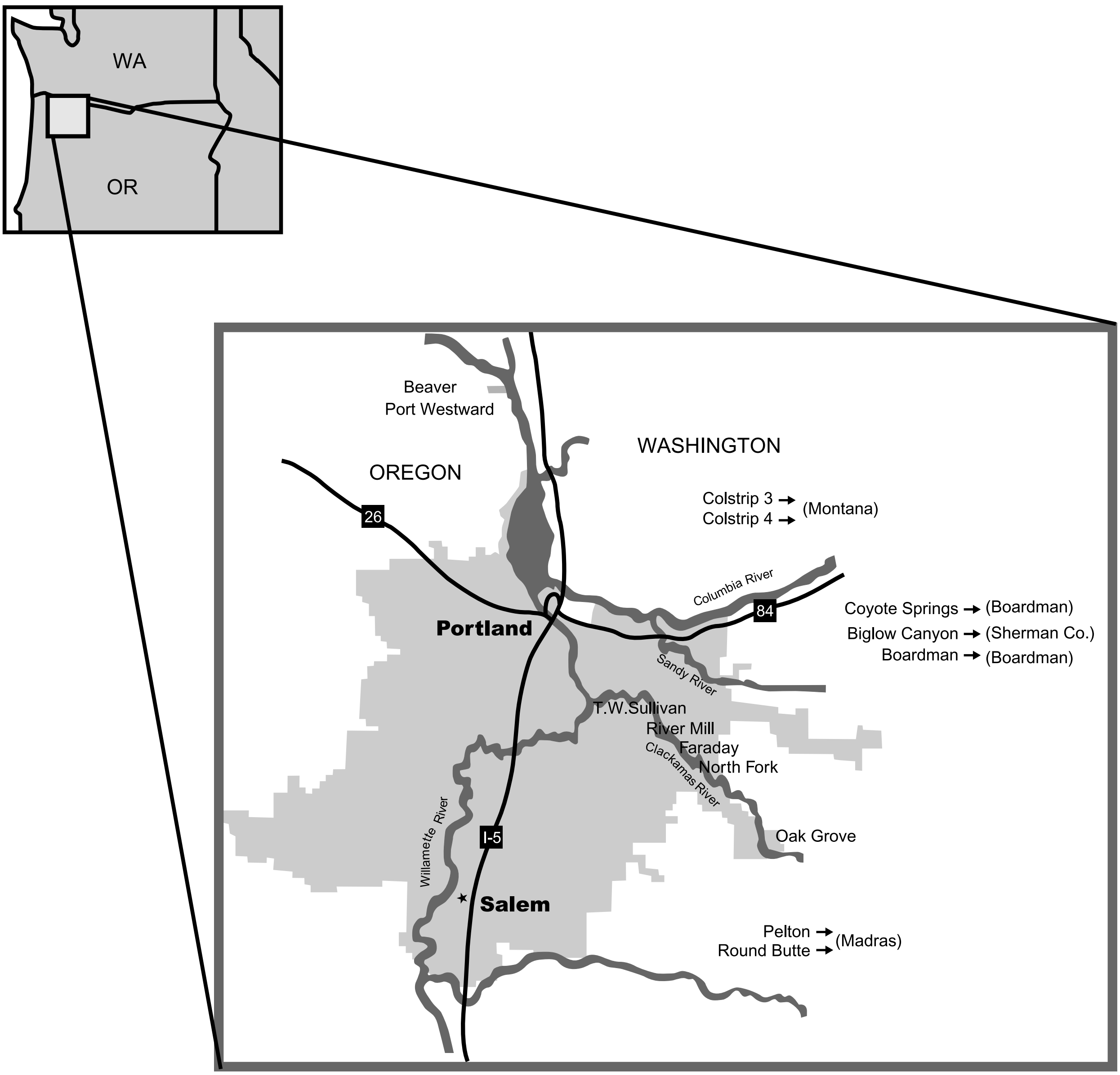
ITEM 1B. UNRESOLVED STAFF COMMENTS.

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. The Company leases its corporate headquarters complex, located in Portland, Oregon. The Indenture securing the Company's First Mortgage Bonds constitutes a direct first mortgage lien on substantially all utility property and franchises, other than expressly excepted property.

The Company's service territory and generating facilities are indicated below:



Generating Facilities

The following are generating facilities owned by PGE as of December 31, 2011:

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	410	
Coyote Springs	Boardman, Oregon	246	
Wind:			
Biglow Canyon	Sherman County, Oregon	450	
Jointly-owned [2]:			
Coal:			
Boardman [3]	Boardman, Oregon	374	
Colstrip [4]	Colstrip, Montana	296	
Hydro:			
Pelton [5]	Deschutes River	73	
Round Butte [5]	Deschutes River	225	
Total net capacity		2,781	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 a 65% ownership interest.
(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. The FERC approved a 40-year license term for the Company's hydroelectric project on the Clackamas River in December 2010 and in March 2011, issued an Order on Rehearing that increased the license period to 45 years.

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, 2011, PGE owned an electric transmission system consisting of approximately 730 circuit miles of 500-kV line and 360 circuit miles of 230-kV line. The Company also has approximately 24,000 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 Montana Intertie from the Colstrip plant in Montana to BPA's transmission system; and

- Approximately 19% of the California-Oregon AC Intertie (COI), a 4,800 MW transmission facility between John Day, in northern Oregon, and Malin, in southern Oregon near the California border.

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

- Approximately 3,100 MW of firm BPA transmission from remote resources and markets on BPA's system to PGE's service territory in Oregon;

- 200 MW of firm BPA transmission from mid-Columbia projects to the California-Oregon AC Intertie and 100 MW to the DC Intertie; and

- 100 MW of the Pacific DC Intertie between Celilo, Oregon and Sylmar, in southern California. These rights expire after June 30, 2012.

The California-Oregon AC Intertie and the Pacific DC Intertie are used primarily for the transmission of interstate purchases and sales of electricity among utilities, including PGE.

ITEM 3. 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 Docket Nos. DR 10, UE 88, and UM 989, Marion County Oregon Circuit Court, Case No. 94C-10417, the Court of Appeals of the State of Oregon, the Oregon Supreme Court, Case No. SC S45653.

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. Oral arguments were made on February 3, 2012 and a decision by the Oregon Court of Appeals remains pending.

Dreyer, Gearhart and Kafoury Bros., LLC v. Portland General Electric Company, Marion County Circuit Court, Case No. 03C 10639; and Morgan v. Portland General Electric Company, Marion County Circuit Court, Case No. 03C 10640.

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, Docket Nos. EL01-10-000, et seq., and Ninth Circuit Court of Appeals, Case No. 03-74139 (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

September 2001, upon completion of hearings, the appointed administrative law judge issued a recommended order that the claims for refunds be dismissed. In December 2002, the FERC re-opened the case to allow parties to conduct further discovery. In June 2003, the FERC issued an order terminating the proceeding and denying the claims for refunds. In November 2003 and February 2004, the FERC denied all requests for rehearing of its June 2003 decision. 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 its 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 it 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. Two requests for rehearing were filed with the court and, in April 2009, the Ninth Circuit issued an order that denied the requests for rehearing and 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. 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. 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, contesting, among other things, the applicable refund period reflected in the Order, the use of the *Mobile-Sierra* standard, any restraints in the Order on the type of evidence that could be introduced in the hearing, and the lack of market-wide remedy. The rehearing requests remain pending.

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. The settlement proceedings are ongoing.

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.

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 17, 2012, there were 1,105 holders of record of PGE's common stock and the closing sales price of PGE's common stock on that date was $25.14 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
2011			
Fourth Quarter	$ 25.54	$ 22.27	$ 0.265
Third Quarter	26.00	21.29	0.265
Second Quarter	26.05	23.30	0.265
First Quarter	24.00	21.64	0.260
2010			
Fourth Quarter	$ 22.65	$ 20.13	$ 0.260
Third Quarter	20.63	18.08	0.260
Second Quarter	20.60	18.10	0.260
First Quarter	20.66	17.46	0.255

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,				
	2011	2010	2009	2008	2007
	(In millions, except per share amounts)				
Statement of Income Data:					
Revenues, net	$ 1,813	$ 1,783	$ 1,804	$ 1,745	$ 1,743
Gross margin	58%	54%	48%	50%	50%
Income from operations	$ 309	$ 267	$ 208	$ 217	$ 269
Net income	147	121	89	87	145
Net income attributable to Portland General Electric Company	147	125	95	87	145
Earnings per share—basic and diluted	1.95	1.66	1.31	1.39	2.33
Dividends declared per common share	1.055	1.035	1.010	0.970	0.930
Statement of Cash Flows Data:					
Capital expenditures	300	450	696	383	455

	As of December 31,				
	2011	2010	2009	2008	2007
	(Dollars in millions)				
Balance Sheet Data:					
Total assets	$ 5,733	$ 5,491	$ 5,172	$ 4,889	$ 4,108
Total long-term debt	1,735	1,808	1,744	1,306	1,313
Total Portland General Electric Company shareholders' equity	1,663	1,592	1,542	1,354	1,316
Common equity ratio	48.6%	46.7%	46.9%	47.3%	50.0%

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 operations, business prospects, expected changes in 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;
- the effects of weak economies in the state of Oregon and the United States, including 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 can affect customer demand for power and could significantly affect 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 generation 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;
- volatility in wholesale power and natural gas prices, which could require the Company 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 and the availability and cost of capital, 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 costs, 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 generation facilities, in order to mitigate carbon dioxide, mercury and other gas emissions;
- changes in wholesale prices for natural gas, coal, oil, and other fuels and the impact of such changes on the Company's power costs and the availability and price of wholesale power in the western United States;
- 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 and the creditworthiness of customers and counterparties;
- the failure to complete capital projects on schedule and within budget;
- declines in the fair value of equity securities held by 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, information technology systems, or result in the release of confidential customer and proprietary information;
- employee workforce factors, including aging, potential strikes, work stoppages, and transitions in senior management;
- general 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, purchase, transmission, distribution, and retail sale of electricity in the state of Oregon, as well as the wholesale sale of electricity and natural gas in the United States and Canada. The Company generates revenues and cash flows primarily from the 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 the impacts of seasonal weather conditions on demand for electricity. Price changes and customer usage patterns (which can be affected by the economy) also have an effect on revenues while the availability and price of purchased power and fuel can affect income from operations. PGE is a winter-peaking utility that typically experiences its highest retail energy sales during the winter heating season, with a slightly lower peak in the summer that generally results from air conditioning demand.

Customers and Demand—Continued customer growth and significantly higher demand from a certain paper production customer during 2011 has resulted in a 3.3% increase in retail energy deliveries over 2010. Energy efficiency and conservation efforts by retail customers continue to influence total deliveries, although the financial effects of such efforts are intended to be mitigated by the decoupling mechanism. On a weather adjusted basis, retail energy deliveries in 2011 increased 1.4% compared to 2010, with 1% attributable to the paper production sector.

The following table indicates the average number of retail customers, including those customers who purchase their energy from an ESS, and deliveries, by customer class, during the past two years:

	2011		2010		Increase/ (Decrease) in Energy Deliveries
	Average Number of Customers	Energy Deliveries *	Average Number of Customers	Energy Deliveries *	
Residential	719,977	7,733	717,719	7,452	3.8%
Commercial	102,940	7,419	102,282	7,277	2.0
Industrial	255	4,193	265	4,004	4.7
Total	823,172	19,345	820,266	18,733	3.3%

* In thousands of MWh.

PGE projects that weather adjusted retail energy deliveries for 2012 will increase approximately 0.9% from 2011 weather adjusted levels, after allowing for energy efficiency and conservation efforts. Excluding certain paper production customers, PGE projects that retail energy deliveries for 2012 will increase approximately 1% to 1.5% from 2011 weather adjusted levels. One of these paper customers ceased operation early in 2011 and a second can purchase its incremental energy requirements based on market conditions, which can cause significant load volatility.

Average seasonally adjusted unemployment rates are as follows:

	United States	Oregon	Portland/ Salem
2011	9.0%	9.6%	9.6%
2010	9.6	10.6	10.5

The majority of the Company's service territory lies within the Portland/Salem metropolitan area. The state of Oregon, which continues to experience in-migration, forecasts that the average Oregon unemployment rate for 2012 is expected to be approximately 9.2%.

Power Operations—To meet the energy needs of its retail customers, the Company utilizes a combination of its own generating resources and wholesale market transactions. Based on numerous factors, including plant availability, customer demand, river flows, wind conditions, and current wholesale prices, PGE makes economic dispatch decisions continuously in an effort to obtain reasonably-priced power for its retail customers. In addition, PGE's thermal generating plants require varying levels of annual maintenance, during which the respective plant is unavailable to provide power. 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.

During the second quarters of 2011 and 2010, such annual maintenance was performed, with more extensive planned service maintenance completed in 2011 compared to 2010. Availability of the plants PGE operates approximated 93%, 95%, and 89% for the years ended December 31, 2011, 2010, and 2009, respectively, with the availability of Colstrip, which PGE does not operate, approximating 84%, 95%, and 68%, respectively. The decrease in Colstrip's availability in 2011 was due to the plant's planned maintenance, which included the installation of a new rotor for Unit 3.

During the year ended December 31, 2011, the Company's generating plants provided approximately 48% of its retail load requirement, compared to 64% in 2010 and 57% in 2009. Although the level of service maintenance on the Company's generating plants was greater in 2011 than in 2010, the decrease in the relative volume of power generated to meet the Company's retail load requirement was primarily due to the economic displacement of a significant amount of thermal generation by increased energy received from hydro resources and lower cost purchased power during 2011.

Energy received from PGE-owned hydroelectric plants and under contracts from mid-Columbia hydroelectric projects increased 14% in 2011 compared to 2010. These resources provided approximately 25% of the Company's retail load requirement for 2011, and 23% for 2010 and 25% for 2009. Energy received from these sources exceeded projections (or "normal") included in the Company's Annual Power Cost Update Tariff (AUT) by approximately 13% during 2011, compared to falling short of such projections by approximately 8% during 2010 and 2009. 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. Energy from hydro resources is expected to be below normal for 2012.

Energy expected to be received from wind generating resources is projected annually in the AUT and is based on wind studies completed in connection with the permitting process of the wind farm. 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 13% in 2011 and 27% in 2010.

Pursuant to the Company's power cost adjustment mechanism (PCAM), customer prices can be adjusted to reflect a portion of the difference between each year's forecasted net variable power costs (NVPC) included in prices (baseline NVPC) and actual NVPC for the year, to the extent such difference is outside of a pre-determined "deadband." The PCAM provides for 90% of actual NVPC above or below the deadband to be collected from or refunded to customers, respectively, subject to a regulated earnings test. Any estimated collection from or refund to customers pursuant to the PCAM is recorded in Revenues in the Company's statements of income in the period of accrual. Starting in 2011, the deadband ranges from $15 million below to $30 million above baseline NVPC.

For the year ended December 31, 2011, actual NVPC was approximately $34 million below baseline NVPC, which is $19 million below the lower deadband threshold. For 2011, PGE recorded an estimated refund to customers of approximately $10 million pursuant to the PCAM, reduced from the $17 million potential refund as the result of the regulated earnings test. For 2010, actual NVPC was approximately $12 million below baseline NVPC, with no refund to customers recorded as actual NVPC was within the established deadband range of $17 million below to $35 million above baseline NVPC. For 2009, actual NVPC was approximately $22 million above baseline NVPC, with no collection from customers recorded as actual NVPC was within the established deadband range of $15 million below to $29 million above baseline NVPC.

Capital Requirements and Financing—PGE's capital requirements in 2011 primarily 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. Included in such capital expenditures were the installation of the first of planned emissions controls at Boardman and the replacement of the cooling tower structure and upgrades to the gas turbine and exhaust system components at Coyote Springs during their annual maintenance outages. Capital expenditures were $300 million in 2011 and are expected to approximate $328 million in 2012.

Although there were no contractual maturities of long-term debt, PGE redeemed $73 million of long-term debt in 2011. Contractual maturities of long-term debt are $100 million in 2012.

During 2011, cash from operations of $453 million funded the Company's capital requirements and redemptions of long-term debt. For 2012, PGE expects to fund estimated capital requirements and contractual maturities of long-term debt with cash from operations, which is expected to approximate $500 million. For further information, see the Liquidity and Debt and Equity Financings sections of this Item 7.

In accordance with PGE's Integrated Resource Plan (IRP) and pursuant to the OPUC's competitive bidding guidelines, the Company plans to issue two RFPs for additional resources during 2012, with one for capacity and energy resources and another for renewable resources. The RFP for capacity and energy resources is expected to seek approximately 300 MW to 500 MW of base load energy resources, 200 MW of year-round flexible and peaking resources, 200 MW of bi-seasonal peaking supply, and 150 MW of winter-only peaking supply. The flexible and peaking resources are expected to be available in the 2013 to 2015 timeframe, with the base load energy resources expected to be available in the 2015 to 2017 timeframe. The RFP for renewable resources would seek approximately 101 MWa of renewable resources, which would be expected to be available to meet PGE's 2015 requirements under Oregon's renewable energy standard.

For additional information concerning PGE's IRP, see "Future Energy Resource Strategy" in the Power Supply section of Item 1.—"Business" and the Capital Requirements section in 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 2011, and some 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.

Retail revenue adjustments, as approved by the OPUC, became effective during 2011, pursuant to the processes or mechanisms described below:

- General Rate Case—Effective January 1, 2011, the OPUC approved an increase in PGE's annual revenues of $65 million, which represented an approximate 3.9% overall increase in customer prices, and included a reduction in power costs of $35 million under the AUT.

  The OPUC also approved a tariff that provides a mechanism for future consideration of customer price changes related to the recovery of the Company's remaining investment in the Boardman generating plant over a shortened operating life. The Company plans to cease coal-fired operation at Boardman at the end of 2020, consistent with revised rules adopted by the Oregon Environmental Quality Commission in December 2010 and approved by the EPA in June 2011.

  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 an updated decommissioning cost estimate, with new prices effective July 1, 2011, which provided an incremental revenue requirement for the last six months of 2011 of $7 million. The tariff provides for annual updates to the revenue requirements with revised prices to take effect each January 1.

- Power Costs—Pursuant to the AUT process, PGE annually files an estimate of its forecasted power costs, with new prices to become effective January 1st of 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. Effective January 1, 2012, rate adjustments under the AUT are estimated to reduce annual retail revenues by $22 million due to a reduction in power costs.

- 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 mechanism impacts results of operations only to the extent of providing a return on the Company's investments. It will, however, result in an increase in cash flows during future years to provide for the recovery of the initial capital expenditures for the renewable resources. The Company may submit a filing to the OPUC by April 1st each year, with prices 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.

  The Company did not submit a RAC filing in 2011, as it did not anticipate an approved renewable resource addition would be placed into service during the year.

- Decoupling Mechanism—The decoupling mechanism provides for customer collection or refund if weather adjusted use per customer is less than or more than that approved in the Company's most recent general rate case. In the Company's 2011 General Rate Case, the OPUC extended the mechanism through 2013.

  - In May 2010, the OPUC authorized the Company to refund to retail customers approximately $3 million related to the twelve month period ended January 31, 2010, as weather adjusted use per customer exceeded levels included in the 2009 General Rate Case. Revenues were adjusted during the corresponding period, while credits to customers began June 1, 2010 and continued over a one-year period.

  - In 2010, the Company recorded an estimated collection of $8 million, as weather adjusted use per customer was less than levels included in the 2009 General Rate Case. Collection from customers is to occur over a one-year period, which began June 1, 2011.

- During 2011, the Company recorded a $2 million refund to customers, which resulted primarily from slightly higher weather adjusted use per customer than that approved in the 2011 General Rate Case.

  Pending review and approval by the OPUC, any resulting refunds to customers would be expected over a one-year period beginning June 1, 2012.

- Refund of tax credits—In January 2011, PGE began providing credits to customers over a one year period for pollution control tax credits the Company had accumulated related to the Independent Spent Fuel Storage Installation (ISFSI). During 2011, the Company provided $18 million in customer credits.

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,					
	2011		2010		2009	
	Amount	As % of Rev	Amount	As % of Rev	Amount	As % of Rev
Revenues, net	$ 1,813	100%	$ 1,783	100%	$ 1,804	100%
Purchased power and fuel	760	42	829	46	944	52
Gross margin	1,053	58	954	54	860	48
Operating expenses:						
Production and distribution	201	11	174	10	178	10
Administrative and other	218	12	186	11	179	10
Depreciation and amortization	227	13	238	13	211	12
Taxes other than income taxes	98	5	89	5	84	4
Total operating expenses	744	41	687	39	652	36
Income from operations	309	17	267	15	208	12
Other income:						
Allowance for equity funds used during construction	5	—	13	1	18	1
Miscellaneous income, net	1	—	4	—	3	—
Other income, net	6	—	17	1	21	1
Interest expense	110	6	110	6	104	6
Income before income taxes	205	11	174	10	125	7
Income taxes	58	3	53	3	36	2
Net income	147	8	121	7	89	5
Less: net loss attributable to noncontrolling interests	—	—	(4)	—	(6)	—
Net income attributable to Portland General Electric Company	$ 147	8%	$ 125	7%	$ 95	5%

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

	Years Ended December 31,					
	2011		2010		2009	
Revenues[1] (dollars in millions):						
Retail:						
Residential	$ 877	48%	$ 803	45%	$ 856	47%
Commercial	635	35	601	34	642	36
Industrial	226	13	221	12	166	9
Subtotal	1,738	96	1,625	91	1,664	92
Other accrued revenues, net	(16)	(1)	39	2	(7)	—
Total retail revenues	1,722	95	1,664	93	1,657	92
Wholesale revenues	60	3	87	5	112	6
Other operating revenues	31	2	32	2	35	2
Total revenues	$ 1,813	100%	$ 1,783	100%	$ 1,804	100%
Energy deliveries[2] (MWh in thousands):						
Retail:						
Residential	7,733	36%	7,452	35%	7,901	36%
Commercial	7,419	35	7,277	34	7,559	34
Industrial	4,193	19	4,004	19	3,876	17
Total retail energy deliveries	19,345	90	18,733	88	19,336	87
Wholesale energy deliveries	2,142	10	2,580	12	2,896	13
Total energy deliveries	21,487	100%	21,313	100%	22,232	100%
Average number of retail customers:						
Residential	719,977	87%	717,719	88%	714,377	88%
Commercial	102,940	13	102,282	12	101,221	12
Industrial	255	—	265	—	271	—
Total	823,172	100%	820,266	100%	815,869	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,					
	2011		2010		2009	
Sources of energy (MWh in thousands):						
Generation:						
Thermal:						
Coal	4,125	19%	4,984	23%	3,760	18%
Natural gas	2,138	10	4,460	21	4,500	21
Total thermal	6,263	29	9,444	44	8,260	39
Hydro	1,933	9	1,830	9	1,800	8
Wind	1,216	6	833	4	499	2
Total generation	9,412	44	12,107	57	10,559	49
Purchased power:						
Term	6,252	29	3,984	19	6,145	29
Hydro	2,897	13	2,417	11	2,801	13
Wind	269	1	297	1	292	1
Spot	2,763	13	2,618	12	1,641	8
Total purchased power	12,181	56	9,316	43	10,879	51
Total system load	21,593	100%	21,423	100%	21,438	100%
Less: wholesale sales	(2,142)		(2,580)		(2,896)	
Retail load requirement	19,451		18,843		18,542	

Net income attributable to Portland General Electric Company for the year ended December 31, 2011 was $147 million, or $1.95 per diluted share, compared to $125 million, or $1.66 per diluted share, for the year ended December 31, 2010. The $22 million, or 18%, increase in net income was primarily due to the combined effects of a 3% increase in total retail energy deliveries, a 4% increase in customer prices, and a 9% decrease in average variable power cost. Decreased average variable power cost was driven by the economic displacement of a significant amount of thermal generation with lower cost purchased power and increased energy received from lower cost hydro and wind resources. As a result of decreased NVPC, PGE recorded an estimated refund to customers of $10 million pursuant to the PCAM, as actual NVPC was below baseline NVPC in 2011, with no refund or collection from customers recorded in 2010. Offsetting these increases to net income were higher employee-related costs.

Net income attributable to Portland General Electric Company for the year ended December 31, 2010 was $125 million, or $1.66 per diluted share, compared to $95 million, or $1.31 per diluted share, for the year ended December 31, 2009. The $30 million, or 32%, increase in net income was primarily due to the following:

- Improved power supply operations, resulting from increases in plant availability along with lower natural gas prices relative to those included in the AUT. Additionally, during 2009 approximately $16 million of incremental replacement power costs were incurred to replace the output of both Colstrip and Boardman during extended maintenance and repair outages;
- A $17 million increase in Other accrued revenues related to the regulatory treatment of income taxes (SB 408), which is primarily the result of a $13 million refund to customers recorded in 2009 and a $4 million reduction to that amount recorded in 2010. For 2009, taxes authorized for collection in customer prices exceeded the amount paid by PGE, resulting in a future refund to customers. For the tax year 2010, no amount related to SB 408 was recorded; and

- An $18 million decrease in Purchased power and fuel expense, related to the write-off in 2009 of previously deferred excess replacement power costs associated with Boardman's forced outage from late 2005 to early 2006.

2011 Compared to 2010

Revenues increased $30 million, or 2%, in 2011 compared to 2010 as a result of the net effect of the items discussed below.

Total retail revenues increased $58 million, or 3%, due primarily to the following items:

- A $62 million increase related to the volume of retail energy sold. Residential volumes were up 4%, primarily driven by cooler temperatures in the heating seasons. In addition, commercial and industrial deliveries were up 3% due largely to increased demand from the paper sector;
- A $61 million increase related to changes in average retail price that resulted primarily from the 3.9% overall increase effective January 1, 2011 authorized by the OPUC in the Company's 2011 General Rate Case and an increase effective July 1, 2011 related to the recovery of Boardman over a shortened operating life; partially offset by
- An $18 million decrease as a result of the ISFSI tax credits refund recorded in 2011 (offset in Depreciation and amortization), with no comparable refund in 2010;
- An $18 million decrease related to the deferral of revenue requirements for Biglow Canyon in 2010, which was included in Other accrued revenues. In 2011, the recovery of Biglow Canyon is included in the average retail price discussed above as a result of the 2011 General Rate Case;
- A $10 million decrease related to the decoupling mechanism, which is included in Other accrued revenues. In 2011, a $2 million refund to customers was recorded, which resulted primarily from slightly higher weather adjusted use per customer than that approved in the 2011 General Rate Case. Among other things, the 2011 General Rate Case reset the baseline used for the decoupling mechanism. An $8 million collection from customers was recorded in 2010, resulting from lower weather adjusted use per customer than that approved in the 2009 General Rate Case;
- A $10 million decrease related to an estimated refund to customers, pursuant to the PCAM, recorded in 2011 and included in Other accrued revenues, with no amount recorded in 2010. For further discussion of the PCAM, see Purchased power and fuel expense, below;
- A $7 million decrease related to the regulatory treatment of income taxes (SB 408) primarily due to an adjustment recorded in 2010 that pertained to the 2009 liability, which was included in Other accrued revenues. SB 408 was repealed in 2011 and no longer applies to tax years after 2009; and
- A $5 million decrease due to the 2010 reversal of a deferral for customer refunds pursuant to an OPUC order related to the 2005 Oregon Corporate Tax Kicker, which was included in Other accrued revenues.

Heating degree-days in 2011 were 10% greater than the 15-year average and increased 11% compared to 2010, while cooling degree-days increased 15% from 2010. The following table indicates the number of heating and cooling degree-days for the periods presented, along with 15-year averages provided by the National Weather Service, as measured at Portland International Airport and illustrates that weather effects increased the demand for electricity in 2011 over 2010:

	Heating Degree-Days		Cooling Degree-Days	
	2011	2010	2011	2010
1st Quarter	1,974	1,629	—	—
2nd Quarter	946	861	16	18
3rd Quarter	51	117	346	296
4th Quarter	1,679	1,580	—	—
Full Year	4,650	4,187	362	314
15-year Full Year average	4,219	4,192	464	473

On a weather adjusted basis, retail energy deliveries in 2011 increased 1.4% compared to 2010, with 1% attributable to the paper production sector. Deliveries to residential, commercial, and industrial customers increased by 0.2%, 0.4%, and 5.3%, respectively.

PGE projects that weather adjusted retail energy deliveries for 2012 will increase approximately 0.9% from 2011 weather adjusted levels, after allowing for energy efficiency and conservation efforts. Excluding certain paper production customers, PGE projects that retail energy deliveries for 2012 will increase approximately 1% to 1.5% from 2011 weather adjusted levels. One of these paper customers ceased operation early in 2011 and a second can purchase its incremental energy requirements based on market conditions, which can cause significant load volatility.

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.

Wholesale revenues in 2011 decreased $27 million, or 31%, from 2010 as a result of the following:

- A $13 million decrease related to a 17% decline in the average wholesale price the Company received, driven by lower electricity market prices due to abundant hydro in the region; and
- A $14 million decrease due to a 17% decline in wholesale energy sales volume.

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 2011, Purchased power and fuel expense decreased $69 million, or 8%, from 2010, with $75 million related to a 9% decrease in average variable power cost, partially offset by $7 million related to a 1% increase in total system load. The average variable power cost was $35.15 per MWh in 2011 compared to $38.68 per MWh in 2010.

The decrease in Purchased power and fuel expense consisted of:

- A $71 million decrease in the cost of generation, primarily driven by a decrease in the proportion of power provided by Company-owned thermal generating resources. During 2011, a significant amount of thermal generation was economically displaced by lower cost purchased power and increased energy received from lower cost hydro and wind generating resources, relative to 2010. The average cost of power generated increased 1% in 2011 compared to 2010; and

- A $2 million increase in the cost of purchased power, consisting of $151 million related to a 31% increase in purchases, substantially offset by $149 million related to a 23% decrease in average cost. The decrease in average cost was primarily driven by lower wholesale power prices resulting from favorable hydro conditions.

Energy from PGE-owned wind generating resources (Biglow Canyon) increased 46% from 2010, and represented 6% of the Company's retail load requirement in 2011 compared to 4% in 2010. These increases were due to the completion of the third and final phase of Biglow Canyon in August 2010 and favorable wind conditions in 2011 relative to 2010. Energy received from wind generating resources fell short of projections included in the Company's AUT by approximately 13% in 2011 and 27% in 2010.

Hydroelectric energy during 2011, from both PGE-owned hydroelectric projects and from mid-Columbia projects, exceeded that projected in the Company's 2011 AUT and 2010 by 13% and 14%, respectively. Total hydroelectric energy fell short of projections included in the Company's AUT by approximately 8% in 2010. Current forecasts indicate that regional hydro conditions in 2012 will be below normal levels.

The following table indicates the forecast of the April-to-September 2012 runoff (issued February 21, 2012) compared to the actual runoffs for 2011 and 2010 (as a percentage of normal, as measured over the 30-year period from 1971 through 2000):

	Runoff as a Percent of Normal *		
Location	2012 Forecast	2011 Actual	2010 Actual
Columbia River at The Dalles, Oregon	95%	135%	79%
Mid-Columbia River at Grand Coulee, Washington	99	123	78
Clackamas River at Estacada, Oregon	92	135	124
Deschutes River at Moody, Oregon	98	120	104

* 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.

For 2011, actual NVPC was approximately $34 million below baseline NVPC, with PGE recording an estimated refund to customers of approximately $10 million pursuant to the PCAM, which was reduced from the potential refund of $17 million as a result of the regulated earnings test. Actual NVPC was approximately $12 million below baseline NVPC in 2010, but within the established deadband ranges; accordingly, no refund to customers was recorded pursuant to the PCAM.

Gross margin, which represents the difference between Revenues and Purchased power and fuel expense, is among those performance indicators utilized by management in the analysis of financial and operating results and is intended to supplement the understanding of PGE's operating performance. It provides a measure of income available to support other operating activities and expenses of the Company and serves as a useful measure for understanding and analyzing changes in operating performance between reporting periods. It is considered a "non-GAAP financial measure," as defined in accordance with SEC rules, and is not intended to replace operating income as determined in accordance with GAAP.

As a percent of Revenues, Gross margin was 58% in 2011 compared to 54% in 2010. The increase in Gross margin was driven by the 9% decrease in average variable power cost and increases of 3% in retail energy deliveries and 4% in retail customer prices resulting from the 2011 General Rate Case, which became effective January 1, 2011, and a tariff for the recovery of Boardman over a shortened operating life, which became effective July 1, 2011.

Production and distribution expense increased $27 million, or 16%, in 2011 compared to 2010, primarily due to the following:

- A $10 million increase due to increased operating and maintenance expenses at the Company's thermal generating plants (including extensive work performed during their planned annual outages) and at Biglow Canyon, the final phase of which was completed in August 2010;
- A $9 million increase to distribution system expenses primarily related to increased information technology costs and tree trimming activities; and
- An $8 million increase related to higher labor and employee benefit costs.

Administrative and other expense increased $32 million, or 17%, in 2011 compared to 2010, primarily due to the following:

- A $13 million increase primarily due to higher pension and employee benefit expenses, and increased incentive compensation related to an improvement in corporate financial and operating performance for 2011;
- A $5 million increase related to higher information technology costs;
- A $4 million increase in fees related to various legal and environmental proceedings;
- A $3 million increase in the provision and write-off of certain uncollectible customer accounts; and
- A $2 million increase related to higher OPUC regulatory fees resulting from higher prices in 2011 (fully offset in Retail revenues).

Depreciation and amortization expense decreased $11 million, or 5%, in 2011 compared to 2010, due largely to the net effect of the following:

- An $18 million decrease related to the amortization of customer refunds for the ISFSI tax credits (offset in Revenues);
- A $12 million decrease related to increases in estimated useful lives and reductions to estimated removal costs of certain long-lived assets due to an updated depreciation study;
- A $4 million decrease related to the impairment loss recognized in 2010 on photovoltaic solar power facilities, the majority of which was allocated to noncontrolling interest through the Net loss attributable to the noncontrolling interests. For additional information, see Note 16, Variable Interest Entities, in the Notes to Consolidated Financial Statements included in Item 8.—"Financial Statements and Supplementary Data."; offset by
- A $21 million increase in depreciation related to the completion of Biglow Canyon Phase III in August 2010, Boardman shortened operating life, the Smart Meter project, and other capital additions in late 2010 and in 2011; and
- A $2 million increase in amortization related to hydroelectric licenses.

Taxes other than income taxes increased $9 million, or 10%, in 2011 compared to 2010, primarily due to higher property taxes, resulting from both increased property values and tax rates, and higher city franchise fees related to increased Retail revenues.

Other income, net was $6 million in 2011 compared to $17 million in 2010. The decrease is primarily due to the following:

- An $8 million decrease in the allowance for equity funds used during construction, as a result of lower construction work in progress balances during 2011, related primarily to the August 2010 completion of Biglow Canyon Phase III; and
- A $5 million decrease in income from non-qualified benefit plan trust assets, resulting from a minimal loss in the fair value of the plan assets in 2011 compared to a $5 million gain in 2010.

Interest expense in 2011 was comparable to 2010, as a $6 million decrease in the allowance for funds used during construction, related primarily to the August 2010 completion of Biglow Canyon Phase III, was offset by lower interest on long-term debt and certain regulatory liabilities.

Income taxes increased $5 million, or 9%, in 2011, compared to 2010, primarily due to higher income before taxes in 2011, partially offset by increased federal wind production tax credits (PTCs) in that year. The effective tax rates (28.3% and 30.3% for 2011 and 2010, respectively) differ from the federal statutory rate primarily due to benefits from PTCs and state tax credits. An increase in PTCs, related to increased production from the completed Biglow Canyon wind project, was partially offset by an increase in the state income tax rate and a reduction in state tax credits.

Net loss attributable to noncontrolling interests represents the noncontrolling interests' portion of the net loss of PGE's less-than-wholly-owned subsidiaries, the majority of which in 2010 consists of the impairment losses recognized on the photovoltaic solar power facilities, discussed previously in Depreciation and amortization.

2010 Compared to 2009

Revenues decreased $21 million, or 1%, in 2010 compared to 2009 as a result of the net effect of the items discussed below.

Total retail revenues increased $7 million, or 1%, due primarily to net effect of the following:

- A $25 million increase related to the volume of retail energy sold resulting from the net effect of:
  - A shift in the mix of customers purchasing their energy requirements from PGE, with a certain large industrial customer choosing to purchase it energy requirements from PGE as opposed to purchasing its energy requirements from an ESS in 2009;
  - A 3.3% increase in deliveries to industrial customers due in part to improvement in the high technology sector and an increase in production by one large industrial customer; and
  - The addition of an average of 4,400 retail customers; partially offset by
  - A 5.7% decrease in residential deliveries and a 3.7% decrease in commercial deliveries primarily due to milder weather conditions during 2010 and the continued effects of a weak economy; and
  - The effects of energy efficiency programs on retail energy deliveries during 2010 relative to 2009;
- A $17 million increase related to SB 408, included in Other accrued revenues, resulting from an estimated $13 million customer refund recorded in 2009 along with a $4 million reversal of a portion of the 2009 refund recorded in 2010. As a result of the uncertainty around the application of the rules at the time, the Company recorded no collection from customers for 2010;
- A $15 million increase related to the decoupling mechanism, which is included in Other accrued revenues. In 2010, an estimated $8 million receivable from customers was recorded, resulting from lower weather adjusted use per customer than that approved in the 2009 General Rate Case, compared to a $7 million refund to customers recorded in 2009, resulting from higher weather adjusted use per customer than that approved in the 2009 General Rate Case;

- A $10 million increase resulting from a reduction in the transition adjustment credit provided to those commercial and industrial customers that purchase power from ESSs. Transition adjustment credits reflect the difference between the cost and market value of PGE's power supply, as provided by Oregon's electricity restructuring law;
- A $7 million increase related to the deferral of revenue requirements for Biglow Canyon, which is included in Other accrued revenues;
- A $5 million increase due to the reversal of a deferral for customer refunds related to the 2005 Oregon Corporate Tax Kicker, pursuant to an OPUC order issued in the third quarter of 2010, which is included in Other accrued revenues; and
- A $72 million decrease related to a 4% decline in average retail price that resulted primarily from a decrease in net variable power costs, partially offset by increases for the recovery of Biglow Canyon Phase II and Selective Water Withdrawal capital projects.

Heating degree-days in 2010 decreased 5% compared to 2009, while cooling degree-days, which were 34% less than the15-year average, decreased 50%. The following table indicates the number of heating and cooling degree-days for the periods presented, along with 15-year averages provided by the National Weather Service, as measured at Portland International Airport:

	Heating Degree-Days		Cooling Degree-Days	
	2010	**2009**	**2010**	**2009**
1st Quarter	1,629	2,022	—	—
2nd Quarter	861	578	18	90
3rd Quarter	117	63	296	537
4th Quarter	1,580	1,728	—	—
Full Year	4,187	4,391	314	627
15-year Full Year average	4,192	4,169	473	467

On a weather adjusted basis, retail energy deliveries decreased 1.4% in 2010 compared to 2009, with deliveries to residential and commercial customers decreasing by 2.5%, and 2.2%, respectively, and deliveries to industrial customers increasing by 2.3%.

Wholesale revenues in 2010 decreased $25 million, or 22%, from 2009 as a result of the following:

- A $13 million decrease related to a 12% decline in average wholesale prices obtained by the Company, driven by lower electricity market prices; and
- A $12 million decrease due to an 11% decline in wholesale energy sales volume.

In 2010, electricity demand from PGE's retail customers was less than originally projected, with excess power, initially acquired to meet retail load, sold into a relatively low-priced wholesale market. A portion of the excess volume was used to offset lower than projected hydro and wind production, reducing the volume available for resale into the wholesale energy market.

Other operating revenues decreased $3 million, or 9%, primarily due to a reduction in fuel oil sales from the Company's Beaver generating plant. Such sales were $5 million in 2010 and $8 million in 2009.

Purchased power and fuel expense decreased $115 million, or 12%, for 2010 from 2009, primarily due to an 11% decrease in average variable power cost, which was largely driven by the shift in the mix of energy sources. The average variable power cost was $38.68 per MWh in 2010 and $43.22 per MWh in 2009. The average variable power cost for 2009 excludes the effect of the write-off of the regulatory asset discussed below.

The decrease in Purchased power and fuel consisted of:

- A $96 million decrease in the cost of purchased power, consisting of $84 million related to a 14% decrease in purchases and $12 million related to a 2% decrease in average cost. Increased purchases were required in 2009 to replace the output of Colstrip and Boardman during extended outages at these plants, resulting in incremental replacement power costs of approximately $16 million;
- An $18 million decrease related to the write-off in 2009 of a portion of a regulatory asset representing deferred excess replacement power costs associated with Boardman's forced outage from late 2005 to early 2006; and
- A $2 million decrease in the cost of generation, consisting of $52 million related to a 13% decrease in average cost, substantially offset by $50 million related to a 15% increase in generation, resulting primarily from a 33% increase in generation at Colstrip and Boardman. In 2009, both Colstrip and Boardman had extended repair and maintenance outages. The decrease in average cost was primarily due to a 6% decrease in the average cost of natural gas-fired generation, which was driven by decreases in natural gas prices.

Energy received from PGE-owned hydroelectric plants and under contracts from mid-Columbia projects in 2010 were up 2% and down 14%, respectively, from 2009. Additionally, energy received from hydroelectric resources also fell short of projections included in the Company's AUT by approximately 8% in 2010 and 2009.

Gross margin was 54% in 2010 compared to 48% in 2009, an increase of 13%. Contributing to the increase was the impact of improved thermal operations, which more than offset the effect of lower retail energy sales during the year. Also contributing to the increase was the impact of SB 408 and the write-off of deferred power costs related to Boardman's outage, which had negative impacts on Gross margin in 2009.

Production and distribution expense decreased $4 million, or 2%, in 2010 compared to 2009, due to the net effect of the following:

- A $6 million decrease related to certain capital costs expensed in 2009 for the Selective Water Withdrawal project, pursuant to a stipulation with the OPUC;
- A $5 million decrease in repair and restoration expenses, related primarily to 2009 wind storms;
- A $5 million decrease in operating and maintenance expenses at the Company's thermal generating plants;
- A $2 million decrease related to a reserve established in 2009 for the cost of certain environmental remediation activities; and offset by
- A $7 million increase related to the deferral of certain plant maintenance costs at Boardman, Beaver, and Colstrip in 2009. As authorized by the OPUC in PGE's 2009 General Rate Case, certain maintenance costs that exceed those covered in current prices are deferred and amortized over ten years, beginning in 2009; and
- A $7 million increase in operating and maintenance expenses related to the Company's distribution system and Biglow Canyon.

Administrative and other expense increased $7 million, or 4%, in 2010 compared to 2009, due to the following:

- A $5 million increase in incentive compensation, related to improved corporate financial and operating performance in 2010;
- A $5 million increase in legal expenses and reserves for asserted claims;
- A $5 million increase in employee benefit expenses, related primarily to higher pension and health care costs; and offset by
- A $3 million decrease in the provision for uncollectible accounts, due to an improvement in the status of customer accounts;
- A $3 million decrease in insurance costs and in customer support expenses, including reductions related to

implementation of the smart meter project; and

- A $2 million decrease related to OPUC revenue fees (fully offset in Retail revenues).

Depreciation and amortization expense increased $27 million, or 13%, in 2010 compared to 2009, due largely to the net effect of the following:

- A $23 million increase in depreciation related to Biglow Canyon Phases II and III, the smart meter project, the Selective Water Withdrawal project, and other capital additions in late 2009 and 2010;
- A $4 million increase related to a 2009 reduction in the deferral of certain Oregon tax credits for future ratemaking treatment, as the Company was unable to utilize such credits (offset in Income taxes);
- A $2 million increase related to the amortization of certain regulatory assets and liabilities; and offset by
- A $1 million decrease related to lower impairment losses recognized in 2010 compared to 2009 on photovoltaic solar power facilities, the majority of which was allocated to noncontrolling interests through the Net loss attributable to the noncontrolling interests. For additional information, see Note 16, Variable Interest Entities, in the Notes to Consolidated Financial Statements included in Item 8.—"Financial Statements and Supplementary Data."

Taxes other than income taxes increased $5 million, or 6%, in 2010 compared to 2009, due primarily to higher property and payroll taxes, as well as higher city franchise fees.

Other income, net was $17 million in 2010 compared to $21 million in 2009. The decrease was due primarily to the net effect of the following:

- A $5 million decrease in the allowance for equity funds used during construction, as a result of lower construction work in progress balances during 2010, related primarily to the completion of Biglow Canyon Phases II and III;
- A $4 million decrease in income from non-qualified benefit plan trust assets, resulting from a $5 million increase in the fair value of the plan assets during 2010 compared to a $9 million increase in 2009; and offset by
- A $4 million increase resulting from reductions in corporate donations, sponsorships, and certain non-utility activities, partially offset by lower interest income on regulatory assets.

Interest expense increased $6 million, or 6%, in 2010 compared to 2009, primarily due to the net effect of the following:

- An $8 million increase resulting from a higher average long-term debt balance during 2010 compared to 2009, related primarily to issuances of first mortgage bonds in late 2009 and 2010 to fund the construction of new generating facilities. In 2010, the average balance of long-term debt outstanding was $1,776 million compared to $1,525 million in 2009;
- A $3 million increase resulting from a decrease in the allowance for funds used during construction, related primarily to the completion of the construction of Biglow Canyon Phases II and III; and offset by
- A $5 million decrease in interest on regulatory liabilities, consisting primarily of customer refunds related to the Trojan regulatory proceeding and the Company's PCAM.

Income taxes increased $17 million, or 47%, in 2010 compared to 2009, primarily due to higher income before taxes in 2010. The effective tax rates (30.3% in 2010 and 28.8% in 2009) differ from the federal statutory rate primarily due to benefits from federal wind production tax credits (PTCs) and state tax credits. An increase in PTCs, related to increased production from the completed Biglow Canyon wind farm, was largely offset by an increase in the state income tax rate and a reduction in state tax credits.

Net loss attributable to noncontrolling interests of $4 million in 2010 and $6 million in 2009 represents the noncontrolling interests' portion of the net loss of PGE's less-than-wholly-owned subsidiaries, the majority of which consists of the impairment losses recognized on the photovoltaic solar power facilities, discussed previously in

Depreciation and amortization.

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 2011 and future debt maturities and projected cash requirements for 2012 through 2016 for projects that the Board of Directors has approved (in millions, excluding AFDC):

	Years Ending December 31,					
	2011	2012	2013	2014	2015	2016
Ongoing capital expenditures	$ 259	$ 266	$ 249	$ 231	$ 251	$ 330
Hydro licensing and construction	16	24	12	29	31	15
Boardman emissions controls (1)	17	11	12	—	—	—
Cascade Crossing	13	27	4	—	—	—
Total capital expenditures	$ 305 (2)	$ 328	$ 277	$ 260	$ 282	$ 345
Long-term debt maturities	$ 73	$ 100	$ 100	$ —	$ 70	$ 67

(1) Represents 80% of estimated total costs based on installation of controls to meet regulatory requirements. In 1985, PGE sold an undivided 15% interest in Boardman to a third party, reducing the Company's ownership interest from 80% to 65%. The purchaser has certain rights to participate in the financing of the portion of the total capital cost attributable to its interest. If the purchaser does not exercise its rights to finance the portion of the total cost attributable to its interest, PGE's share of the total cost for the emissions controls at Boardman is expected to be 80%. PGE would seek to recover the incremental investment in future customer prices, although there can be no guarantee such recovery would be granted.

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

The following provides information regarding the items presented in the table above.

Ongoing capital expenditures—Consists of upgrades to and replacement of transmission, distribution and generation infrastructure, as well as new customer connections. Preliminary engineering costs, which consist of expenditures for preliminary surveys, plans, and investigations made for the purpose of determining the feasibility of utility projects, including certain projects discussed in the *Integrated Resource Plan* section below, are included in Ongoing capital expenditures and amounted to $3 million in 2011. The Company expects that it will spend approximately $2 million on Preliminary engineering in 2012.

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.

Boardman emissions controls—In June 2011, the EPA approved revised rules that established new emissions limits at Boardman and provide for coal-fired operation at Boardman to cease no later than December 31, 2020.

The emissions limits imposed under the revised rules have required the addition of certain controls. The Company's portion of capital spending on the Boardman emissions controls to date is approximately $22 million. The amount of anticipated future expenditures is reflected in the table above.

Integrated resource plan—The Company's IRP, acknowledged by the OPUC in November 2010, included the following resource, capacity, and transmission projects:

- The addition of new generating resources and improvements to existing plants. The related RFP processes will determine the successful bidders for the new capacity, energy, and renewable resources described in the IRP and clarify the timing and total cost; and
- The construction of Cascade Crossing at an estimated total cost (in 2011 dollars) of $800 million to $1.0 billion. The Company continues to work with other stakeholders in planning the project and potential project partnerships.

Due to the uncertainty of these projects, the Capital Requirements table above does not include estimates for any amounts related to these projects beyond 2012. Certain costs related to investigating the potential construction of these facilities are currently included in *Ongoing capital expenditures* in the table above. For further information on the Company's IRP and the projects subject to the RFP process, see Capital Requirements and Financing in the Overview section of this Item 2, as well as the Future Energy Resource Strategy section of Power Supply and Transmission and Distribution contained in Item 1.—Business.

Liquidity

PGE's access to short-term debt markets, including revolving credit from banks, helps provide necessary liquidity to support the Company's current 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,		
	2011	**2010**	**2009**
Cash and cash equivalents, beginning of year	$ 4	$ 31	$ 10
Net cash provided by (used in):			
Operating activities	453	391	386
Investing activities	(299)	(430)	(700)
Financing activities	(152)	12	335
Net change in cash and cash equivalents	2	(27)	21
Cash and cash equivalents, end of year	$ 6	$ 4	$ 31

2011 Compared to 2010

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, included in net income during a given period. The $62 million increase in cash provided by operating activities in 2011 compared to 2010 was largely due to an increase in net income after the consideration of non-cash items, as well as a decrease in margin deposit requirements pursuant to certain power and natural gas purchase and sale agreements. Such increases were partially offset by a $44 million decrease in the income tax refunds received in 2011 compared to 2010 and a $16 million contribution to the voluntary employees' beneficiary association trusts (VEBAs) in 2011. The VEBAs fund the benefits of the Company's non-contributory postretirement health and life insurance plans.

A significant portion of cash provided by operations consists of recovery in customer prices of non-cash charges for depreciation and amortization. The Company estimates that such charges will approximate $250 million in 2012. Combined with all other sources, cash provided by operations is estimated to be approximately $500 million in 2012. This estimate includes the return of $30 million of margin deposits held by brokers as of December 31, 2011, and is based on both the timing of contract settlements and projected energy prices. The remaining $220 million in estimated cash flows from operations in 2012 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. Capital expenditures decreased $150 million in 2011 compared to 2010 due to decreased construction costs related to the completion of Biglow Canyon Phase III in August 2010, as well as a $19 million distribution from the Nuclear decommissioning trust to PGE in 2010.

The Company plans approximately $328 million of capital expenditures in 2012 related to hydro licensing and construction, Boardman emissions controls and ongoing capital expenditures related to upgrades to and replacement of transmission, distribution and generation infrastructure. PGE plans to fund the 2012 capital expenditures with the cash expected to be generated from operations during 2012, as discussed above. For additional information, see the Capital Requirements 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 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. During 2010, net cash provided by financing activities primarily consisted of proceeds received from the issuance or remarketing of long-term debt of $249 million, net issuances of commercial paper of $19 million and noncontrolling interests' capital contributions of $10 million, partially offset by the repayment of long-term debt of $186 million and the payment of dividends of $78 million.

2010 Compared to 2009

Cash Flows from Operating Activities—The $5 million increase in cash provided by operating activities in 2010 compared to 2009 was primarily due to an increase in net income after the consideration of noncash items, the receipt of an income tax refund in 2010 that was accrued in 2009, and customer refunds in 2009 related to the Trojan regulatory proceeding. These increases were offset by an increase in margin deposit requirements pursuant to power and natural gas purchase agreements, driven by decreases in the forward market prices of power and natural gas, and a $30 million contribution to the pension plan in 2010.

Cash Flows from Investing Activities—Capital expenditures decreased $246 million in 2010 from 2009 primarily due to decreased construction costs related to Biglow Canyon and the smart meter project, as well as a decrease in construction costs related to the Selective Water Withdrawal project, which was completed in January 2010. Additionally, during 2010, a $19 million distribution was made from the Nuclear decommissioning trust to PGE.

Cash Flows from Financing Activities—During 2010, net cash provided by financing activities primarily consisted of proceeds received from the issuance or remarketing of long-term debt of $249 million and net issuances of commercial paper of $19 million, partially offset by the repayment of long-term debt of $186 million and the payment of dividends of $78 million. During 2009, net cash provided by financing activities consisted of issuances of long-term debt of $580 million and common stock of $170 million, partially offset by the repayment of long-term debt of $142 million, net repayment of amounts due under revolving lines of credit of $131 million, the payment of dividends of $72 million and net maturities of commercial paper of $65 million.

Dividends on Common Stock

The following table indicates common stock dividends declared in 2011:

Declaration Date	Record Date	Payment Date	Declared Per Common Share
February 16, 2011	March 25, 2011	April 15, 2011	$ 0.260
May 11, 2011	June 24, 2011	July 15, 2011	0.265
August 3, 2011	September 26, 2011	October 17, 2011	0.265
October 26, 2011	December 27, 2011	January 17, 2012	0.265

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.

On February 22, 2012, the Board of Directors declared a dividend of $0.265 per share of common stock to stockholders of record on March 26, 2012, payable on or before April 16, 2012.

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	A3	A-
Senior unsecured debt	Baa2	BBB
Commercial paper	Prime-2	A-2
Outlook	Stable	Stable

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 related 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, 2011, PGE had posted approximately $184 million of collateral with these counterparties, consisting of $80 million in cash and $104 million in letters of credit, $26 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, 2011, the approximate amount of additional collateral that could be requested upon a single agency downgrade to below investment grade is approximately $142 million and decreases to approximately $49 million by December 31, 2012. The amount of additional collateral that could be requested upon a dual agency downgrade to below investment grade is approximately $337 million and decreases to approximately $128 million by December 31, 2012.

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 First Mortgage Bonds 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, 2011, under the most restrictive issuance test in the Indenture of Mortgage and Deed of Trust, the Company could have issued up to approximately $579 million of additional First Mortgage Bonds. Any issuances of First Mortgage Bonds 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 ratio). As of December 31, 2011, the Company’s debt ratio, as calculated under the credit agreements, was 51.5%.

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. However, the Company’s ability to issue long-term debt and equity could be adversely affected by changes in capital market conditions. PGE currently does not expect to issue debt or equity securities in 2012.

Short-term Debt. PGE has approval from the FERC to issue short-term debt up to a total of $700 million through February 6, 2014 and currently has the following unsecured revolving credit facilities:

- A $370 million syndicated credit facility, with $10 million and $360 million scheduled to terminate in July 2012 and July 2013, respectively; and
- A $300 million syndicated credit facility, which is scheduled to terminate in December 2016.

These credit facilities supplement operating cash flows and provide a primary source of liquidity. Pursuant to the terms of the agreements, the credit facilities may be used for general corporate purposes, as a backup for commercial paper borrowings, and the issuance of standby letters of credit. As of December 31, 2011, PGE had no borrowings outstanding under the credit facilities, with $30 million of commercial paper outstanding and $124 million of letters of credit issued. As of December 31, 2011, the aggregate unused available credit under the credit facilities was $516 million.

Long-term Debt. In 2011, PGE redeemed $10 million of Pollution Control Revenue Bonds in January and $63 million of 6.5% Series First Mortgage Bonds in December, both of which were scheduled to mature in 2014, with no issuances of long-term debt. As of December 31, 2011, total long-term debt outstanding was $1,735 million. PGE owns $21 million of its Pollution Control Revenue Bonds, which may be remarketed at a later date, at the Company’s option, through 2033.

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. The Company 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. PGE's common equity ratios were 48.6% and 46.7% as of December 31, 2011 and 2010, respectively.

Contractual Obligations and Commercial Commitments

The following indicates PGE's contractual obligations as of December 31, 2011 (in millions):

	2012	2013	2014	2015	2016	There-after	Total
Long-term debt	$ 100	$ 100	$ —	$ 70	$ 67	$1,398	$1,735
Interest on long-term debt (1)	99	92	89	87	83	1,106	1,556
Capital and other purchase commitments	58	18	10	10	6	73	175
Purchased power and fuel:							
Electricity purchases	129	77	76	76	57	381	796
Capacity contracts	21	21	21	20	19	—	102
Public Utility Districts	7	8	8	8	7	30	68
Natural gas	49	22	22	20	12	11	136
Coal and transportation	25	19	9	—	—	—	53
Pension plan contributions (2)	—	25	35	34	32	11	137
Operating leases	9	10	9	10	10	196	244
Total	$ 497	$ 392	$ 279	$ 335	$ 293	$3,206	$5,002

(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, 2011.

(2) Contributions to the Company's pension plan are estimated based on numerous plan assumptions, including plan funded status. A return on plan assets of 8.25% and a discount rate of 5.0% was used for all periods presented.

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

PGE has no 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 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 asset retirement obligations (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 sheets, 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 material loss contingency is accrued and disclosed 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, 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 either Net income or Other comprehensive 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 the plan include the discount rate, the expected return on plan assets, mortality rates, and wage escalation. These assumptions are evaluated by PGE, 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 projected long-term return on assets in the plan investment portfolio.

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, individually, have the effect of increasing the 2011 net periodic pension expense by approximately $1 million.

Fair Value Measurements

In accordance with accounting and reporting requirements, PGE applies fair value measurements to its financial assets and liabilities. Fair value is 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, 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 the Company'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; swap 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.

For purposes of disclosure, the Company has historically used value at risk measures. However, PGE believes that tabular presentation of expected cash flows related to these market-risk sensitive instruments provides more meaningful information.

The following table presents energy commodity derivative fair values as a net liability as of December 31, 2011 that are expected to settle in each respective year (in millions):

	2012	2013	2014	2015	Total
Commodity contracts:					
Electricity	$ 64	$ 42	$ 21	$ 8	$ 135
Natural gas	132	72	24	6	234
	$ 196	$ 114	$ 45	$ 14	$ 369

The following table presents energy commodity derivative fair values as a net liability as of December 31, 2010 that were expected to settle in each respective year (in millions):

	2011	2012	2013	2014	Total
Commodity contracts:					
Electricity	$ 73	$ 25	$ 11	$ 5	$ 114
Natural gas	102	92	43	9	246
	$ 175	$ 117	$ 54	$ 14	$ 360

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, 2011, a 10% change in the value of the Canadian dollar would result in an immaterial change in income before income taxes for transactions that will settle over the next 12 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, 2011, PGE had no borrowings outstanding under its revolving credit facilities and $30 million of 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, 2011, 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	2012	2013	2014	2015	2016	There-after
First Mortgage Bonds	$ 1,962	$ 1,614	$ 100	$ 100	$ —	$ 70	$ 67	$ 1,277
Pollution Control Revenue Bonds	129	121	—	—	—	—	—	121
Total	$ 2,091	$ 1,735	$ 100	$ 100	$ —	$ 70	$ 67	$ 1,398

As of December 31, 2011, 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, 2011, PGE's credit risk exposure is $1 million for commodity activities with externally-rated investment grade counterparties and matures in 2012. 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.

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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, 2011 and 2010, 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, 2011. We also have audited the Company's internal control over financial reporting as of December 31, 2011, based on criteria established in *Internal Control-Integrated Framework* 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, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, 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, 2011, based on the criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 23, 2012

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

	Years Ended December 31,		
	2011	2010	2009
Revenues, net	$ 1,813	$ 1,783	$ 1,804
Operating expenses:			
Purchased power and fuel	760	829	944
Production and distribution	201	174	178
Administrative and other	218	186	179
Depreciation and amortization	227	238	211
Taxes other than income taxes	98	89	84
Total operating expenses	1,504	1,516	1,596
Income from operations	309	267	208
Other income:			
Allowance for equity funds used during construction	5	13	18
Miscellaneous income, net	1	4	3
Other income, net	6	17	21
Interest expense	110	110	104
Income before income taxes	205	174	125
Income taxes	58	53	36
Net income	147	121	89
Less: net loss attributable to noncontrolling interests	—	(4)	(6)
Net income attributable to Portland General Electric Company	$ 147	$ 125	$ 95
Weighted-average shares outstanding (in thousands):			
Basic	75,333	75,275	72,790
Diluted	75,350	75,291	72,852
Earnings per share—basic and diluted	$ 1.95	$ 1.66	$ 1.31
Dividends declared per common share	$ 1.055	$ 1.035	$ 1.010

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions)

	Years Ended December 31,		
	2011	2010	2009
Net income	$ 147	$ 121	$ 89
Other comprehensive income (loss)—Change in compensation retirement benefits liability and amortization, net of taxes of $1 in 2011 and 2010	(1)	1	(1)
Comprehensive income	146	122	88
Less: comprehensive loss attributable to the noncontrolling interests	—	(4)	(6)
Comprehensive income attributable to Portland General Electric Company	$ 146	$ 126	$ 94

See accompanying notes to consolidated financial statements.

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

	As of December 31, 2011	As of December 31, 2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 6	$ 4
Accounts receivable, net	144	137
Unbilled revenues	101	93
Inventories, at average cost:		
Materials and supplies	37	34
Fuel	34	22
Margin deposits	80	83
Regulatory assets—current	216	221
Other current assets	98	67
Total current assets	716	661
Electric utility plant:		
Production	2,854	2,745
Transmission	393	372
Distribution	2,704	2,582
General	314	294
Intangible	331	286
Construction work in progress	120	125
Total electric utility plant	6,716	6,404
Accumulated depreciation and amortization	(2,431)	(2,271)
Electric utility plant, net	4,285	4,133
Regulatory assets—noncurrent	594	544
Nuclear decommissioning trust	37	34
Non-qualified benefit plan trust	36	44
Other noncurrent assets	65	75
Total assets	$ 5,733	$ 5,491

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, 2011	As of December 31, 2010
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 111	$ 102
Liabilities from price risk management activities—current	216	188
Short-term debt	30	19
Current portion of long-term debt	100	10
Regulatory liabilities—current	6	25
Accrued expenses and other current liabilities	151	145
Total current liabilities	614	489
Long-term debt, net of current portion	1,635	1,798
Regulatory liabilities—noncurrent	720	657
Deferred income taxes	529	445
Liabilities from price risk management activities—noncurrent	172	188
Unfunded status of pension and postretirement plans	195	140
Non-qualified benefit plan liabilities	101	97
Other noncurrent liabilities	101	78
Total liabilities	4,067	3,892
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; 75,362,956 and 75,316,419 shares issued and outstanding as of December 31, 2011 and 2010, respectively	836	831
Accumulated other comprehensive loss	(6)	(5)
Retained earnings	833	766
Total Portland General Electric Company shareholders' equity	1,663	1,592
Noncontrolling interests' equity	3	7
Total equity	1,666	1,599
Total liabilities and equity	$ 5,733	$ 5,491

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, 2008	62,575,257	$ 659	$ (5)	$ 700	$ —
Issuance of common stock, net of issuance costs of $6	12,477,500	170	—	—	—
Vesting of restricted and performance stock units	128,175	—	—	—	—
Issuance of shares pursuant to employee stock purchase plan	29,648	—	—	—	—
Noncontrolling interests' capital contribution	—	—	—	—	7
Dividends declared	—	—	—	(76)	—
Net income (loss)	—	—	—	95	(6)
Other comprehensive loss	—	—	(1)	—	—
Balance as of December 31, 2009	75,210,580	829	(6)	719	1
Vesting of restricted and performance stock units	77,281	—	—	—	—
Issuance of shares pursuant to employee stock purchase plan	28,558	1	—	—	—
Noncontrolling interests' capital contributions	—	—	—	—	10
Stock-based compensation	—	1	—	—	—
Dividends declared	—	—	—	(78)	—
Net income (loss)	—	—	—	125	(4)
Other comprehensive income	—	—	1	—	—
Balance as of December 31, 2010	75,316,419	831	(5)	766	7
Vesting of restricted stock units	17,944	—	—	—	—
Issuance of shares pursuant to employee stock purchase plan	25,435	1	—	—	—
Issuance of shares pursuant to dividend reinvestment and direct stock purchase plan	3,158	—	—	—	—
Noncontrolling interests' capital distributions	—	—	—	—	(4)
Stock-based compensation	—	4	—	—	—
Dividends declared	—	—	—	(80)	—
Net income	—	—	—	147	—
Other comprehensive loss	—	—	(1)	—	—
Balance as of December 31, 2011	75,362,956	$ 836	$ (6)	$ 833	$ 3

See accompanying notes to consolidated financial statements.

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

	Years Ended December 31,		
	2011	**2010**	**2009**
Cash flows from operating activities:			
Net income	$ 147	$ 121	$ 89
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	227	238	211
Deferred income taxes	56	67	82
Renewable adjustment clause deferrals	22	(12)	(11)
Regulatory deferral of settled derivative instruments	12	26	(31)
Power cost deferrals, net of amortization	10	(1)	(18)
Increase (decrease) in net liabilities from price risk management activities	9	118	(145)
Regulatory deferrals—price risk management activities	(6)	(118)	145
Senate Bill 408 amortization	(7)	(13)	—
Allowance for equity funds used during construction	(5)	(13)	(18)
Decoupling mechanism deferrals, net of amortization	3	(10)	7
Unrealized gains on non-qualified benefit plan trust assets	—	(5)	(8)
Other non-cash income and expenses, net	38	27	43
Changes in working capital:			
(Increase) decrease in receivables and unbilled revenues	(15)	24	11
Decrease (increase) in margin deposits	3	(27)	133
Income tax refund received	9	53	—
Increase in income taxes receivable	—	(22)	(53)
Increase (decrease) in payables and accrued liabilities	5	(11)	(16)
Other working capital items, net	(7)	—	2
Contribution to pension plan	(26)	(30)	—
Contribution to voluntary employees' benefit association trust	(16)	(1)	—
Distribution of Trojan refund liability	—	—	(34)
Other, net	(6)	(20)	(3)
Net cash provided by operating activities	453	391	386
Cash flows from investing activities:			
Capital expenditures	(300)	(450)	(696)
Purchases of nuclear decommissioning trust securities	(50)	(46)	(36)
Sales of nuclear decommissioning trust securities	46	50	36
Distribution from nuclear decommissioning trust	—	19	—
Other, net	5	(3)	(4)
Net cash used in investing activities	(299)	(430)	(700)

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,		
	2011	**2010**	**2009**
Cash flows from financing activities:			
Proceeds from issuance of long-term debt	$ —	$ 249	$ 580
Payments on long-term debt	(73)	(186)	(142)
Proceeds from issuance of common stock, net of issuance costs	—	—	170
Issuances (maturities) of commercial paper, net	11	19	(65)
Borrowings on short-term debt	—	11	—
Payments on short-term debt	—	(11)	(7)
Borrowings on revolving lines of credit	—	—	82
Payments on revolving lines of credit	—	—	(213)
Dividends paid	(79)	(78)	(72)
Premium paid on repayment of long-term debt	(7)	—	—
Debt issuance costs	—	(2)	(5)
Noncontrolling interests' capital (distributions) contributions	(4)	10	7
Net cash (used in) provided by financing activities	(152)	12	335
Change in cash and cash equivalents	2	(27)	21
Cash and cash equivalents, beginning of year	4	31	10
Cash and cash equivalents, end of year	$ 6	$ 4	$ 31
Supplemental disclosures of cash flow information:			
Cash paid for interest, net of amounts capitalized	$ 103	$ 98	$ 74
Cash paid for income taxes	3	—	2
Non-cash investing and financing activities:			
Accrued capital additions	19	12	17
Accrued dividends payable	21	20	20
Preliminary engineering transferred to Construction work in progress from Other noncurrent assets	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, 2011, PGE served 822,466 retail customers with a service area population of approximately 1.7 million, comprising approximately 44% of the state's population.

As of December 31, 2011, PGE had 2,634 employees, with 840 employees covered under two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 804 and 36 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.

Reclassifications

To conform with the 2011 presentation, PGE reclassified $67 million of accrued expenses in the 2010 consolidated balance sheet, consisting of accrued employee compensation and benefits and other, from Accounts payable to Accrued expenses and other current liabilities, and segregated Renewable adjustment clause deferrals from Other non-cash income and expenses, net in the operating activities section in the 2010 and 2009 consolidated statements of cash flows.

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 none as of December 31, 2011 and 2010.

Accounts Receivable

Accounts receivable are recorded at invoiced amounts and do not bear interest when recorded. Late payment fees on balances in arrears are first assessed 16 business days after the due date. An inactive account balance is charged-off in the period in which the receivable is deemed uncollectible, but no sooner than 45 business days after the final due date.

Estimated provisions for uncollectible accounts receivable related to retail sales, charged to Administrative and other expense, 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 of customer accounts, aging of accounts receivable, bad debt write-offs, actual customer billings, and other factors.

Provisions related to wholesale accounts receivable and unsettled positions, charged to Purchased power and fuel expense, are based on a periodic review and evaluation that includes counterparty non-performance risk and contractual rights of offset when applicable. Actual amounts written off are charged to the allowance for uncollectible accounts.

Price Risk Management

PGE engages in price risk management activities, utilizing financial instruments such as forward, 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, unless they qualify for the normal purchases and normal sales exception. 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 meet the requirements for treatment under the normal purchases and normal sales exception. Other activities consist of certain electricity forwards, options and swaps, certain natural gas forwards, options, and swaps, and forward contracts for acquiring Canadian dollars. Such 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. Contracts that qualify for the normal purchases and normal sales exception are not required to be recorded at fair value. Unrealized gains and losses from contracts that qualify as cash flow hedges are recorded net in Other comprehensive income and contracts not designated as cash flow hedges are recorded net in Purchased power and fuel expense on the statements of income.

Physical electricity sale and purchase transactions are recorded in Revenues and Purchased power and fuel expense upon settlement, respectively, while 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 accompanying consolidated balance sheets and were $80 million and $83 million as of December 31, 2011 and 2010, respectively. Letters of credit provided as collateral are not recorded on the Company's consolidated balance sheet and were $104 million and $180 million as of December 31, 2011 and 2010, 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. Costs include 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 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.

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 8% in 2011 and 2010, and 7% in 2009. AFDC from borrowed funds was $3 million in 2011, $9 million in 2010, and $12 million in 2009 and is reflected as a reduction to Interest expense. AFDC from equity funds was $5 million in 2011, $13 million in 2010, and $18 million in 2009 and is reflected as a component of Other income, net.

Costs which are disallowed for recovery in customer prices 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 2011, 3.9% in 2010, and 3.8% in 2009. Estimated asset retirement removal costs included in depreciation expense were $49 million in the year ended December 31, 2011 and $47 million in each of the years ended December 31, 2010 and 2009.

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 every five years and are filed with the OPUC for approval and inclusion in a future rate proceeding. On September 13, 2010, PGE received an order from the OPUC authorizing new depreciation rates to be effective January 2011.

Thermal production 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):

Production, excluding thermal:	
Hydro	86
Wind	27
Transmission	53
Distribution	40
General	14

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 charged to AROs for assets that meet the definition of a legal obligation and to accumulated asset retirement removal costs, included in Regulatory liabilities, for assets without AROs.

On June 21, 2011, PGE received an order from the OPUC authorizing an increase in customer prices effective July 1, 2011 for depreciation expense and decommissioning costs related to the Company's commitment to cease coal-fired operations at Boardman at the end of 2020.

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 $153 million and $133 million as of December 31, 2011 and 2010, respectively, with amortization expense of $19 million in 2011, $17 million in 2010, and $16 million in 2009. Future estimated amortization expense as of December 31, 2011 is as follows: $20 million in 2012; $14 million in 2013; $12 million in 2014; $11 million in 2015; and $8 million in 2016.

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. 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 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." If the difference between actual NVPC and baseline NVPC falls within the established deadband range, PGE absorbs the incremental cost or benefit, with the difference falling outside the lower and upper thresholds of the deadband range being shared 90/10 between customers and the Company, respectively. Any customer refund or collection is also subject to a regulated earnings test. A refund will occur only to the extent that it results in PGE's actual regulated return on equity (ROE) for that year being no less than 1% above the Company's latest authorized ROE. 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 last authorized ROE. PGE's authorized ROE was 10% for 2011, 2010, and 2009. A final determination of any customer refund or collection is made by the OPUC through an annual public filing and review.

PGE estimates and records amounts related to the PCAM on a quarterly basis during the year. If the projected difference between baseline and actual NVPC for the year exceeds the established deadband, and if forecasted earnings exceed the level required by the regulated earnings test, a regulatory liability is recorded for any future amount payable to retail customers, with offsetting amounts recorded to Purchased power and fuel expense. If the difference is below the lower end of the deadband, a regulatory asset is recorded for any future amount due from retail customers.

For 2011, the deadband ranged from $15 million below to $30 million above baseline NVPC. PGE's actual NVPC as determined pursuant to the PCAM for 2011 was below baseline NVPC by $34 million, which is $19 million below the lower deadband threshold. For 2011, PGE recorded an estimated refund to customers of $10 million, 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 will be made by the OPUC through a public filing and review in 2012.

For 2010, the deadband ranged from $17 million below to $35 million above baseline NVPC. Although PGE's actual NVPC as determined pursuant to the PCAM for 2010 was below baseline NVPC by $12 million, it was within the established deadband range and, accordingly, no customer refund was recorded in 2010. A final determination regarding the 2010 PCAM results was made by the OPUC through a public filing and review in 2011, which concluded that no customer refund was warranted for 2010.

For 2009, the deadband ranged from $15 million below to $29 million above baseline NVPC. Although PGE's actual NVPC as determined pursuant to the PCAM for 2009 exceeded baseline NVPC by $22 million, it was within the established deadband range and, accordingly, no customer collection was recorded in 2009. A final determination regarding the 2009 PCAM results was made by the OPUC through a public filing and review in 2010, which concluded that no customer collection was warranted for 2009.

Asset Retirement Obligations

An ARO is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. PGE recognizes those legal obligations related to dismantlement and restoration costs associated with the future retirement of tangible long-lived assets. 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 removal expenditures is capitalized as an ARO on the consolidated balance sheets and 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.

Contingencies

Contingencies are evaluated using the best information available at the time the consolidated financial statements are prepared. Loss contingencies are accrued and disclosed 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 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) is comprised of the difference between the non-qualified benefit plans' obligations recognized in net income and the unfunded position as of December 31, 2011 and 2010.

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 2011, $39 million in 2010, and $38 million in 2009.

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 accrues 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 service 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 $87 million and $95 million as of December 31, 2011 and 2010, respectively, and will be included in prices when the temporary differences reverse.

Investment tax credits utilized were deferred and amortized to income over the lives of the related properties, and were fully amortized by the end of 2011.

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 Pronouncements

Accounting Standards Update (ASU) 2010-06, *Fair Value Measurements and Disclosures (Topic 820) - Improving Disclosures about Fair Value Measurements* (ASU 2010-06) requires, among other matters, separate reporting about purchases, sales, issuances, and settlements for Level 3 fair value measurements. For additional information on Level 3, see Note 4, Fair Value of Financial Instruments. In accordance with the provisions of ASU 2010-06, PGE adopted this requirement of ASU 2010-06 on January 1, 2011, which did not have a material impact on the Company's consolidated financial position, consolidated results of operations, or consolidated cash flows. All other requirements of ASU 2010-06 were adopted on January 1, 2010 in accordance with ASU 2010-06.

In May 2011, ASU 2011-04, *Fair Value Measurements and Disclosures (Topic 820) - Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs* (ASU 2011-04) was issued. Many of the amendments in ASU 2011-04 change the wording used to describe principles and requirements to align with International Financial Reporting Standards as issued by the International Accounting Standards Board, and are not intended to change the application of Topic 820. Some of the amendments clarify the Financial Accounting Standards Board's intent on the application of existing fair value guidance or change a particular principle or requirement for measuring fair value or fair value disclosures. The amendments in ASU 2011-04 are to be applied prospectively and are effective for interim and annual periods beginning after December 15, 2011 for public entities, with early application not permitted. PGE will adopt the amendments contained in ASU 2011-04 on January 1, 2012, which are not expected to have a material impact on the Company's consolidated financial position, consolidated results of operations, or consolidated cash flows.

In June 2011, ASU 2011-05, *Comprehensive Income (Topic 220) - Presentation of Comprehensive Income* (ASU 2011-05) was issued. The amendments of ASU 2011-05 require, among other things, that an entity report items of other comprehensive income in one of two ways: (i) a single statement with components of net income and total net income, the components of other comprehensive income and total other comprehensive income, and a total for comprehensive income; or (ii) two statements with components of net income and total net income in the first statement, immediately followed by a statement that presents the components of other comprehensive income, a total for other comprehensive income, and a total for comprehensive income. The amendments in ASU 2011-05 are to be applied retrospectively and are effective for interim and annual periods beginning after December 15, 2011, with early application permitted. PGE adopted the amendments contained in ASU 2011-05 on December 31, 2011, which had no impact on the Company's consolidated financial position, consolidated results of operations, or consolidated cash flows.

In December 2011, ASU 2011-12, *Comprehensive Income (Topic 220) - Presentation of Comprehensive Income* (ASU 2011-12) was issued and defers only the changes in ASU 2011-05 that relate to the presentation of reclassification adjustments, which pertain to how and where reclassification adjustments are presented. ASU 2011-12 is effective at the same time as ASU 2011-05. Accordingly, PGE adopted the amendments contained in ASU 2011-12 on December 31, 2011, which had no impact on the Company's consolidated financial position, consolidated results of operations, or consolidated cash flows.

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, 2011 and 2010, respectively. The following is the activity in the allowance for uncollectible accounts (in millions):

	Years Ended December 31,		
	2011	2010	2009
Balance as of beginning of year	$ 5	$ 5	$ 4
Increase in provision	11	7	9
Amounts written off, less recoveries	(10)	(7)	(8)
Balance as of end of year	$ 6	$ 5	$ 5

Trust Accounts

PGE maintains two trust accounts as follows:

Nuclear decommissioning trust—Reflects assets held in trust to cover general decommissioning costs and operation of the Independent Spent Fuel Storage Installation (ISFSI) and represent amounts collected from customers less qualified expenditures plus any realized and unrealized gains and losses on the investments held therein.

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	
	2011	2010	2011	2010
Cash equivalents	$ 14	$ 13	$ —	$ —
Marketable securities, at fair value:				
Equity securities	—	—	10	19
Debt securities	23	21	3	2
Insurance contracts, at cash surrender value	—	—	23	23
	$ 37	$ 34	$ 36	$ 44

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, 2011	As of December 31, 2010
Other current assets:		
Current deferred income tax asset	$ 33	$ —
Assets from price risk management activities	19	13
Income taxes receivable	12	22
Other	34	32
	$ 98	$ 67
Accrued expenses and other current liabilities:		
Accrued employee compensation and benefits	$ 44	$ 36
Accrued interest payable	24	26
Dividends payable	21	20
Other	62	63
	$ 151	$ 145

Other Noncurrent Assets

The Company incurs preliminary engineering costs related to potential future capital projects, which are capitalized in Other noncurrent assets in the consolidated balance sheets. Preliminary engineering costs consist of expenditures for preliminary surveys, plans, and investigations made for the purpose of determining the feasibility of utility projects being considered. Once the project is approved for construction, such costs are reclassified to Electric utility plant. If the project is abandoned, such costs are expensed to Production and distribution expense in the period such determination is made. If any preliminary engineering 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. As of December 31, 2011 and 2010, PGE has recorded preliminary engineering costs of $10 million and $13 million, respectively. For the years ended December 31, 2011, 2010, and 2009, no material preliminary engineering costs were expensed.

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, 2011 and 2010, and then classified 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 any transfers between levels in the fair value hierarchy as of the end of the reporting period. 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, except those net transfers out of Level 3 to Level 2 presented in this note, for the years ended December 31, 2011 and 2010.

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, 2011			
	Level 1	**Level 2**	**Level 3**	**Total**
Assets:				
Nuclear decommissioning trust (1):				
Money market funds	$ —	$ 14	$ —	$ 14
Debt securities:				
Domestic government	3	9	—	12
Corporate credit	—	11	—	11
Non-qualified benefit plan trust (2):				
Equity securities:				
Domestic	7	2	—	9
International	1	—	—	1
Debt securities - domestic government	3	—	—	3
Assets from price risk management activities (1) (3):				
Electricity	—	2	—	2
Natural gas	—	17	—	17
	$ 14	$ 55	$ —	$ 69
Liabilities - Liabilities from price risk management activities (1) (3):				
Electricity	$ —	$ 108	$ 29	$ 137
Natural gas	—	201	50	251
	$ —	$ 309	$ 79	$ 388

(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.

	As of December 31, 2010			
	Level 1	Level 2	Level 3	Total
Assets:				
Nuclear decommissioning trust (1):				
Money market funds	$ —	$ 13	$ —	$ 13
Debt securities:				
Domestic government	3	9	—	12
Corporate credit	—	9	—	9
Non-qualified benefit plan trust (2):				
Equity securities:				
Domestic	16	—	—	16
International	2	1	—	3
Debt securities - domestic government	2	—	—	2
Assets from price risk management activities (1) (3):				
Electricity	—	4	1	5
Natural gas	—	11	—	11
	$ 23	$ 47	$ 1	$ 71
Liabilities - Liabilities from price risk management activities (1) (3):				
Electricity	$ —	$ 102	$ 17	$ 119
Natural gas	—	153	104	257
	$ —	$ 255	$ 121	$ 376

(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 allocated to 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 held in the Nuclear decommissioning trust 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 securities are classified as Level 1 in the fair value hierarchy due to the highly observable nature of the pricing in an active market.

Fair values for municipal debt and corporate credit securities are classified as Level 2 as 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 as pricing inputs are based on unadjusted prices in an active market. Principal markets for equity prices include published exchanges such as NASDAQ and the New York Stock Exchange (NYSE), both American stock exchanges. 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 may not be directly 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 exchange rate risk, mitigate the effects of market fluctuations, and manage 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 quoted forward prices for commodities and interest rates. Substantially all of these assumptions 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 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 over-the-counter forward and swap derivatives. Commodity option contracts whose fair value is derived using standardized valuation techniques, such as Black-Scholes, are also classified as Level 3. Inputs into the valuation of commodity option contracts include forward commodity pricing, forward interest rates, and historic volatilities and correlations.

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 for the year ended December 31, 2011 (in millions):

Net liabilities from price risk management activities as of December 31, 2010	$	120
Net realized and unrealized losses [1]		86
Purchases		3
Settlements		(1)
Net transfers out of Level 3 to Level 2		(129)
Net liabilities from price risk management activities as of December 31, 2011	$	79
Level 3 net unrealized losses that have been fully offset by the effect of regulatory accounting	$	88

(1) Contains nominal amounts of realized losses, net.

The comparable information contained in the preceding table was as follows for the years ended December 31 (in millions):

	2010	2009
Net liabilities from price risk management activities as of beginning of year	$ 154	$ 123
Net realized and unrealized losses [1]	65	47
Purchases, issuances, and settlements, net	27	—
Net transfers out of Level 3 to Level 2	(126)	(16)
Net liabilities from price risk management activities as of end of year	$ 120	$ 154
Level 3 net unrealized losses that have been fully offset by the effect of regulatory accounting	$ 95	$ 49

(1) Contains nominal amounts of realized losses, net.

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. Transfers out of Level 3 occur when the significant inputs become more observable, such as 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.

Long-term debt is recorded at amortized cost in PGE's consolidated balance sheets. The fair value of long-term debt 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, 2011, the estimated aggregate fair value of PGE's long-term debt was $2,091 million, compared to its $1,735 million carrying amount. As of December 31, 2010, the estimated aggregate fair value of PGE's long-term debt was $1,968 million, compared to its $1,808 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, 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 realized. This accounting treatment defers the fair value gains and losses on derivative activities 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 has elected to report gross on the balance sheet the positive and negative exposures resulting from derivative instruments entered into with counterparties where a master netting arrangement exists. As of December 31, 2011 and 2010, the Company had $26 million and $31 million, respectively, in collateral posted with these counterparties, consisting entirely of letters of credit.

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 2015, were as follows (in millions):

	As of December 31,					
	2011			2010		
Commodity contracts:						
Electricity		13	MWh		9	MWh
Natural gas		79	Decatherms		93	Decatherms
Foreign currency exchange	$	6	Canadian	$	7	Canadian

The fair values of PGE's Assets and Liabilities from price risk management activities consist of the following (in millions):

	As of December 31,	
	2011	2010
Current assets:		
Commodity contracts:		
Electricity	$ 2	$ 4
Natural gas	17	9
Total current derivative assets	19 (1)	13 (1)
Noncurrent assets:		
Commodity contracts:		
Electricity	—	1
Natural gas	—	2
Total noncurrent derivative assets	—	3 (2)
Total derivative assets not designated as hedging instruments	$ 19	$ 16
Total derivative assets	$ 19	$ 16
Current liabilities:		
Commodity contracts:		
Electricity	$ 66	$ 77
Natural gas	150	111
Total current derivative liabilities	216	188
Noncurrent liabilities:		
Commodity contracts:		
Electricity	71	42
Natural gas	101	146
Total noncurrent derivative liabilities	172	188
Total derivative liabilities not designated as hedging instruments	$ 388	$ 376
Total derivative liabilities	$ 388	$ 376

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

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,		
	2011	2010	2009
Commodity contracts:			
Electricity	$ 117	$ 127	$ 79
Natural Gas	98	192	101

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, 2011, 2010, and 2009, $192 million, $258 million, and $98 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, 2011 related to PGE's derivative activities would be realized as a result of the settlement of the underlying derivative instrument (in millions):

	2012	2013	2014	2015	Total
Commodity contracts:					
Electricity	$ 64	$ 42	$ 21	$ 8	$ 135
Natural gas	132	72	24	6	234
Net unrealized loss	$ 196	$ 114	$ 45	$ 14	$ 369

The Company's secured and unsecured debt is currently rated at investment grade by Moody's Investors Service (Moody's) and Standard and 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, 2011 was $321 million, for which the Company had $104 million in posted collateral, consisting entirely of letters of credit. If the credit-risk-related contingent features underlying these agreements were triggered at December 31, 2011, the cash requirement to either post as collateral or settle the instruments immediately would have been $302 million.

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

	As of December 31,	
	2011	2010
Assets from price risk management activities:		
Counterparty A	19%	1%
Counterparty B	16	1
Counterparty C	13	5
Counterparty D	7	22
Counterparty E	7	23
Counterparty F	—	11
Counterparty G	—	10
	62%	73%
Liabilities from price risk management activities:		
Counterparty E	23%	24%
Counterparty H	10	4
Counterparty I	7	12
	40%	40%

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, 2011 Current	As of December 31, 2011 Noncurrent	As of December 31, 2010 Current	As of December 31, 2010 Noncurrent
Regulatory assets:					
Price risk management [(2)]	2 years	$ 194	$ 172	$ 175	$ 185
Pension and other postretirement plans [(2)]	(3)	—	295	—	213
Deferred income taxes [(2)]	(4)	—	87	—	95
Deferred broker settlements [(2)]	1 year	11	—	24	—
Renewable energy deferral	1 year	1	—	22	—
Debt reacquisition costs [(2)]	7 years	—	28	—	23
Other [(5)]	Various	10	12	—	28
Total regulatory assets		$ 216	$ 594	$ 221	$ 544
Regulatory liabilities:					
Asset retirement removal costs [(6)]	(4)	$ —	$ 637	$ —	$ 588
Asset retirement obligations [(6)]	(4)	—	36	—	33
Power cost adjustment mechanism	(7)	—	10	—	—
Trojan ISFSI pollution control tax credits	(7)	—	7	18	4
Other	Various	6	30	7	32
Total regulatory liabilities		$ 6	$ 720	$ 25	$ 657

(1) As of December 31, 2011.
(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 $21 million and $26 million as of December 31, 2011 and 2010, respectively.
(6) Included in rate base for ratemaking purposes.
(7) Refund period not yet determined.

As of December 31, 2011, PGE had regulatory assets of $22 million earning a return on investment at the following rates: (i) $7 million at PGE's authorized cost of capital, currently 8.033%; (ii) $7 million at the approved rate for deferred accounts under amortization, ranging from 2.01% to 4.27%, depending on the year of approval; and (iii) $8 million earning a return by inclusion in rate base.

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. During the fourth quarter of 2011, PGE received an order from the OPUC on its Annual Update Tariff for 2012 net variable power costs (NVPC). Pursuant to the order, the OPUC reduced the Company's 2012 NVPC forecast by approximately $3 million, which is reflected as a reduction to the regulatory asset for price risk management as of

December 31, 2011. 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.

Renewable energy deferral reflects the net revenue requirement related to new renewable resources and associated transmission that are not yet included in customer prices, with the majority related to Biglow Canyon Wind Farm. Recovery of net revenue requirements associated with new renewable resources, which are required by the 2007 Oregon Renewable Energy Act, is allowed under a renewable adjustment clause mechanism authorized 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.

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, which are included in Other noncurrent liabilities in the consolidated balance sheets, consist of the following (in millions):

	As of December 31,	
	2011	2010
Trojan decommissioning activities	$ 37	$ 38
Utility plant	38	16
Non-utility property	12	10
Asset retirement obligations	$ 87	$ 64

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 Independent Spent Fuel Storage Installation (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 permanent off-site storage is available. Decommissioning of the ISFSI and final site restoration activities will begin once shipment of all the spent fuel to a U.S. 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 are seeking approximately $128 million in damages. PGE's share of any recovery would be approximately 67%. A trial before the U.S. Court of Federal Claims commenced in the fourth quarter of 2011, with a decision expected during 2012. However, if the Plaintiffs were to prevail, the USDOE would likely appeal, which would defer any damage payment indefinitely. The Trojan ARO will not be impacted by the outcome of this case as such potential recovery is for past decommissioning costs and the ARO reflects only future decommissioning expenditures. Any proceeds received related to this legal matter would be returned to customers to offset amounts previously collected in relation to Trojan decommissioning activities.

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, as well as the Bull Run hydro project. Decommissioning work has been substantially completed at Bull Run, with only environmental monitoring continuing through 2012.

During 2011, an updated decommissioning study for PGE's Boardman coal-fired plant 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.

Non-utility property primarily represents ARO's 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,		
	2011	2010	2009
Balance as of beginning of year	$ 64	$ 63	$ 58
Liabilities incurred	1	1	—
Liabilities settled	(4)	(3)	(4)
Accretion expense	4	4	4
Revisions in estimated cash flows	22	(1)	5
Balance as of end of year	$ 87	$ 64	$ 63

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: REVOLVING CREDIT FACILITIES

PGE has two unsecured revolving credit facilities, with an aggregate borrowing capacity of $670 million, as follows:

- A $370 million syndicated credit facility, of which $10 million is scheduled to terminate in July 2012 and $360 million in July 2013;
- A $300 million syndicated credit facility, which is scheduled to terminate in December 2016.

Pursuant to the terms of the agreements, both 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 credit facilities 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, 2011, PGE was in compliance with this covenant with a 51.5% debt ratio.

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

Pursuant to an order issued by the FERC, the Company is authorized to issue short-term debt up to $700 million through February 6, 2014. The authorization provides that if utility assets financed by unsecured debt are divested, then a proportionate share of the unsecured debt must also be divested.

As of December 31, 2011, PGE had no borrowings and $30 million in commercial paper outstanding under the credit facilities, with $124 million in letters of credit issued. As of December 31, 2011, the aggregate unused available credit under the credit facilities is $516 million.

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

	Years Ended December 31,		
	2011	2010	2009
Average daily amount of short-term debt outstanding	$ 2	$ 9	$ 28
Weighted daily average interest rate *	0.4%	0.4%	1.3%
Maximum amount outstanding during the year	$ 44	$ 51	$ 205

* 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,	
	2011	2010
First Mortgage Bonds, rates range from 3.46% to 9.31%, with a weighted average rate of 5.83% in 2011 and 5.85% in 2010, due at various dates through 2040	$ 1,615	$ 1,678
Pollution Control Revenue Bonds:		
Port of Morrow, Oregon, 5% rate, due 2033	23	23
City of Forsyth, Montana, 5% rate, due 2033	119	119
Port of St. Helens, Oregon, 5.25% rate, due in 2014	—	10
Total Pollution Control Revenue Bonds	142	152
Pollution Control Revenue Bonds owned by PGE	(21)	(21)
Unamortized debt discount	(1)	(1)
Total long-term debt	1,735	1,808
Less: current portion of long-term debt	(100)	(10)
Long-term debt, net of current portion	$ 1,635	$ 1,798

First Mortgage Bonds—The Indenture securing PGE's First Mortgage Bonds constitutes a direct first mortgage lien on substantially all regulated utility property, other than expressly excepted property. On December 29, 2011, PGE redeemed $63 million of the 6.5% series due 2014.

Pollution Control Revenue Bonds—PGE has the option to remarket Pollution Control Revenue Bonds held by the Company through 2033. 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 and could be backed by first mortgage bonds or a bank letter of credit depending on market conditions.

As of December 31, 2011, the future minimum principal payments on long-term debt are as follows (in millions):

Years ending December 31:	
2012	$ 100
2013	100
2014	—
2015	70
2016	67
Thereafter	1,398
	$ 1,735

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. Such closure did not change the benefits provided to existing participants under the plan.

The assets of the pension plan are held in a trust and are comprised of equity, debt, and alternative asset investment vehicles, 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.

During 2011 and 2010, PGE made contributions to the pension plan of $26 million and $30 million, respectively, with no contributions in 2009. No contributions to the pension plan are expected in 2012.

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, 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 (SERP), 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. The Company also provides two retired employees with death benefits through a split dollar life insurance policy which pays a fixed amount to the beneficiary and for which the Company has a security interest for the amount of premiums paid. 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):

	2011			2010		
	NQBP	Other NQBP	Total	NQBP	Other NQBP	Total
Non-qualified benefit plan trust	$ 17	$ 19	$ 36	$ 19	$ 25	$ 44
Non-qualified benefit plan liabilities *	25	76	101	24	73	97

* For the NQBP, excludes the current portion of $2 million in 2011 and 2010, 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,			
	2011		2010	
	Actual	Target *	Actual	Target *
Defined Benefit Pension Plan:				
Equity securities	68%	67%	68%	67%
Debt securities	32	33	32	33
Total	100%	100%	100%	100%
Other Postretirement Benefit Plans:				
Equity securities	61%	72%	46%	47%
Debt securities	39	28	54	53
Total	100%	100%	100%	100%
Non-Qualified Benefits Plans:				
Equity securities	30%	23%	42%	42%
Debt securities	7	14	5	7
Insurance contracts	63	63	53	51
Total	100%	100%	100%	100%

* The Target for the Defined Benefit 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):

	As of December 31, 2011			
	Level 1	Level 2	Level 3	Total
Defined Benefit Pension Plan assets:				
Money market funds	$ —	$ 3	$ —	$ 3
Equity securities:				
Domestic	151	12	—	163
International	54	51	—	105
Debt securities:				
Domestic government and corporate credit	—	78	—	78
Corporate credit	76	—	—	76
Private equity funds	—	—	32	32
Alternative investments	—	—	30	30
	$ 281	$ 144	$ 62	$ 487
Other Postretirement Benefit Plans assets:				
Money market funds	$ —	$ 7	$ —	$ 7
Equity securities:				
Domestic	12	1	—	13
International	2	2	—	4
Debt securities—Domestic government	3	—	—	3
	$ 17	$ 10	$ —	$ 27

	As of December 31, 2010			
	Level 1	Level 2	Level 3	Total
Defined Benefit Pension Plan assets:				
Money market funds	$ —	$ 15	$ —	$ 15
Equity securities:				
Domestic	52	111	—	163
International	53	53	—	106
Debt securities—Domestic government and corporate credit	68	70	—	138
Private equity funds	—	—	23	23
Alternative investments	—	—	28	28
	$ 173	$ 249	$ 51	$ 473
Other Postretirement Benefit Plans assets:				
Money market funds	$ —	$ 7	$ —	$ 7
Equity securities:				
Domestic	3	2	—	5
International	1	1	—	2
Debt securities—Domestic government	2	—	—	2
	$ 6	$ 10	$ —	$ 16

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—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.

Alternative investments—Investments in a portable alpha strategy are comprised of long positions in S&P 500 futures contracts and a hedge fund-of-funds comprised of diversified group, by sector and market capitalization of long only, short only and/or both long/short equity hedge funds. Valuation of hedge funds included within this vehicle is provided by fund managers using unobservable internally modeled inputs. PGE performs validation procedures of manager performance by comparing stated performance against published benchmarks. Alternative investments are classified as level 3 due to lack of observable market inputs and relative illiquidity of the fund.

Changes in the fair value of assets held by the pension plan classified as Level 3 in the fair value hierarchy presented in the table above were as follows for the years ended December 31, 2011 and 2010 (in millions):

	Private equity	Alternative assets	Total Level 3
Balance as of December 31, 2009	$ 17	$ 23	$ 40
Purchases and sales, net	4	2	6
Realized gain on sales	1	—	1
Unrealized gain on assets	1	3	4
Balance as of December 31, 2010	23	28	51
Purchases	7	—	7
Realized loss on sales	(2)	—	(2)
Unrealized gain on assets	4	2	6
Balance as of December 31, 2011	$ 32	$ 30	$ 62

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, 2011 and 2010. Obligations related to the Other NQBP are not included in the following tables (dollars in millions):

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2011	2010	2011	2010	2011	2010
Benefit obligation:						
As of January 1	$ 550	$ 491	$ 79	$ 77	$ 25	$ 27
Service cost	12	11	2	2	—	—
Interest cost	29	28	4	4	1	1
Participants' contributions	—	—	2	2	—	—
Actuarial loss (gain)	69	42	(5)	1	3	—
Benefit payments	(26)	(22)	(7)	(7)	(2)	(3)
As of December 31	$ 634	$ 550	$ 75	$ 79	$ 27	$ 25
Fair value of plan assets:						
As of January 1	$ 473	$ 406	$ 16	$ 19	$ 19	$ 20
Actual return on plan assets	14	59	—	1	—	2
Company contributions	26	30	16	1	—	—
Participants' contributions	—	—	2	2	—	—
Benefit payments	(26)	(22)	(7)	(7)	(2)	(3)
As of December 31	$ 487	$ 473	$ 27	$ 16	$ 17	$ 19
Unfunded position as of December 31	$ (147)	$ (77)	$ (48)	$ (63)	$ (10)	$ (6)
Accumulated benefit plan obligation as of December 31	$ 566	$ 503	N/A	N/A	$ 27	$ 25
Classification in consolidated balance sheet:						
Noncurrent asset	$ —	$ —	$ —	$ —	$ 17	$ 19
Current liability	—	—	—	—	(2)	(2)
Noncurrent liability	(147)	(77)	(48)	(63)	(25)	(23)
Net liability	$ (147)	$ (77)	$ (48)	$ (63)	$ (10)	$ (6)

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2011	2010	2011	2010	2011	2010
Amounts included in comprehensive income:						
Net actuarial loss (gain)	$ 97	$ 22	$ (4)	$ 1	$ 2	$ —
Amortization of net actuarial loss	(8)	(3)	(1)	(1)	(1)	(1)
Amortization of prior service cost	(1)	(1)	(1)	(1)	—	—
	$ 88	$ 18	$ (6)	$ (1)	$ 1	$ (1)
Amounts included in AOCL*:						
Net actuarial loss	$ 275	$ 186	$ 15	$ 20	$ 10	$ 9
Prior service cost	1	2	4	5	—	—
	$ 276	$ 188	$ 19	$ 25	$ 10	$ 9
Assumptions used:						
Discount rate used to calculate benefit obligation	5.00%	5.47%	3.76% - 4.90%	4.02% - 5.40%	5.00%	5.47%
Weighted average rate of increase in future compensation levels	3.71%	3.80%	4.58%	4.83%	N/A	N/A
Long-term rate of return on plan assets	8.25%	8.50%	7.09%	6.44%	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		
	2011	2010	2009	2011	2010	2009	2011	2010	2009
Service cost	$ 12	$ 11	$ 11	$ 2	$ 2	$ 2	$ —	$ —	$ —
Interest cost on benefit obligation	29	28	31	4	4	4	1	1	2
Expected return on plan assets	(42)	(39)	(43)	(1)	(1)	(1)	—	—	—
Amortization of prior service cost	1	1	1	1	1	1	—	—	—
Amortization of net actuarial loss	8	3	—	1	1	1	1	1	—
Net periodic benefit cost	$ 8	$ 4	$ —	$ 7	$ 7	$ 7	$ 2	$ 2	$ 2

PGE estimates that $20 million will be amortized from AOCL into net periodic benefit cost in 2012, 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					
	2012	2013	2014	2015	2016	2017 - 2021
Defined benefit pension plan	$ 31	$ 32	$ 34	$ 36	$ 37	$ 209
Other postretirement benefits	4	4	4	4	5	23
Non-qualified benefit plans	2	2	2	3	2	11
Total	$ 37	$ 38	$ 40	$ 43	$ 44	$ 243

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 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;
- For 2010, 8% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2011 through 2013, and assumed to decrease 0.5% per year thereafter, reaching 5% in 2019; and
- For 2009, 7.5% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2010, and assumed to decrease 0.5% per year thereafter, reaching 5% in 2015.

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, and would increase or decrease the postretirement benefit obligation by less than $1 million.

401(k) Retirement Savings Plan

PGE sponsors a 401(k) Plan that covers substantially all employees. For eligible employees hired prior to February 1, 2009, the Company matches employee contributions up to 6% of the participating employee's base pay. For eligible employees hired after January 31, 2009, and/or who are not otherwise covered by a defined benefit pension plan, PGE matches up to 5% of the participating employee's base salary and, whether or not an employee contributes to the 401 (k) Plan, the Company contributes 5% of the employee's base salary.

For bargaining employees, who are subject to the International Brotherhood of Electrical Workers Local 125 agreements, the Company contributes a stated amount per compensable hour plus 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 of approximately $16 million, $15 million, and $14 million during the years ended December 31, 2011, 2010, and 2009.

NOTE 11: INCOME TAXES

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

	Years Ended December 31,		
	2011	2010	2009
Current:			
Federal	$ 2	$ (20)	$ (46)
State and local	—	—	—
	2	(20)	(46)
Deferred:			
Federal	43	61	78
State and local	13	12	6
	56	73	84
Investment tax credit adjustments	—	—	(2)
Income tax expense	$ 58	$ 53	$ 36

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,		
	2011	2010	2009
Federal statutory tax rate	35.0%	35.0%	35.0%
Federal tax credits	(12.7)	(10.4)	(8.3)
State and local taxes, net of federal tax benefit	2.6	4.4	3.4
Flow through depreciation and cost basis differences	2.1	0.1	(1.6)
Investment tax credit amortization	—	—	(1.5)
Other	1.3	1.2	1.8
Effective tax rate	28.3%	30.3%	28.8%

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

	As of December 31,	
	2011	2010
Deferred income tax assets:		
Price risk management	$ 145	$ 72
Employee benefits	135	98
Tax credits, net of valuation allowance	56	40
Regulatory liabilities	22	37
Tax loss carryforwards	1	17
Total deferred income tax assets	359	264
Deferred income tax liabilities:		
Depreciation and amortization	572	534
Regulatory assets	274	175
Other	9	4
Total deferred income tax liabilities	855	713
Deferred income tax liability, net	$ (496)	$ (449)
Classification of net deferred income taxes:		
Current deferred income tax asset (1)	$ 33	$ —
Current deferred income tax liability (2)	—	(4)
Noncurrent deferred income tax liability	(529)	(445)
	$ (496)	$ (449)

(1) Included in Other current assets in the consolidated balance sheets.
(2) Included in Accrued expenses and other current liabilities in the consolidated balance sheets.

Certain reclassifications have been made to the 2010 deferred income tax assets and deferred income tax liabilities presented in the preceding table to conform with the 2011 presentation and include the following: (i) an increase in Depreciation and amortization and a decrease in Regulatory liabilities of $220 million related to asset retirement obligations; (ii) an increase in Price risk management and a decrease in Regulatory liabilities of $74 million related to fair value adjustments; (iii) an increase in Employee benefits and a decrease in Regulatory assets of $73 million related to actuarial adjustments; and (iv) an increase in Regulatory assets and a decrease in Other of $8 million related to reacquired long-term debt.

As of December 31, 2011, PGE had no federal loss carryforwards and state loss carryforwards of less than $1 million, which will expire at various dates from 2016 through 2031. In addition, PGE has federal and state tax credit carryforwards of $42 million and $14 million, respectively, which will expire at various dates from 2012 through 2031.

PGE believes that it is more likely than not that its deferred income tax assets as of December 31, 2011 will be realized; accordingly, no valuation allowance has been recorded. As of December 31, 2010, PGE believed the benefit from state credit carryforwards expiring in 2011 would not be realized and, in recognition of this risk, the Company recorded a valuation allowance of $2 million on the deferred tax assets relating to these state credit carryforwards. During 2011, these state credit carryforwards expired unused. The net change in the valuation allowance for the years ended December 31, 2011 and 2010 were decreases of $2 million and $1 million, respectively.

As of December 31, 2010, the amount of the Company's unrecognized tax benefit was $2 million, including interest, resulting from a gross increase in a position taken in a prior period. During the year ended December 31, 2010, the Company recognized $1 million in interest and no penalties. During the first quarter of 2011, the unrecognized tax benefit of $2 million was recognized as a result of filing for a federal tax accounting method change. As of December 31, 2011, PGE has no unrecognized tax benefits.

PGE files income tax returns in the U.S. federal jurisdiction, the states of Oregon and Montana, and certain local jurisdictions. The Internal Revenue Service (IRS) performed an examination of PGE's income tax returns for 2007 and 2008 during 2010. This audit closed in the first quarter of 2011, with no material findings. In addition, the IRS commenced examination of the 2006, 2009, and 2010 income tax returns in the fourth quarter of 2011. The Company is not currently under examination by state or local tax authorities.

NOTE 12: STOCK PURCHASE PLANS

Employee Stock Purchase Plan

PGE has an employee stock purchase plan (ESPP), under which a total of 625,000 shares of the Company's common stock may be issued. The ESPP permits all eligible employees to purchase shares of PGE common stock through regular payroll deductions, which are limited to 10% of base pay. Each year, employees may purchase up to a maximum of $25,000 in common stock (based on fair value on the purchase date) or 1,500 shares, whichever is less. 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, 2011, there were 507,594 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, 2011, there were 2,496,842 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 (Restricted Stock Units) and performance-based vesting conditions (Performance Stock Units) 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 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 3,931,204 shares remain available for future issuance as of December 31, 2011.

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 Stock Units vest if performance goals are met at the end of a three-year performance period; such goals include return on equity and regulated asset base growth measures. Vesting of Performance 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 and Performance 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 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 and Performance Stock Unit activity is summarized in the following table:

	Units	Weighted Average Grant Date Fair Value
Outstanding as of December 31, 2008	360,382	25.04
Granted	243,574	14.95
Forfeited	(4,847)	24.85
Vested	(176,846)	23.60
Outstanding as of December 31, 2009	422,263	19.82
Granted	191,469	19.18
Forfeited	(45,081)	23.45
Vested	(103,223)	25.78
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

The number of vested Restricted and Performance Stock Units presented above exceed the number of shares issued for the vesting of restricted and performance stock units on the consolidated statements of equity because, upon vesting, the Company withholds a portion of the vested shares for the payment of income taxes on behalf of the employees. The total value of Restricted and Performance Stock Units vested during the years ended December 31, 2011, 2010, and 2009 was $1 million, $3 million and $4 million, respectively. The weighted average fair value is measured based on the closing price of PGE common stock on the date of grant. For the years ended December 31, 2011, 2010, and 2009, PGE recorded $4 million, $2 million and $1 million, respectively, of stock-based compensation expense, 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 less than $1 million in 2011, 2010, and 2009, which is not included in Administrative and other expenses in the consolidated statements of income.

As of December 31, 2011, unrecognized stock-based compensation expense was $4 million, of which approximately $3 million and $1 million is expected to be expensed in 2012 and 2013, respectively. Stock-based compensation expense was calculated assuming the attainment of performance goals that would allow the vesting of 121.8%, 117.9%, and 91.1% of awarded Performance Stock Units for 2011, 2010, and 2009, respectively, with an estimated 6% forfeiture rate. No stock-based compensation costs have been capitalized and the plan had no material impact on cash flows for the years ended December 31, 2011, 2010, or 2009.

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. Dilutive potential common shares consist of Restricted Stock Units and employee stock purchase plan shares. Unvested Performance Stock Units and related DERs are not included in the computation of dilutive securities because vesting of these instruments is dependent upon the attainment of required criteria over three-year performance periods. For additional information on Performance Stock Units and DERs, see Note 13, Stock-Based Compensation Expense.

Components of basic and diluted earnings per share are as follows:

	Years Ended December 31,		
	2011	**2010**	**2009**
Numerator (in millions):			
Net income attributable to Portland General Electric Company common shareholders	$ 147	$ 125	$ 95
Denominator (in thousands):			
Weighted average common shares outstanding—basic	75,333	75,275	72,790
Dilutive effect of unvested restricted stock units and employee stock purchase plan shares	17	16	62
Weighted average common shares outstanding—diluted	75,350	75,291	72,852
Earnings per share—basic and diluted	**$ 1.95**	**$ 1.66**	**$ 1.31**

Basic and diluted earnings per share amounts are calculated based on actual amounts rather than the rounded amounts presented in the table above and on the consolidated statements of income. Accordingly, calculations using the rounded amounts presented for net income and weighted average shares outstanding may yield results that vary from the earnings per share amounts presented in the table above.

NOTE 15: COMMITMENTS AND GUARANTEES

Commitments

As of December 31, 2011, PGE's future minimum payments pursuant to purchase obligations for the following five years and thereafter are as follows (in millions):

	Payments Due						
	2012	2013	2014	2015	2016	Thereafter	Total
Capital and other purchase commitments	$ 58	$ 18	$ 10	$ 10	$ 6	$ 73	$ 175
Purchased power and fuel:							
Electricity purchases	129	77	76	76	57	381	796
Capacity contracts	21	21	21	20	19	—	102
Public Utility Districts	7	8	8	8	7	30	68
Natural gas	49	22	22	20	12	11	136
Coal and transportation	25	19	9	—	—	—	53
Operating leases	9	10	9	10	10	196	244
Total	$ 298	$ 175	$ 155	$ 144	$ 111	$ 691	$ 1,574

Capital and other purchase commitments—Certain commitments have been made for capital and other purchases for 2012 and beyond. Such commitments include those related to hydro licenses, upgrades to production, distribution and transmission facilities, decommissioning activities, information systems, and system maintenance work. 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 2036, and power capacity contracts through 2016. As of December 31, 2011, PGE has power sale contracts with counterparties of approximately $13 million in 2012.

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, 2011	PGE Share		Contract Expiration	PGE Cost, including Debt Service		
		Output	Capacity		2011	2010	2009
			(in MW)				
Priest Rapids and Wanapum	$ 917	8.8%	176	2052	$ 14	$ 10	$ 17
Wells	259	19.4	159	2018	10	7	8
Portland Hydro	11	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 and Beaver generating plants.

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 2014.

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 above 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 PGE's Beaver and Port Westward generating plants operate, which expires in 2096. Rent expense was $9 million in 2011 and in 2010, and $7 million in 2009.

The future minimum operating lease payments presented is net of sublease income of: $3 million in 2012; $2 million in 2013, 2014, and 2015; and $1 million in 2016. Sublease income was $3 million in 2011, 2010, and 2009.

Guarantees

PGE entered into a sale transaction in 1985 in which it sold an undivided 15% interest in Boardman and a 10.714% undivided interest in the Pacific Northwest Intertie (Intertie) transmission line (jointly the Boardman Assets) to an unrelated third party (Purchaser). The Purchaser leased the Boardman Assets to a lessee (Lessee) unrelated to PGE or the Purchaser. Concurrently, PGE assigned to the Lessee certain agreements for the sale of power and transmission services from Boardman and the Intertie (P&T Agreements) to a regulated electric utility (Utility) unrelated to PGE, the Purchaser, or the Lessee. The P&T Agreements expire on December 31, 2013. The payments by the Utility under the P&T Agreements exceed the payments to be made by the Lessee to the Purchaser under the lease. In exchange for PGE undertaking certain obligations of the Lessee under the lease, the Lessee reassigned to PGE certain rights, including the excess payments, under the P&T Agreements. However, in the event that the Utility defaults on the payments it owes under the P&T Agreements, PGE may be required to pay the damages owed by the Lessee to the Purchaser under the lease. Assuming no recovery from the Utility and no reduction in damages from mitigating sales or leases related to the Boardman Assets and P&T Agreements, the maximum amount that would be owed by PGE in 2012 is approximately $74 million. Management believes that circumstances that could result in such amount, or any lesser amount, being owed by the Company are remote.

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, 2011, 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, 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 the expected losses of the LLCs.

During 2010 and 2009, impairment losses of $4 million and $5 million, respectively, were recognized on the photovoltaic solar power facilities held by the LLCs and classified in Depreciation and amortization expense in PGE's consolidated statements of income. Based on PGE's intent to ultimately acquire 100% of the LLCs and the fact that the capitalized cost of the photovoltaic solar power facilities exceeded the undiscounted cash flows of the respective facility over its estimated useful life, impairment analyses were performed. The impairment losses were equal to the excess of the carrying amounts over the estimated fair values of the photovoltaic solar power facilities. Estimated fair values were determined using the discounted cash flow method, assuming a discount rate (after taxes) of approximately 7%, which is PGE's allowed rate of return, and estimated useful lives ranging from 20 to 25 years. The new cost basis of the photovoltaic solar power facilities are amortized over their remaining estimated useful lives. The valuation technique used to measure fair value of the photovoltaic solar power facilities at the impairment date is considered Level 3 in the fair value hierarchy, as described in Note 4, Fair Value of Financial Instruments.

As noted above, PGE has consolidated the VIEs even though it has less than a 1% ownership interest in the LLCs. The participating members are allocated their proportionate share of the LLCs net losses based on the respective members' ownership percent. Accordingly, the majority of the impairment losses are attributable to the noncontrolling interests through the Net losses attributable to noncontrolling interests in PGE's consolidated statements of income for the years ended December 31, 2010 and 2009.

Included in PGE's consolidated balance sheets are LLC net assets as follows (in millions):

	As of December 31,	
	2011	**2010**
Cash and cash equivalents	$ 1	$ 1
Accounts receivable	—	4
Electric utility plant, net	5	5

These assets can only be used to settle the obligations of the consolidated VIEs.

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.

As of December 31, 2011, 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	65.00%	1980	$ 467	$ 292	$ 2
Colstrip	20.00	1986	507	326	2
Pelton/Round Butte .	66.67	1958 / 1964	206	46	11
Total			$ 1,180	$ 664	$ 15

* Excludes asset retirement obligations 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.

Loss contingencies are accrued and disclosed 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 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 return on, its Trojan costs in a general rate case filing with the OPUC. The OPUC issued a general rate order that granted the Company recovery of, and a 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 PGE 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 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 that required PGE to refund $15.4 million, plus interest at 9.6% from September 30, 2000, to customers who received service from PGE during the period 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 have separately appealed the 2008 Order to the Oregon Court of Appeals. Oral arguments were made on February 3, 2012 and a decision by the Oregon Court of Appeals remains pending.

Class Actions. In a separate legal proceeding, two 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 of $260 million, plus interest, as a result of PGE's inclusion, in prices charged to customers, of a return on its investment of 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 it can offer to PGE customers, through price reductions or refunds, for any amount of return on the Trojan investment PGE collected in prices for the period from April 1, 1995 through October 1, 2000.

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.

Because the above matters involve unsettled legal theories and have a broad range of potential outcomes, management cannot estimate a range of potential loss. Management believes, however, that these matters will not have a material impact on the financial condition of the Company, but may have a material impact on the results of operations and cash flows in future reporting periods.

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 its decision, concluding that the FERC failed to adequately explain how it considered or examined new evidence showing intentional market manipulation in California and its 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. 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. 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, contesting, among other things, the applicable refund period reflected in the Order, the use of the *Mobile-Sierra* standard, any restraints in the Order on the type of evidence that could be introduced in the hearing, and the lack of market-wide remedy. The rehearing requests remain pending.

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. The settlement proceedings are ongoing.

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.

Management cannot predict whether the FERC will order refunds in the Pacific Northwest Refund proceeding, which contracts would be subject to refunds, or how such refunds, if any, would be calculated. Accordingly, management cannot estimate a range of potential loss. Management believes, however, that the outcome will not have a material impact on the financial condition of the Company, but may have a material impact on PGE's results of operations and cash flows in future reporting periods.

EPA Investigation of Portland Harbor

A 1997 investigation by the EPA of a segment of the Willamette River known as the 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 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.

The Portland Harbor site is currently undergoing a remedial investigation and feasibility study (RI/FS) pursuant to an Administrative Order on Consent (AOC) between the EPA and several PRPs, not including PGE. In the AOC, the EPA determined that the RI/FS would focus on a segment of the river approximately 5.7 miles in length.

In January 2008, the EPA requested information from various parties, including PGE, concerning properties in or near the 5.7 mile segment of the river being examined in the RI/FS, as well as several miles beyond. Subsequently, the EPA has listed additional PRPs, which now number over one hundred.

The EPA will determine the boundaries of the site at the conclusion of the RI/FS in a Record of Decision in which it will document its findings and select a preferred cleanup alternative. The EPA is not expected to issue the Record of Decision until 2014.

Sufficient information is currently not available to determine the total cost of any required investigation or remediation of the Portland Harbor site or the liability of PRPs, including PGE. Accordingly, management cannot estimate a range of potential loss. Management believes, however, that the outcome will not have a material impact on the financial condition of the Company, but may have a material impact on PGE's results of operations and cash flows in future reporting periods.

EPA Investigation of Harbor Oil

Harbor Oil, Inc. operated an oil reprocessing business on a site located in north Portland (Harbor Oil), until about 1999. Subsequently, other companies have continued to conduct operations on the site. Until 2003, PGE contracted with the operators of the site to provide used oil from the Company's power plants and electrical distribution system to the operators for use in their reprocessing business. Other entities continue to utilize Harbor Oil for the reprocessing of used oil and other lubricants.

In 1974 and 1979, major oil spills occurred at the Harbor Oil site. Elevated levels of contaminants, including metals, pesticides, and polychlorinated biphenyls, have been detected at the site. In 2003, the EPA included the Harbor Oil site on the National Priority List as a federal Superfund site.

PGE received a Notice from the EPA in 2005, in which the Company was named as one of fourteen PRPs with respect to Harbor Oil. In 2007, an AOC was signed by the EPA and six other parties, including PGE, to implement an RI/FS at Harbor Oil. In 2011, the final draft of the remedial investigation report was submitted to the EPA, which has yet to issue a response.

Sufficient information is currently not available to determine the total cost of investigation and remediation of Harbor Oil or the liability of the PRPs, including PGE. Accordingly, management cannot estimate a range of potential loss. Management believes, however, that the outcome of this matter will not have a material impact on the financial condition of the Company, but may have a material impact on PGE's results of operations and cash flows in future reporting periods.

Revenue Bonds

In 2008, PGE repurchased $5.8 million of Pollution Control Revenue Bonds Series 1996 (Bonds) issued through the Port of Morrow. In connection with the repurchase, PGE paid the $5.8 million repurchase price to Lehman Brothers Inc. (Lehman) as remarketing agent for the Bonds, who in turn paid off the beneficial owner of the Bonds. As a result of the payment, PGE became the beneficial owner of the Bonds and requested that Lehman safe-keep the Bonds in Lehman's Depository Trust Company participant account until such time as the Bonds could be remarketed. After repurchase of the Bonds, PGE removed the liability for the Bonds from its financial statements.

In September 2008, Lehman filed for protection under Chapter 11 of the U.S. Bankruptcy Code. PGE subsequently filed a claim for return of the Bonds from Lehman. In November 2009, the trustee appointed to liquidate the assets of Lehman (Trustee) allowed PGE's claim as a net equity claim for securities. At the time, PGE believed it would receive back the entire amount of the Bonds at some point during the bankruptcy proceedings.

It is not certain that the Company will receive the full amount of the Bonds but could, along with other claimants, potentially receive a pro-rata share of certain assets. The timing and extent of distributions on claims are subject to the ultimate disposition of numerous claims in the proceedings and certain major contingencies which the Trustee must resolve. PGE cannot currently estimate how much of the value of the Bonds will ultimately be returned to the Company or the timing of the distribution from Lehman. Management does not expect the outcome of this matter to have a material impact on the Company's financial condition, but it may have a material impact on PGE's results of operations and cash flows in a future interim reporting period.

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 its business, which may result in adverse judgments against the Company. Although management currently believes that resolution of such matters will not have a material effect 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)			
2011				
Revenues, net	$ 484	$ 411	$ 439	$ 479
Income from operations	115	57	68	69
Net income	69	22	27	29
Net income attributable to Portland General Electric Company	69	22	27	29
Earnings per share—basic and diluted (1)	0.92	0.29	0.36	0.38
2010				
Revenues, net (2)	$ 449	$ 415	$ 464	$ 455
Income from operations (2)	61	57	90	59
Net income (2)	27	24	48	22
Net income attributable to Portland General Electric Company (2)	27	24	49	25
Earnings per share—basic and diluted (1) (2)	0.36	0.32	0.65	0.34

(1) 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.
(2) Revenues for the fourth quarter of 2010 include the reversal of an estimated collection from customers that had been recorded as of September 30, 2010 in the amount of $24 million related to the regulatory treatment of income taxes (SB 408) for 2010.

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 such term is 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 in recording, processing, summarizing and reporting, on a timely basis, the information relating to the Company (including its consolidated subsidiaries) required to be disclosed by the Company in the reports that it files or submits under the Exchange Act and are effective in ensuring that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is accumulated and communicated to the Company's management, including the Company's Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

(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 such term is 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.

The Company's internal control over financial reporting includes policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and disposition of the assets; provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures are being made only in accordance with authorizations of management and the directors of the Company; and 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 Company's financial statements.

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 issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management has concluded that, as of December 31, 2011, the Company's internal control over financial reporting is effective.

The Company’s internal control over financial reporting, as of December 31, 2011, 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, 2011.

(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 2011 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—The Board 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 23, 2012.

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 23, 2012.

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 23, 2012.

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 23, 2012.

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 23, 2012.

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).
4.2*	Fortieth Supplemental Indenture dated October 1, 1990 (Form 10-K for the year ended December 31, 1990, Exhibit 4) (File No. 1-05532-99).
4.3*	Fifty-sixth Supplemental Indenture dated May 1, 2006 (Form 8-K filed May 25, 2006, Exhibit 4.1).
4.4*	Fifty-seventh Supplemental Indenture dated December 1, 2006 (Form 8-K filed December 22, 2006, Exhibit 4.1).
4.5*	Fifty-eighth Supplemental Indenture dated April 1, 2007 (Form 8-K filed April 12, 2007, Exhibit 4.1).
4.6*	Fifty-ninth Supplemental Indenture dated October 1, 2007 (Form 8-K filed October 5, 2007, Exhibit 4.1).
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).
(10)	**Material Contracts**
10.1*	Separation Agreement between Enron Corp. and Portland General Electric Company dated April 3, 2006 (Form 8-K filed April 3, 2006, Exhibit 10.1).
10.2*	Five Year Credit Agreement dated May 27, 2005, between Portland General Electric Company, JP Morgan Chase Bank, N.A., as Administrative Agent, and a group of lenders (Form 8-K filed June 2, 2005, Exhibit 4.1).
10.3	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.

Exhibit Number	Description
	Exhibits 10.4 through 10.15 were filed in connection with the Company's 1985 Boardman/Intertie Sale:
10.4*	Long-term Power Sale Agreement dated November 5, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.5*	Long-term Transmission Service Agreement dated November 5, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 001-05532-99).
10.6*	Participation Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.7*	Lease Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.8*	PGE-Lessee Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.9*	Asset Sales Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.10*	Bargain and Sale Deed, Bill of Sale, and Grant of Easements and Licenses dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.11*	Supplemental Bill of Sale dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.12*	Trust Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.13*	Tax Indemnification Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.14*	Trust Indenture, Mortgage and Security Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.15*	Restated and Amended Trust Indenture, Mortgage and Security Agreement dated February 27, 1986 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.16*	Portland General Electric Company Severance Pay Plan for Executive Employees dated June 15, 2005 (Form 8-K filed June 20, 2005, Exhibit 10.1). +
10.17*	Portland General Electric Company Outplacement Assistance Plan dated June 15, 2005 (Form 8-K filed June 20, 2005, Exhibit 10.2). +
10.18*	Portland General Electric Company 2005 Management Deferred Compensation Plan dated January 1, 2005 (Form 10-K filed March 11, 2005, Exhibit 10.18). +
10.19*	Portland General Electric Company Management Deferred Compensation Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.1). +
10.20*	Portland General Electric Company Supplemental Executive Retirement Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.2). +
10.21*	Portland General Electric Company Senior Officers' Life Insurance Benefit Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.3). +
10.22*	Portland General Electric Company Umbrella Trust for Management dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.4). +
10.23*	Portland General Electric Company 2006 Stock Incentive Plan, as amended (Form 10-K filed February 27, 2008, Exhibit 10.23). +

Exhibit Number	Description
10.24*	Portland General Electric Company 2006 Annual Cash Incentive Master Plan (Form 8-K filed March 17, 2006, Exhibit 10.1). +
10.25*	Portland General Electric Company 2006 Outside Directors' Deferred Compensation Plan (Form 8-K filed May 17, 2006, Exhibit 10.1). +
10.26*	Portland General Electric Company 2008 Annual Cash Incentive Master Plan for Executive Officers (Form 8-K filed February 26, 2008, Exhibit 10.1). +
10.27*	Form of Portland General Electric Company Agreement Concerning Indemnification and Related Matters (Form 8-K filed December 24, 2009, Exhibit 10.1). +
10.28*	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). +
10.29*	Form of Directors' Restricted Stock Unit Agreement (Form 8-K filed July 14, 2006, Exhibit 10.1). +
10.30*	Form of Officers' and Key Employees' Performance Stock Unit Agreement (Form 8-K filed March 13, 2008, Exhibit 10.1). +
10.31*	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.
(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.

** In accordance with Regulation S-T, the XBRL-related information in Exhibit 101 to this Annual Report on Form 10-K shall be deemed "furnished" and not "filed."

Certain instruments defining the rights of holders of other long-term debt of the Company 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. The Company 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 SW Salmon Street, Portland, Oregon 97204, PGE 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 23, 2012.

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 23, 2012.

Signature	Title
/s/ JAMES J. PIRO **James J. Piro**	*President, Chief Executive Officer, and Director (principal executive officer)*
/s/ MARIA M. POPE **Maria M. Pope**	*Senior Vice President, 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/ DAVID A. DIETZLER **David A. Dietzler**	*Director*
/s/ KIRBY A. DYESS **Kirby A. Dyess**	*Director*
/s/ PEGGY Y. FOWLER **Peggy Y. Fowler**	*Director*
/s/ MARK B. GANZ **Mark B. Ganz**	*Director*
/s/ CORBIN A. MCNEILL, JR. **Corbin A. McNeill, Jr.**	*Director*
/s/ NEIL J. NELSON **Neil J. Nelson**	*Director*
/s/ M. LEE PELTON **M. Lee Pelton**	*Director*
/s/ ROBERT T. F. REID **Robert T. F. Reid**	*Director*

EXHIBIT 12.1

PORTLAND GENERAL ELECTRIC COMPANY
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(Dollars in thousands)

	Years Ended December 31,				
	2,011	2,010	2,009	2,008	2,007
Income from continuing operations before income taxes	$ 204,714	$ 178,158	$ 131,636	$ 121,825	$ 220,123
Total fixed charges	126,766	131,486	129,948	111,589	98,682
Total earnings	$ 331,480	$ 309,644	$ 261,584	$ 233,414	$ 318,805
Fixed charges:					
Interest expense	$ 110,413	$ 110,240	$ 103,389	$ 90,257	$ 74,362
Capitalized interest	3,059	9,097	11,816	6,184	9,596
Interest on certain long-term power contracts	8,764	8,068	10,038	10,010	9,552
Estimated interest factor in rental expense	4,530	4,081	4,705	5,138	5,172
Total fixed charges	$ 126,766	$ 131,486	$ 129,948	$ 111,589	$ 98,682
Ratio of earnings to fixed charges	2.61	2.35	2.01	2.09	3.23

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-170686 on Form S-3 and Registration Statement Nos. 333-135726, 333-142694, and 333-158059 on Form S-8 of our report dated February 23, 2012, relating to the consolidated financial statements of Portland General Electric Company, and the effectiveness of Portland General Electric Company's internal control over financial reporting, appearing in this Annual Report on Form 10-K of Portland General Electric Company for the year ended December 31, 2011.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 23, 2012

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 23, 2012

/s/ JAMES J. PIRO

James J. Piro

President and

Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, Maria M. Pope, 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 23, 2012

/s/ MARIA M. POPE

Maria M. Pope
Senior Vice President, 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 Maria M. Pope, Senior Vice President, 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, 2011, as filed with the Securities and Exchange Commission on February 24, 2012 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	/s/ MARIA M. POPE
James J. Piro	**Maria M. Pope**
President and Chief Executive Officer	*Senior Vice President, Finance, Chief Financial Officer, and Treasurer*
Date: February 23, 2012	Date: February 23, 2012

2011 Accomplishments

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

$147 million

Net income for the year

93 percent

PGE's plant availability

1.75 megawatts

Amount of renewable energy that can be generated from the new Baldock solar high-way project built by PGE and the Oregon Department of Transportation

Coyote Springs

Turbine upgrade completed on time, on budget — and with better-than-expected results

Cascade Crossing

The Obama administration named this proposed transmission project one of seven pilot projects for streamlined federal permitting and increased cooperation at the federal, state and tribal levels

99.999 percent

Service reliability for PGE customers

1

Rank for green pricing programs *and* for renewable-energy sales to residential customers

High customer satisfaction

Top decile for business and industrial customers and top quartile for residential customer satisfaction ratings (Market Strategies International survey)

SB 967

Legislation directing the Oregon Public Utility Commission to address taxes during rate cases passed, replacing SB 408, Oregon's complex utility-tax law

$1.6 million

Amount contributed to the community through PGE's employee giving campaign

Corporate Information

Board of Directors

Corbin A. McNeill, Jr.
Chairman of the Board of Directors
Portland General Electric;
Retired Chairman and Co-CEO
Exelon Corporation

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

Peggy Y. Fowler
Retired Chief Executive Officer and President
Portland General Electric

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

Robert T. F. Reid
Retired Chair and Corporate Director
British Columbia Transmission Corporation

Corporate Officers

James J. Piro
President and Chief Executive Officer

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

Maria M. Pope
Senior Vice President, Finance, Chief Financial Officer and Treasurer

Arleen N. Barnett
Vice President, Administration

O. Bruce Carpenter
Vice President, Distribution

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

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

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

James F. Lobdell
Vice President, Power Operations and Resource Strategy

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

W. David Robertson
Vice President, Public Policy

Kristin A. Stathis
Vice President, Customer Service Operations

Investor Information

Corporate Headquarters
Portland General Electric Company
121 SW Salmon Street
Portland, OR 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, OR 97204
503.222.1341

Form 10-K
A copy of the company's 2011 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
1WTC0403
Portland, OR 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

Image on cover: *PGE Lineman Ryan Hagel; Biglow Canyon Wind Farm*

Images on back, from left: *West Side Hydro Equipment Operator Mike Nehez and Engineer Cheryl Norris at River Mill; River Mill Hydro Plant; PGE crews restoring power to residents along the Sandy River; Coyote Springs; Technician Ron Benage at Coyote Springs*





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