PORTLAND GENERAL ELECTRIC CO /OR/
Form 10-K
February 22, 2013

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, 2012

OR

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

For the Transition period from to

Commission File Number 001-05532-99

PORTLAND GENERAL ELECTRIC COMPANY
(Exact name of registrant as specified in its charter)

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

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

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

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

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

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

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

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

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

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

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

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

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

As of June 29, 2012, the aggregate market value of voting common stock held by non-affiliates of the Registrant was $2,008,462,492. For purposes of this calculation, executive officers and directors are considered affiliates.

As of February 15, 2013, there were 75,557,037 shares of common stock outstanding.

Documents Incorporated by Reference

Part III, Items 10 - 14	Portions of Portland General Electric Company's definitive proxy statement to be filed pursuant to Regulation 14A for the Annual Meeting of Shareholders to be held on May 22, 2013.

PORTLAND GENERAL ELECTRIC COMPANY
FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2012

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DEFINITIONS

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

Abbreviation or Acronym	Definition
AFDC	Allowance for funds used during construction
ARO	Asset retirement obligation
AUT	Annual Power Cost Update Tariff
Beaver	Beaver natural gas-fired generating plant
Biglow Canyon	Biglow Canyon Wind Farm
Boardman	Boardman coal-fired generating plant
BPA	Bonneville Power Administration
CAA	Clean Air Act
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
Moody’s	Moody’s Investors Service
MW	Megawatts
MWa	Average megawatts
MWh	Megawatt hours
NRC	Nuclear Regulatory Commission
NVPC	Net Variable Power Costs
OATT	Open Access Transmission Tariff
OPUC	Public Utility Commission of Oregon
PCAM	Power Cost Adjustment Mechanism
Port Westward	Port Westward natural gas-fired generating plant
RPS	Renewable Portfolio Standard
S&P	Standard & Poor’s Ratings Services
SEC	United States Securities and Exchange Commission
Trojan	Trojan nuclear power plant
USDOE	United States Department of Energy
VIE	Variable interest entity

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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. The Company operates as a cost-based, regulated electric utility, with revenue requirements and customer prices determined based on the forecasted cost to serve retail customers, and a reasonable rate of return as determined by the Public Utility Commission of Oregon (OPUC). PGE's retail load requirement is met with both Company-owned generation and power purchased in the wholesale market. The Company also participates in the wholesale market by purchasing and selling electricity and natural gas in 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 2012 its service area population was 1.7 million, comprising approximately 44% of the state's population. During 2012, the Company added 5,888 customers and as of December 31, 2012, served a total of 828,354 retail customers.

PGE had 2,603 employees as of December 31, 2012, with 809 employees covered under one of two separate agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 775 and 34 employees and expire in February 2015 and August 2014, respectively.

Available Information

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

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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 and cyber security standards, natural gas pipelines, hydroelectric projects, accounting policies and practices, short-term debt issuances, and certain other matters.

Wholesale Energy—PGE has authority under its FERC Market-Based Rates tariff to charge market-based rates for wholesale energy sales. Re-authorization for continued use of such rates requires the filing of triennial market power studies with the FERC. The Company'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, 2012, 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, 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 the Company's 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. and Generating Facilities section in Item 2.—"Properties."

Accounting Policies and Practices—Pursuant to applicable provisions of the Federal Power Act, PGE prepares financial statements in accordance with the accounting requirements of the FERC, as set forth in its applicable

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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. For additional information on spent nuclear fuel storage activities, see Note 7, Asset Retirement Obligations in the Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data."

State of Oregon Regulation

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

The OPUC reviews and approves the Company's retail prices (see "Ratemaking" below) and establishes conditions of utility service. In addition, the OPUC regulates the issuance of securities, prescribes accounting policies and practices, and reviews applications to sell utility assets and engage in transactions with affiliated companies, as well as applications of persons or entities seeking to 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.

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 Oregon's governor, with staff support provided by the Oregon Department of Energy.

Integrated Resource Plan—Unless the OPUC directs otherwise, PGE is required to file with the OPUC an Integrated Resource Plan (IRP) within two years of its previous IRP acknowledgment order. Based on direction from the OPUC, PGE is required to file its next IRP in November 2013. The IRP guides the utility on how it will meet future customer demand and describes the Company's future energy supply strategy, reflecting new technologies, market conditions, and regulatory requirements. The primary goal of the IRP is to identify an acquisition plan for generation, transmission, demand-side and energy efficiency resources that, along with the Company's existing portfolio, provides the best combination of expected cost and associated risks and uncertainties for PGE and its customers. For additional information on PGE's most recent IRP, see "Future Energy Resource Strategy" in the Power Supply section in this Item 1.

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

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representing PGE customer groups. The following are the more significant regulatory mechanisms and proceedings under which customer prices are determined:

- General Rate Cases. PGE periodically evaluates the need to change its retail electric price structure to sufficiently cover its operating costs and provide a reasonable rate of return. Such changes are requested pursuant to a comprehensive general rate case process that includes 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. In February 2013, PGE filed a general rate case with a 2014 test year (2014 General Rate Case). For additional information, see the Overview section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."
- Power Costs. In addition to price changes resulting from the general rate case process, the OPUC has approved the following mechanisms by which PGE can adjust retail customer prices to cover the Company's Net Variable Power Costs (NVPC), which consist of the cost of purchased power and fuel used in generation (including related transportation costs) less revenues from wholesale power and fuel sales:

Annual Power Cost Update Tariff (AUT). Under this tariff, customer prices are adjusted annually to reflect the latest forecast of NVPC. Such forecasts assume 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 expected operating conditions for thermal generating plants. An initial NVPC forecast, submitted to the OPUC by April 1st each year, is updated during such year and finalized in November of the same year. Based upon the final forecast, new prices, as approved by the OPUC, become effective at the beginning of the next calendar year; and

Power Cost Adjustment Mechanism (PCAM). Customer prices can also be adjusted to reflect a portion of the difference between each year's forecasted NVPC included in prices (baseline NVPC) and actual NVPC for the year. Under the PCAM, PGE is subject to a portion of the business risk or benefit associated with the difference between actual NVPC and baseline NVPC. The PCAM utilizes an asymmetrical deadband range within which PGE absorbs cost variances, with a 90/10 sharing of such variances between customers and the Company outside of the deadband. The deadband range is fixed at $15 million below, to $30 million above, baseline NVPC. Annual results of the PCAM are subject to application of a regulated earnings test, under which a refund will occur only to the extent that it results in PGE's actual regulated return on equity (ROE) for that year being no less than 1% above the Company's latest authorized ROE. A collection will occur only to the extent that it results in PGE's actual regulated ROE for that year being no greater than 1% below the Company's authorized ROE. A final determination of any customer refund or collection is made by the OPUC through a public filing and review typically during the second half of the following year. For additional information, see the Results of Operations section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

- Renewable Energy. The 2007 Oregon Renewable Energy Act (the Act) established a Renewable Portfolio Standard (RPS) which requires that PGE serve at least 5% of its retail load with renewable resources by 2011, 15% by 2015, 20% by 2020, and 25% by 2025. PGE met the 2011 requirement and expects to have sufficient resources to meet the 2015 requirements with additional resources included in its most recent IRP. The Act also allows Renewable Energy Credits, resulting from energy generated from qualified renewable resources placed in service after January 1, 1995 and certified low impact hydroelectric power resources, to be used to meet the Company's RPS compliance obligation. 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 in 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 index based pricing. All commercial and industrial customers are eligible for direct access, whereby customers purchase their electricity from an Electricity Service Supplier (ESS), and 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 index based price. Certain large commercial and industrial customers may elect to be removed from cost-of-service pricing for a fixed three-year or a minimum five-year term, to be served either by an ESS or PGE under a daily market index based price. Participation in the fixed three-year and minimum five-year opt-out programs is capped at 300 average megawatts (MWa).

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

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

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

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

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

Decoupling—The decoupling mechanism, authorized through 2013, is intended to provide for recovery of margin lost as a result of a reduction in electricity sales attributable to energy efficiency and conservation efforts by residential and certain commercial customers. The mechanism provides for collections from customers if weather adjusted use per customer is lower than levels included in the Company's most recent general rate case; it also

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provides for customer refunds if weather adjusted use per customer exceeds levels included in the most recent general rate case.
During 2012, PGE recorded an estimated refund of $1 million, which resulted from weather adjusted use per customer being slightly higher than levels projected 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, 2013. For 2011, the Company recorded an estimated refund of $2 million, as weather adjusted use per customer was slightly higher than levels included in the 2011 General Rate Case. After review, the OPUC approved refunds to customers over a one-year period that began June 1, 2012.

Regulatory Accounting

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

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

Customers and Revenues

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

Retail Revenues

Retail customers are classified as residential, commercial, or industrial, with no single customer representing more than 4% of PGE’s total retail revenues or 5% of total retail deliveries. While the 20 largest commercial and industrial customers constituted 11% of total retail revenues in 2012, they represented nine different groups including high technology, paper manufacturing, metal fabrication, health services, and governmental agencies.

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

	Years Ended December 31,								
	2012			2011			2010		
Retail revenues[1] (dollars in millions):									
Residential	$860	50	%	$877	51	%	$803	48	%
Commercial	633	37		635	37		601	36	
Industrial	226	13		226	13		221	14	
Subtotal	1,719	100		1,738	101		1,625	98	
Other accrued (deferred) revenues, net	4	—		(16)	(1)		39	2	
Total retail revenues	$1,723	100	%	$1,722	100	%	$1,664	100	%
Retail energy deliveries[2] (MWh in thousands):									
Residential	7,505	39	%	7,733	40	%	7,452	40	%
Commercial	7,402	39		7,419	38		7,277	39	
Industrial	4,283	22		4,193	22		4,004	21	
Total retail energy deliveries	19,190	100	%	19,345	100	%	18,733	100	%
Average number of retail customers:									
Residential	723,440	87	%	719,977	87	%	717,719	88	%
Commercial	103,766	13		102,940	13		102,282	12	
Industrial	261	—		255	—		265	—	
Total	827,467	100	%	823,172	100	%	820,266	100	%

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

Additional averages for retail customers are as follows:

	Years Ended December 31,		
	2012	2011	2010
Usage per customer (in kilowatt hours):			
Residential	10,375	10,740	10,384
Commercial	71,343	72,075	71,148
Industrial	16,409,211	16,572,913	15,051,038
Revenue per customer (in dollars):			
Residential	$1,113	$1,160	$1,049
Commercial	6,041	6,194	5,825
Industrial	863,402	900,805	828,536
Revenue per kilowatt hour (in cents):			
Residential	10.72 ¢	10.80 ¢	10.10 ¢
Commercial	8.47	8.59	8.19
Industrial	5.26	5.44	5.50

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

In accordance with state regulations, PGE's retail customer prices are 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 that include a daily market price option, renewable energy options, which are offered to residential and small commercial customers, and time-of-use options. 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.

While the number of residential customers increased during 2012, total residential deliveries decreased 2.9% compared to 2011 driven by warmer weather conditions during the heating season in 2012. During 2011, as a result of cooler weather during the heating season and an increase in the average number of customers, total residential deliveries increased 3.8% compared to 2010.

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

In 2012, the unfavorable weather effects compared with 2011 nearly offset the addition of an average of over 800 new customers, contributing to the 0.2% decrease in deliveries to commercial customers compared with 2011, while Oregon non-farm employment increased 1.2%. In 2011, the favorable weather effects combined with the addition of an average of nearly 700 new customers contributed to the 2.0% increase in deliveries to commercial customers compared with 2010, as Oregon non-farm employment increased 1.6%.

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 driven by economic conditions, with weather having little impact on this customer class.

A change in economic activity can lead to a change in energy demand from the Company's industrial customers. In 2012, the Company's industrial energy deliveries increased 2.1% compared to 2011, driven primarily by expansion in the high tech sector. In 2011, industrial deliveries rose 4.7% compared to 2010 as demand increased from certain paper production customers, and the general economic conditions improved.

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 the RAC, the PCAM, and the decoupling mechanism. For further information on these items, see “State of Oregon Regulation” in the Regulation and Rates section of this Item 1.

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Wholesale Revenues

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

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

Seasonality

Demand for electricity by PGE's residential and, to a lesser extent, commercial 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 number of degree-days, the greater the expected demand for heating or cooling.

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

	Heating Degree-Days	Cooling Degree-Days
2012	4,169	436
2011	4,650	362
2010	4,187	314
15-year average for 2012	4,235	456

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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 tables present the Company’s average winter and summer loads for the periods indicated along with the corresponding peak load and month in which it occurred:

Winter Loads (MW)

	Average	Peak	Month
2012	2,529	3,426	January
2011	2,612	3,555	January
2010	2,445	3,582	November

Summer Loads (MW)

	Average	Peak	Month
2012	2,249	3,597	August
2011	2,233	3,340	September
2010	2,220	3,544	August

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

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Power Supply

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

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

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

	As of December 31,								
	2012			2011			2010		
	Capacity	%		Capacity	%		Capacity	%	
Generation:									
Thermal:									
Natural gas	1,172	28	%	1,172	28	%	1,157	24	%
Coal	670	16		670	16		670	14	
Total thermal	1,842	44		1,842	44		1,827	38	
Hydro (1)	489	12		489	12		489	10	
Wind (2)	450	11		450	11		450	9	
Total generation	2,781	67		2,781	67		2,766	57	
Purchased power:									
Long-term contracts:									
Capacity/exchange	160	4		190	4		540	11	
Hydro	588	14		579	14		743	15	
Wind	39	1		38	1		38	1	
Solar	13	—		6	—		—	—	
Other	117	3		110	3		135	3	
Total long-term contracts	917	22		923	22		1,456	30	
Short-term contracts	475	11		458	11		612	13	
Total purchased power	1,392	33		1,381	33		2,068	43	
Total resource capacity	4,173	100	%	4,162	100	%	4,834	100	%

(1) Capacity represents nameplate and differs from expected energy to be generated, which is expected to range from 195 MWa to 245 MWa, dependent upon river flows.

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

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For information regarding actual generating output and purchases for the years ended December 31, 2012, 2011 and 2010, see the Results of Operations section of Item 7.—“Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

Generation

The portion of PGE’s retail load requirements generated by its plants varies from year to year and is determined by various factors, including planned and forced outages, availability and price of coal and natural gas, precipitation and snow-pack levels, the market price of electricity, and wind variability.

Thermal	PGE has a 65% ownership interest in Boardman, which it operates, and a 20% ownership interest in Colstrip Units 3 and 4 (Colstrip), which is operated by a third party. These two coal-fired generating facilities provided approximately 19% of the Company’s total retail load requirement in 2012, compared with 21% in 2011 and 26% in 2010. The Company’s three natural gas-fired generating facilities, Port Westward, Beaver, and Coyote Springs, provided approximately 15% of its total retail load requirement in 2012, compared with 11% in 2011 and 24% in 2010.

The thermal plants provide reliable power for the Company’s customers and capacity reserves. These resources have a combined capacity of 1,842 MW, representing approximately 66% of the net capacity of PGE’s generating facilities. Thermal plant availability, excluding Colstrip, was 92% in 2012, compared with 90% in 2011 and 94% in 2010, while Colstrip plant availability was 93% in 2012, compared with 84% in 2011 and 95% in 2010.

Hydro	The Company’s FERC-licensed hydroelectric projects consist of Pelton/Round Butte on the Deschutes River near Madras, Oregon (discussed below), four plants on the Clackamas River, and one on the Willamette River. The licenses for these projects expire at various dates ranging from 2035 to 2055. Although these plants have a combined capacity of 489 MW, actual energy received is dependent upon river flows. Energy from these resources provided 10% of the Company’s total retail load requirement in 2012, 2011, and 2010, with availability of 99% in 2012, compared with 100% in 2011 and 99% in 2010. 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 on or after December 31, 2021. The Tribes have a second option to purchase an undivided 0.02% interest in Pelton/Round Butte at its discretion on or after April 1, 2041. If both options are exercised by the Tribes, the Tribes’ ownership percentage would exceed 50%.

Wind	Biglow Canyon Wind Farm (Biglow Canyon), located in Sherman County, Oregon, is PGE’s largest renewable energy resource with 217 wind turbines with a total nameplate capacity of approximately 450 MW. It was completed and placed in service in three phases between December 2007 and August 2010. The energy from Biglow Canyon provided 6% of the Company’s total retail load requirement in both 2012 and 2011, and 4% in 2010. Availability for Biglow Canyon was 98% in 2012, compared with 97% in 2011 and 96% in 2010. The expected energy from wind resources differs from the nameplate capacity and is expected to range from 135 MWa to 180 MWa for Biglow Canyon, dependent upon wind conditions.

Dispatchable Standby Generation (DSG)—PGE has a DSG program under which the Company can start, operate, and monitor customer-owned 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, 2012, there were 40 projects that together can provide approximately 87 MW

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of diesel-fired capacity at peak times. In addition, there were 10 projects under construction that are expected to provide an additional 18 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 2013 for the purchase of coal to fill open positions for 2014 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 "Capital Requirements" in the Liquidity and Capital Resources 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, 2012. The current operating permit for Beaver limits the number of gallons of fuel oil that can be burned daily, which effectively limits the daily hours of operation of Beaver on fuel oil.

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

Purchased Power

PGE supplements its own generation with power purchased in the wholesale market to meet its retail load requirements. The Company utilizes short- and long-term wholesale power purchase contracts in an effort to

provide the most favorable economic mix on a variable cost basis. Such contracts have original terms ranging from one month to 53 years and expire at varying dates through 2055.

PGE's medium term power cost strategy helps mitigate the effect of price volatility on its customers due to changing energy market conditions. The strategy allows the Company to take positions in power and fuel markets up to five years in advance of physical delivery. By purchasing a portion of anticipated energy needs for future years over an extended period, PGE mitigates a portion of the potential future volatility in the average cost of purchased power and fuel.
The Company's major power purchase contracts consist of the following (also see the preceding table which summarizes the average resource capabilities related to these contracts):

Capacity/exchange—PGE has two contracts that provide PGE with firm capacity to help meet the Company's peak loads. The contract representing 10 MW of capacity expires in May 2014 and the contract representing 150 MW of capacity expires in December 2016.

Hydro—The Company has three contracts that provide for the purchase of power generated from hydroelectric projects with an aggregate capacity of 98 MW and which expire between 2015 and 2017. In addition, PGE has the following:

- Mid-Columbia hydro—PGE has long-term power purchase contracts with certain public utility districts in the state of Washington for a portion of the output of three hydroelectric projects on the mid-Columbia River. The contract representing 159 MW of capacity expires in 2018 and the contract representing 181 MW of capacity expires in 2052. Although the projects currently provide a total of 340 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. The Tribes may elect to sell its output to another party with a one year notice to PGE.

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

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

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

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

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

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Future Energy Resource Strategy

PGE's most recent IRP (2009 IRP) was acknowledged by the OPUC in November 2010 and 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. To meet the projected energy requirements, the IRP includes energy efficiency measures, new renewable resources, new transmission capability, new generation plants, and improvements to existing generation 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;
- Approximately 100 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 service territory. For additional information on the Cascade Crossing Transmission Project (Cascade Crossing), see "Capital Requirements and Financing" in the Overview section contained in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations";
- New natural gas generation facilities to help meet additional base load requirements estimated at 300 to 500 MW;
- New natural gas generation facilities to help meet peak capacity requirements estimated at up to 200 MW;
- Seasonal peaking resources, consisting of 200 MW of bi-seasonal (winter and summer) peaking supply and 150 MW of winter-only peaking supply; 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 "Capital Requirements" in the Liquidity and Capital Resources section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

In accordance with PGE's IRP and pursuant to the OPUC's competitive bidding guidelines, the Company issued two RFPs during 2012 for additional resources, with one for capacity and energy resources and another for renewable resources. The RFP for capacity and energy resources is seeking approximately 300 MW to 500 MW of baseload 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 baseload energy resources expected to be available in the 2014 to 2017 timeframe. The RFP for renewable resources is seeking approximately 100 MWa of renewable resources, which would be expected to be available to meet PGE's 2015 requirements under Oregon's renewable energy standard.

PGE has evaluated the capacity and energy resources bids received. PGE's benchmark proposal was selected in the RFP seeking 200 MW of year-round flexible and peaking resources. See Port Westward Unit 2 in the Capital Requirements section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations." The Company is in the process of negotiations with the top bidder from the final short list for baseload energy resources. The bids on the final short list include power purchase agreements and PGE-ownership options. In addition, PGE is in the process of negotiating power purchase agreements for the seasonal peaking resources. Final resource selections are expected by mid-2013. The Company is evaluating renewable resources bids received, and expects a final short list by March 2013, with final resource selection by mid-2013. An independent evaluator selected by the OPUC is helping conduct the RFP and reviewing bids to ensure an objective and impartial process.

In November 2012, the Company filed an informational update to its 2009 IRP, for which PGE is not proposing any changes to its action plan and no action is required by the OPUC. PGE is required to file its next IRP by November 29, 2013.

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 2012, PGE delivered approximately 20 million megawatt hours (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 Bonneville Power Administration (BPA) to transmit a significant amount of the Company's generation to its distribution system. PGE's transmission system, together with contractual rights on other transmission systems, enables the Company to integrate and access generation resources to meet its customers' energy requirements. PGE's generation is managed on a coordinated basis to obtain maximum load-carrying capability and efficiency. The Company's transmission and distribution systems are located as follows:

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

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 current acknowledged IRP includes a proposal for a 500 kV transmission line referred to as the Cascade Crossing Transmission Project, or Cascade Crossing, that would help meet future electricity demand. The project would transmit power from new and existing energy resources in northeastern Oregon to the Company's service territory. For additional information, see "Capital and Financing" in the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

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

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

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Environmental Matters

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

Air Quality

Clean Air Act—PGE's operations, primarily its thermal generating plants, are subject to regulation under the federal Clean Air Act (CAA), which addresses, among other things, particulate matter, hazardous air pollutants, and greenhouse gas emissions (GHGs). Oregon and Montana, the states in which PGE 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 December 2011, the EPA issued new emissions limits under the CAA's National Emission Standards for Hazardous Air Pollutants (NESHAP) to regulate air 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). The Company believes the Boardman plant should meet the MACT requirements without additional capital investment, once installation of the emissions controls already anticipated to meet the revised rules for SO_2 and NO_x emissions at Boardman is complete. Those anticipated controls include a Dry Sorbent Injection system to be added to Boardman in 2014, at an estimated capital cost to the Company of $27 million, including allowance for funds used during construction (AFDC). DEQ rules provide for coal-fired operation at Boardman to cease no later than December 31, 2020.

The operator of the Colstrip plant has provided the Company with estimated costs for emissions control modifications to Units 3 and 4 that may be necessary to meet the MACT requirements at Colstrip. 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.

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

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

Climate Change—No comprehensive GHG emissions legislation has been considered and voted on by Congress since 2009. However, state, regional, and federal legislative efforts continue with respect to establishing regulation of greenhouse gas (GHG) emissions and their potential impacts on climate change. The EPA has taken the lead role on climate change policy utilizing existing authority under the CAA to develop regulations. Areas of focus for the Company include the following:

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In December 2010, the EPA announced a proposed settlement agreement with states and environmental groups that would require the EPA to set GHG New Source Performance Standards (NSPS) for new and modified fossil fuel-based power plants, and guidelines for state-developed NSPS for existing sources. The emissions standard for new gas and coal fired electric generating units was proposed in April 2012 and is

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expected to be finalized in the second quarter of 2013. EPA is also expected to propose guidance for state-developed NSPS for existing sources, including modified sources, in 2013.

- The State of Oregon has established a non-binding policy guideline that sets a goal to reduce GHG emissions to 10% below 1990 levels by 2020. Although the guideline does not mandate reductions by any specific entity nor include penalties for failure to meet the goal, the Company is required to report to the DEQ the amount of GHG emissions produced along with the total amount of energy produced or purchased by PGE for consumption in Oregon.
- During 2012, the Company submitted the first required GHG emissions report applicable to its transmission and distribution system to both the EPA and the DEQ.

Any laws that would impose emissions taxes or mandatory reductions in GHG emissions may have a material impact on PGE’s operations, as the Company utilizes fossil fuels in its own power generation and other companies use such fuels to generate power that PGE purchases in the wholesale market. PGE’s 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 and Montana, the Departments of Environmental Quality are responsible for reviewing proposed projects under this requirement to ensure that federally approved activities will meet water quality standards and policies established by the respective state. PGE has obtained permits where required, and has certificates of compliance for its hydroelectric operations under the FERC licenses.

Threatened and Endangered Species and Wildlife

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

PGE 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 and the Federal Power Act. As a result of measures contained in their operating licenses, the Deschutes River and Willamette River projects have been certified as low impact hydro, with 50 MWa of their output included as part of the Company’s renewable energy portfolio used to meet the requirements of Oregon’s RPS. Conditions required with the operating licenses are expected to result in a minor reduction in power production and increase capital spending to modify the facilities to enhance fish passage and survival.

Avian Protection—Various statutory authorities as well as the Migratory Bird Treaty Act have established civil, criminal, and administrative penalties for the unauthorized take of migratory birds. Because PGE operates electric transmission lines and wind generation facilities that can pose risks to a variety of such birds, the Company is required to have an avian protection plan to reduce risks to bird species that can result from Company operations. PGE has developed and implemented such a plan for its transmission and distribution facilities and continues the process of developing a plan for its wind facilities.

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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 (CCBs), which have historically not been considered hazardous waste under the RCRA. The EPA continues to consider 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. A number of legislative initiatives and challenges are underway to limit or remove the EPA’s ability to regulate CCBs as hazardous waste. 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. The EPA lists PGE as a Potentially Responsible Party (PRP) on 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 and prompted the EPA to subsequently include Portland Harbor on the federal National Priority List as a Superfund site pursuant to CERCLA. The EPA initially listed sixty-nine PRPs, including PGE as it has historically owned or operated property near the river. In 2008, the EPA requested further information from various parties, including PGE, concerning property several miles beyond the original river segment and, as a result, the PRPs now number over one hundred. In March 2012, a draft feasibility study was submitted to the EPA for review and approval. A record of Decision is expected from the EPA in 2015 on the various clean-up alternatives, which, as outlined in the feasibility study, could take up to 28 years to complete and range in cost from $169 million to $1.8 billion. It is unclear for what portion, if any, that PGE might be held responsible.

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. In March 2012, the EPA approved the remedial investigation and stated that it intends to recommend no action on the site. A final Record of Decision is expected in March 2013.

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.”

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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 seeks to recover in customer prices most of the costs incurred in connection with the operation of its business, including, among other things, costs related to capital projects (such as the construction of new facilities or the modification of existing facilities), the costs of compliance with legislative and regulatory requirements and the costs of damage from storms and other natural disasters. However, there can be no assurance that such recovery will be granted. The OPUC has the authority to disallow the recovery of any costs that it considers imprudently incurred. Although the OPUC is required to establish customer prices that are fair, just and reasonable, it has significant discretion in the interpretation of this standard.

In February 2013, PGE filed with the OPUC a 2014 General Rate Case with a 2014 test year. For additional information regarding the 2014 General Rate Case, see the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations." 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. Under such circumstances, PGE attempts to manage its costs at levels consistent with the reduced price increases. However, if the Company is unable to do so, or if such cost management results in increased operational risk, the Company's financial and operating results could be adversely affected.

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

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

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

As part of its normal business operations, PGE purchases power and natural gas in the open market under short and long term contracts, which may specify variable-prices or volumes. Market prices for power and natural gas are influenced primarily by factors related to supply and demand. These factors generally include the adequacy of generating capacity, scheduled and unscheduled outages of generating facilities, hydroelectric 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

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be required to provide increased collateral, which could adversely affect the Company's liquidity. Conversely, if power and natural gas prices rise, especially during periods when the Company requires greater-than-expected volumes that must be purchased at market or short-term prices, PGE could incur greater costs than originally estimated.

The risk of volatility in power costs is partially mitigated through the 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 PCAM provides for a fixed deadband range of $15 million below, to $30 million above, baseline NVPC. Application of the PCAM requires that PGE absorb certain power cost increases before the Company is allowed to recover any amount from customers. Accordingly, the PCAM is expected to only partially mitigate the potentially adverse financial impacts of forced generating plant outages, reduced hydro and wind availability, interruptions in fuel supplies, and volatile wholesale energy prices.

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

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

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

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

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

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

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

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

Access to capital markets is important to PGE’s ability to operate its business and complete its capital projects. Credit rating agencies evaluate 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 ability to operate. The Company potentially faces significant capital requirements over the next two to five years and expects to issue debt and equity securities, as necessary, to fund these requirements. In addition, contractual commitments and regulatory requirements may limit the Company’s ability to delay or terminate certain projects. For additional information concerning PGE’s capital requirements, see “Capital Requirements” in the Liquidity and Capital Resources section in Item 7.—“Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

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

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.”

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Reduced stream flows and unfavorable wind conditions can adversely affect generation from 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 results of operations.

PGE derives a significant portion of its power supply from its own hydroelectric facilities and through long-term purchase contracts with certain public utility districts in the state of Washington. Regional rainfall and snow pack levels affect 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 results of operations.

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

Although the application of the PCAM could help mitigate adverse financial effects from any decrease in power provided by hydroelectric and wind 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) related to wind resources.

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

Future legislation or regulations could result in limitations on greenhouse gas emissions from the Company’s fossil fuel-fired generation facilities. Compliance with any greenhouse gas 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 potential greenhouse gas emissions reduction requirements is subject to significant uncertainties, including those related to: the timing of the implementation of emissions reduction rules; required levels of emissions reductions; requirements with respect to the allocation of emissions allowances; the maturation, regulation and commercialization of carbon capture and sequestration technology; and PGE’s compliance alternatives. Although the Company cannot currently estimate the effect of future legislation or regulations on its results of operations, financial condition or cash flows, the costs of compliance with such legislation or regulations could be material.

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

PGE currently has unsecured revolving credit facilities with several banks for an aggregate amount of $700 million. These 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 certain circumstances occur that could result in a material adverse change in the business, financial condition or results of operations of PGE, the Company may not be able to make such representations, in which case the banks would not be required to lend. PGE is also subject to the risk that one or more of the participating banks may default on their obligation to make loans under the credit facilities.

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

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

The Company is subject to state and federal requirements concerning air emissions and water discharges from thermal generation plants. For additional information, see the Environmental Matters section in Item 1.—"Business." These requirements could adversely affect the Company's results of operations by requiring (i) the installation of additional air emissions and water discharge controls at 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, which could adversely affect PGE's liquidity and results of operations.

Performance of the capital markets affects the value of assets that are held in trust to satisfy future obligations under 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 2012, 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 the pension plan's underfunded status from $147 million as of December 31, 2011 to $191 million as of December 31, 2012.

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

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

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.

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

A portion of PGE’s total energy requirement is supplied with power generated from hydroelectric and wind 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 operational changes to these projects. Salmon recovery plans could include further major operational changes to the region’s hydroelectric projects, including those owned by PGE and those from which the Company purchases power under long-term contracts. In addition, laws relating to the protection of migratory birds and other wildlife could impact the development and operation of transmission lines and wind projects. Also, new interpretations of existing laws and regulations could be adopted or become applicable to such facilities, which could further increase required expenditures for salmon recovery and endangered species protection and reduce the 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 and wires) is currently not available, however, the Company would likely seek recovery of large losses to such property through the ratemaking process.

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

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

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However, changes in regulations could delay or adversely affect business planning and transactions, and substantially increase the Company's costs.

PGE has a workforce with a significant number of employees approaching retirement.

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.

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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.

Generating Facilities

The following are generating facilities owned by PGE as of December 31, 2012:

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.

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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, 2012, PGE owned an electric transmission system consisting of approximately 700 circuit miles of 500-kV line and 400 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, a 4,800 MW transmission facility between John Day, in northern Oregon, and Malin, in southern Oregon near the California border. The California-Oregon AC Intertie is used primarily for the transmission of interstate purchases and sales of electricity among utilities, including PGE.

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

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

ITEM 3. LEGAL PROCEEDINGS.

Citizens' Utility Board of Oregon v. Public Utility Commission of Oregon and Utility Reform Project and Colleen O'Neill v. Public Utility Commission of Oregon, Public Utility Commission of Oregon 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.

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

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

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

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 June 2003, the FERC issued an order terminating the proceeding and denying the claims for refunds. Parties appealed various aspects of these FERC orders to the U.S. Ninth Circuit Court of Appeals (Ninth Circuit).

In August 2007, the Ninth Circuit issued its decision on appeal, concluding that the FERC failed to adequately explain how it considered or examined new evidence showing intentional market manipulation in California and the

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

In October 2011, the FERC issued an Order on Remand establishing an evidentiary hearing to determine whether any seller had engaged in unlawful market activity in the Pacific Northwest spot markets during the December 25, 2000 through June 20, 2001 period by violating specific contracts or tariffs, and, if so, whether a direct connection existed between the alleged unlawful conduct and the rate charged under the applicable contract. The FERC held that the Mobile-Sierra public interest standard governs challenges to the bilateral contracts at issue in this proceeding, and the strong presumption under Mobile-Sierra that the rates charged under each contract are just and reasonable would have to be specifically overcome before a refund could be ordered. The FERC directed the presiding judge, if necessary, to determine a refund methodology and to calculate refunds, but held that a market-wide remedy was not appropriate, given the bilateral contract nature of the Pacific Northwest spot markets. Certain parties claiming refunds filed requests for rehearing of the Order on Remand, 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 December 2012, the FERC issued an order granting an interlocutory appeal of the trial judge's ruling on the scope of the remand proceeding. In this order, the FERC held that its Order on Remand was not intended to alter the general state of the law regarding the Mobile-Sierra presumption. The FERC also held that the Mobile-Sierra presumption could be overcome either by (i) a showing that a respondent had violated a contract or tariff and that the violation had a direct connection to the rate charged under the applicable contract or (ii) a showing that the contract rate at issue imposed an excessive burden or seriously harmed the public interest.

In its October 2011 Order on Remand, the FERC held the hearing procedures in abeyance pending the results of settlement discussions, which it ordered be convened before a FERC settlement judge. Pursuant to the settlement proceedings, the Company received notice of two claims and reached agreements to settle both claims for an immaterial amount. The FERC approved both settlements during 2012.

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

The above-referenced settlements resulted in a release of the Company as a named respondent in the ongoing remand proceedings, which are limited to initial and direct claims for refunds, but there remains a possibility that additional claims could be asserted against the Company in future proceedings if refunds are ordered against current respondents.

ITEM 4. MINE SAFETY DISCLOSURES.

Not applicable.

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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 15, 2013, there were 1,040 holders of record of PGE’s common stock and the closing sales price of PGE’s common stock on that date was $28.98 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
2012			
Fourth Quarter	$28.08	$24.86	$0.270
Third Quarter	27.92	26.57	0.270
Second Quarter	26.94	24.25	0.270
First Quarter	25.62	24.29	0.265
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

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.

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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,				
	2012	2011	2010	2009	2008
	(In millions, except per share amounts)				
Statement of Income Data:					
Revenues, net	$1,805	$1,813	$1,783	$1,804	$1,745
Gross margin	60 %	58 %	54 %	48 %	50 %
Income from operations	$302	$309	$267	$208	$217
Net income	140	147	121	89	87
Net income attributable to Portland General Electric Company	141	147	125	95	87
Earnings per share—basic and diluted	1.87	1.95	1.66	1.31	1.39
Dividends declared per common share	1.075	1.055	1.035	1.010	0.970
Statement of Cash Flows Data:					
Capital expenditures	303	300	450	696	383

	As of December 31,				
	2012	2011	2010	2009	2008
	(Dollars in millions)				
Balance Sheet Data:					
Total assets	$5,670	$5,733	$5,491	$5,172	$4,889
Total long-term debt	1,636	1,735	1,808	1,744	1,306
Total Portland General Electric Company shareholders' equity	1,728	1,663	1,592	1,542	1,354
Common equity ratio	51.1 %	48.6 %	46.7 %	46.9 %	47.3 %

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

Forward-Looking Statements

The information in this report includes statements that are forward-looking within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements include, but are not limited to, statements that relate to expectations, beliefs, plans, assumptions and objectives concerning future and results of operations, business prospects, future loads, the outcome of litigation and regulatory proceedings, future capital expenditures, market conditions, future events or performance and other matters. Words or phrases such as "anticipates," "believes," "estimates," "expects," "intends," "plans," "predicts," "projects," "will likely result," "will continue," "should," or similar expr 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 proceedings, audits, investigations and actions, including those of the FERC and OPUC with respect to allowed rates of return, financings, electricity pricing and price structures, acquisition and disposal of facilities and other assets, construction and operation of plant facilities, transmission of electricity, recovery of power costs and capital investments, and current or prospective wholesale and retail competition;
- economic conditions that result in decreased demand for electricity, reduced revenue from sales of excess energy during periods of low wholesale market prices, impaired financial stability of vendors and service providers and elevated levels of uncollectible customer accounts;
- the outcome of legal and regulatory proceedings and issues including, but not limited to, the matters described in Note 18, Contingencies, in the Notes to Consolidated Financial Statements in Item 8.— "Financial Statements and Supplementary Data" of this Annual Report on Form 10-K;
- unseasonable or extreme weather and other natural phenomena, which could affect customer demand for power and PGE's ability and cost to procure adequate power and fuel supplies to serve its customers, and could increase the Company's costs to maintain its generating facilities and transmission and distribution systems;
- operational factors affecting PGE's power 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;
- the failure to complete capital projects on schedule and within budget or the abandonment of capital projects, which could result in the Company's inability to recover project costs;
- volatility in wholesale power and natural gas prices, which could require 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, 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 fuels, including natural gas, coal and oil, and the impact of such changes on the Company's power costs, and changes in the availability and price of wholesale power;
- changes in residential, commercial, and industrial customer growth, and in demographic patterns, in PGE's service territory;
- the effectiveness of PGE's risk management policies and procedures and the creditworthiness of customers and counterparties;
- declines in the fair value of equity securities held for the defined benefit pension plans and other benefit plans, which could result in increased funding requirements for such plans;
- changes in, and compliance with, environmental and endangered species laws and policies;
- the effects of climate change, including changes in the environment that may affect energy costs or consumption, increase the Company's costs, or adversely affect its operations;
- new federal, state, and local laws that could have adverse effects on operating results;
- cyber security attacks, data security breaches, or other malicious acts that cause damage to the Company's generation and transmission facilities or information technology systems, or result in the release of confidential customer and proprietary information;
- employee workforce factors, including a significant number of employees approaching retirement, potential strikes, work stoppages, and transitions in senior management;
- political, economic, and financial market conditions;
- natural disasters and other risks, such as earthquake, flood, drought, lightning, wind, and fire;
- financial or regulatory accounting principles or policies imposed by governing bodies; and
- acts of war or terrorism.

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

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Overview

Operating Activities—PGE is a vertically integrated electric utility engaged in the generation, transmission, distribution, and retail sale of electricity in the state of Oregon, as well as the wholesale purchase and sale of electricity and natural gas in the United States and Canada. The Company generates revenues and cash flows primarily from the 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. Changes in retail prices for electricity and in customer usage patterns (which can be affected by the economy) also have an effect on revenues, while the availability and price of power and fuel can affect income from operations. PGE is a winter-peaking utility that typically experiences its highest retail energy demand during the winter heating season, with a slightly lower peak in the summer that generally results from air conditioning demand.

Customers and Demand—The majority of the Company's customers are located within the Portland and Salem, Oregon metropolitan areas. The December 2012 seasonally adjusted unemployment rate for the Portland area was 7.4%, while the state of Oregon was 8.4%, compared with the national average of 7.8%. The state of Oregon forecasts that the average Oregon unemployment rate will remain slightly above the national average at 8.1% for 2013.

Retail energy deliveries, as shown in the table below, decreased 0.8% in 2012 from the 2011 level reflecting the effect of cooler weather during the heating season in 2011 while more normal seasonal weather conditions prevailed during 2012. This weather impact is most evident with decreased deliveries to residential customers, despite the growth in the number of customers served. 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.

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

	2012 Average Number of Customers	Energy Deliveries *	2011 Average Number of Customers	Energy Deliveries *	Increase/ (Decrease) in Energy Deliveries	
Residential	723,440	7,505	719,977	7,733	(2.9	)%
Commercial	103,766	7,402	102,940	7,419	(0.2	)
Industrial	261	4,283	255	4,193	2.1	
Total	827,467	19,190	823,172	19,345	(0.8	)%

* In thousands of MWh.

Adjusted for the effects of weather, total retail energy deliveries in 2012 increased 0.6% compared to 2011. PGE projects that retail energy deliveries for 2013 will increase in the range of 0.5% to 1.0% from 2012 weather adjusted levels, after allowing for energy efficiency and conservation efforts.

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

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Plant availability is impacted by planned maintenance and forced outages, during which the respective plant is unavailable to provide power. PGE's thermal generating plants require varying levels of annual maintenance, which is generally performed during the second quarter of the year. More extensive planned service maintenance was performed in 2011, compared to 2012 and 2010. Availability of the plants PGE operates approximated 94%, 93%, and 95% for the years ended December 31, 2012, 2011, and 2010, respectively, with the availability of Colstrip, which PGE does not operate, approximating 93%, 84%, and 95%, respectively.

During the year ended December 31, 2012, the Company's generating plants provided approximately 50% of its retail load requirement, compared to 48% in 2011 and 64% in 2010. The lower relative volume of power generated to meet the Company's retail load requirement during 2012 and 2011 was primarily due to the economic displacement of thermal generation by energy received from hydro resources and lower-cost purchased power.

Energy received from PGE-owned hydroelectric plants and under contracts from mid-Columbia hydroelectric projects decreased 24% in 2012 compared to 2011, primarily due to the expiration of a contract at the end of 2011 representing approximately 156 MW of capacity. These resources provided approximately 19% of the Company's retail load requirement for 2012, compared with 25% for 2011 and 23% for 2010. Energy received from these sources exceeded projections (or "normal") included in the Company's Annual Power Cost Update Tariff (AUT) by approximately 11% during 2012 and 13% during 2011, compared to falling short of such projections by approximately 8% during 2010. Such projections, which are finalized with the OPUC in November each year, establish the power cost component of retail prices for the following calendar year. "Normal" represents the level of energy forecasted to be received from hydroelectric resources for the year and is based on average regional hydro conditions. Any excess in hydro generation from that projected in the AUT generally displaces power from higher cost sources, while any shortfall is generally replaced with power from higher cost sources. Based on recent forecasts of regional hydro conditions in 2013, energy from hydro resources is expected to be below normal for 2013.

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 20% in 2012, 13% in 2011 and 27% in 2010.

Pursuant to the Company's 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," which ranges from $15 million below to $30 million above baseline NVPC. To the extent actual NVPC is above or below the deadband, the PCAM provides for 90% of the variance to be collected from or refunded to customers, respectively, subject to a regulated earnings test. The following is a summary of the impacts of the PCAM for 2012, 2011 and 2010.

- For 2012, actual NVPC was $17 million below baseline NVPC, and $2 million above the lower deadband threshold, resulting in a potential refund due to customers. However, based on results of the regulated earnings test, no estimated refund to customers was recorded as of December 31, 2012.
- For 2011, actual NVPC was $34 million below baseline NVPC, which is $19 million above the lower deadband threshold, resulting in a potential refund to customers. As of December 31, 2011, PGE recorded an estimated refund to customers of approximately $10 million, which was reduced from the potential refund based on the application of the regulated earnings test. During 2012, the estimated refund to customers was further reduced to $6 million after the application of an updated regulated earnings test.
- For 2010, actual NVPC was approximately $12 million below baseline NVPC, but within the established deadband range; accordingly, no refund to customers was recorded as of December 31, 2010.

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

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

General Rate Case—On February 15, 2013, PGE filed with the OPUC a 2014 General Rate Case, which is based on a 2014 test year. PGE requested a $105 million increase in annual revenues, representing an approximate 6% overall increase in customer prices. The requested increase includes improvements to existing power plants and wind forecasting, new Clackamas River fish-sorting facilities, a disaster-preparedness center, technology investments, employee benefit costs and compliance with new federal regulations. In addition, PGE is proposing a capital structure of 50% debt and 50% equity, a return on equity of 10%, a cost of capital of 7.86%, and an average rate base of approximately $3.1 billion.

Regulatory review of the 2014 General Rate Case will continue throughout 2013, with a final order expected to be issued by the OPUC by mid-December 2013. New customer prices are expected to become effective January 1, 2014.

Capital Requirements and Financing—PGE's capital requirements of $303 million in 2012 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. During 2012, cash from operations of $494 million funded the Company's capital requirements and the redemption of $100 million of long-term debt.

Capital expenditures in 2013 are expected to approximate $514 million, which includes $161 million related to the new natural gas-fired capacity resource, Port Westward Unit 2, and $8 million related to the Cascade Crossing transmission project described below. This estimate excludes additional costs, described below, that may be required in connection with the outcome of the Company's RFPs for energy and renewable resources:

Power Resources—In accordance with PGE's IRP and pursuant to the OPUC's competitive bidding guidelines, the Company issued two RFPs during 2012 for additional generation resources - one for capacity and energy (baseload) resources and one for renewable resources.

The RFP for capacity and energy resources is seeking, in addition to capacity and flexible peaking resources, approximately 300 MW to 500 MW of baseload energy resources. PGE has evaluated the energy resource bids received, and has developed a short list of bids for negotiation, with final resource selection expected by mid-2013. The baseload energy resources are expected to be available in the 2014 to 2017 timeframe.

The RFP for renewable resources is seeking approximately 100 MWa of renewable resources, which would be expected to be available to meet PGE's 2015 requirements under Oregon's renewable energy standard. The Company is evaluating the renewable resources bids received, and expects a final short list in early March 2013, with final resource selection by mid-2013.

An independent evaluator selected by the OPUC is helping conduct the RFPs and reviewing bids to ensure an objective and impartial process.

Transmission Capacity—Pursuant to the Company's IRP, PGE has been in the process of developing new transmission capacity from Boardman, Oregon to Salem, Oregon, under a project known as Cascade Crossing Transmission Project, or "Cascade Crossing." This project was originally proposed as a 215-mile, 500 kV transmission project to help meet future electricity demand. As PGE has worked with BPA in the formulation of the project and potential partnerships, the scope of the project has evolved. In January 2013, the Company entered into a Memorandum of Understanding (MOU) with BPA to pursue modifications to PGE's originally proposed project. Under this modified proposal, the transmission line would terminate at a new substation called Pine Grove, near Maupin, Oregon (approximately midway between Boardman and Salem), eliminating construction of approximately 101 miles of the originally proposed transmission line. This modification would avoid most impacts to the Confederated Tribes of Warm Springs Reservation, the

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Mt. Hood and Willamette national forests, and private forest and agricultural land in Marion and Linn Counties, and would reduce land acquisition, construction and environmental impacts, as well as resulting mitigation costs.

In addition to construction of the new transmission line, PGE would build the new Pine Grove substation, install series capacitors on existing BPA transmission lines and make other enhancements to the regional grid that would increase transmission capacity. In return, PGE would receive certain transmission capacity rights from BPA, with the details of such rights subject to further negotiation. The MOU also provides for the parties to negotiate an exchange whereby PGE would obtain from BPA ownership of additional transmission capacity in exchange for ownership and/or rights to certain PGE assets. Subject to the outcome of negotiations, the modified proposal would provide PGE a total of up to 2,600 MWs of transmission capacity that could be staged to come on-line in phases as needed,

Construction of the new transmission line from Boardman to the Pine Grove substation could start as early as 2017, with an estimated construction period of at least two years. As the parties continue negotiation of the terms and conditions of the modified proposal, the estimated costs and timeline of the project will be clarified. However, PGE expects the cost of the full project scope, as modified, to be at least $800 million.

For additional information concerning PGE’s IRP and the projects discussed above, see “Future Energy Resource Strategy” in the Power Supply section of Item 1.—“Business” and “Capital Requirements” in the Liquidity and Capital Resources section in this Item 7.

For 2013, PGE expects to fund estimated capital requirements and contractual maturities of $100 million of long-term debt with cash from operations, short-term debt, or long-term financings. Cash from operations is expected to approximate $468 million for 2013. The Company expects that the timing and amount of future issuances of debt and equity securities will depend primarily on the outcome of the Company’s RFPs for energy and renewable resources, as well as the timing and scope of Cascade Crossing. For further information, see the Liquidity and Debt and Equity Financings sections of this Item 7.

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

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

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

The following discussion highlights certain regulatory items, which have impacted the Company’s revenues, results of operations, or cash flows for 2012, or have affected customer prices, as authorized by the OPUC. In some cases, the Company deferred the related expenses or benefits as regulatory assets or liabilities, respectively, for later amortization and inclusion in customer prices, pending OPUC review and authorization:

Boardman Operating Life Adjustment—In PGE’s 2011 General Rate Case, the OPUC 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 Boardman over a shortened operating life. Pursuant to the tariff, the OPUC approved recovery of increased depreciation expense reflecting a change in the retirement date of Boardman from 2040 to 2020, with new prices effective July 1, 2011. The tariff also provides for annual updates to the revenue requirements with revised prices to take effect each January 1.

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Power Costs—Pursuant to the AUT process, PGE files annually an estimate of power costs for the following year. In the event a general rate case is filed in any given year, forecasted power costs would be included in such filing. In November 2011, the OPUC issued an order on the 2012 AUT resulting in an estimated decrease in customer prices as a result of expected lower power costs. The new prices became effective January 1, 2012 and were expected to result in a decline of approximately $22 million in annual revenues compared to 2011. Actual net variable power costs for 2012 were $17 million below what was expected in the AUT.

The 2013 AUT filing, which forecast power costs for 2013 to be lower than 2012, was approved by the OPUC and became effective January 1, 2013, with an expected reduction in annual revenues of $36 million.

In July 2012, the Company submitted to the OPUC the results of its PCAM for 2011 based on an updated regulated earnings test, which resulted in a refund to customers of approximately $6 million. In October 2012, the OPUC issued an order approving the refund, with the impact to customer prices effective January 1, 2013. For further information, see “Power Operations” in the Operating Activities section of this Overview, above.

Renewable Resource Costs—Pursuant to a renewable adjustment clause (RAC) mechanism, PGE can recover in customer prices prudently incurred costs of renewable resources that are expected to be placed in service in the current year. The Company may submit a filing to the OPUC by April 1st each year, with prices 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.

In March 2012, PGE submitted, and the OPUC subsequently approved, a filing for the installation of a small solar facility that requested a nominal credit to customer prices for a one-year period that began January 1, 2013, resulting from the gain on the sale and lease-back transaction directly related to the project.

Decoupling Mechanism—The decoupling mechanism, which is currently authorized through 2013, is intended to provide for recovery of margin lost as a result of a reduction in electricity sales attributable to energy efficiency and conservation efforts by residential and certain commercial customers. The mechanism provides for collection from (or refund to) customers if weather adjusted use per customer is less (or more) than that projected in the Company’s most recent general rate case. Collection or refund is expected to occur over one-year periods, which begin June 1 of the following year. For the year ended December 31, 2012, the Company recorded an estimated refund of $1 million, which resulted primarily from slightly higher weather adjusted use per customer than that projected in the 2011 General Rate Case.

Capital deferral—In the 2011 General Rate Case, the OPUC authorized the Company to defer the costs associated with four capital projects that were not completed at the time the 2011 General Rate Case was approved. A regulatory asset of $15 million was recorded in 2012, for potential recovery in customer prices, subject to an earnings test, with an offsetting credit to Depreciation and amortization expense. The Company expects to submit a filing to the OPUC by mid-2013 for recovery of the deferral, with a resulting tariff effective January 1, 2014.

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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,								
	2012			2011			2010		
	Amount	As % of Rev		Amount	As % of Rev		Amount	As % of Rev	
Revenues, net	$1,805	100	%	$1,813	100	%	$1,783	100	%
Purchased power and fuel	726	40		760	42		829	46	
Gross margin	1,079	60		1,053	58		954	54	
Operating expenses:									
Production and distribution	211	12		201	11		174	10	
Administrative and other	216	12		218	12		186	11	
Depreciation and amortization	248	14		227	13		238	13	
Taxes other than income taxes	102	5		98	5		89	5	
Total operating expenses	777	43		744	41		687	39	
Income from operations	302	17		309	17		267	15	
Other income:									
Allowance for equity funds used during construction	6	—		5	—		13	1	
Miscellaneous income, net	4	—		1	—		4	—	
Other income, net	10	—		6	—		17	1	
Interest expense	108	6		110	6		110	6	
Income before income taxes	204	11		205	11		174	10	
Income taxes	64	3		58	3		53	3	
Net income	140	8		147	8		121	7	
Less: net loss attributable to noncontrolling interests	(1)	—		—	—		(4)	—	
Net income attributable to Portland General Electric Company	$141	8	%	$147	8	%	$125	7	%

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

	Years Ended December 31,								
	2012			2011			2010		
Revenues[1] (dollars in millions):									
Retail:									
Residential	$860	48	%	$877	48	%	$803	45	%
Commercial	633	34		635	35		601	34	
Industrial	226	13		226	13		221	12	
Subtotal	1,719	95		1,738	96		1,625	91	
Other accrued (deferred) revenues, net	4	—		(16)	(1)		39	2	
Total retail revenues	1,723	95		1,722	95		1,664	93	
Wholesale revenues	49	3		60	3		87	5	
Other operating revenues	33	2		31	2		32	2	
Total revenues	$1,805	100	%	$1,813	100	%	$1,783	100	%
Energy deliveries[2] (MWh in thousands):									
Retail:									
Residential	7,505	35	%	7,733	36	%	7,452	35	%
Commercial	7,402	35		7,419	35		7,277	34	
Industrial	4,283	20		4,193	19		4,004	19	
Total retail energy deliveries	19,190	90		19,345	90		18,733	88	
Wholesale energy deliveries	2,249	10		2,142	10		2,580	12	
Total energy deliveries	21,439	100	%	21,487	100	%	21,313	100	%
Average number of retail customers:									
Residential	723,440	87	%	719,977	87	%	717,719	88	%
Commercial	103,766	13		102,940	13		102,282	12	
Industrial	261	—		255	—		265	—	
Total	827,467	100	%	823,172	100	%	820,266	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.

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

	Years Ended December 31,								
	2012			2011			2010		
Sources of energy (MWh in thousands):									
Generation:									
Thermal:									
Coal	3,610	17	%	4,125	19	%	4,984	23	%
Natural gas	2,882	14		2,138	10		4,460	21	
Total thermal	6,492	31		6,263	29		9,444	44	
Hydro	1,943	9		1,933	9		1,830	9	
Wind	1,125	5		1,216	6		833	4	
Total generation	9,560	45		9,412	44		12,107	57	
Purchased power:									
Term	7,382	35		6,252	29		3,984	19	
Hydro	1,728	8		2,897	13		2,417	11	
Wind	319	1		269	1		297	1	
Spot	2,285	11		2,763	13		2,618	12	
Total purchased power	11,714	55		12,181	56		9,316	43	
Total system load	21,274	100	%	21,593	100	%	21,423	100	%
Less: wholesale sales	(2,249	)		(2,142	)		(2,580	)	
Retail load requirement	19,025			19,451			18,843		

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

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 retail 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, actual NVPC was $34 million below baseline NVPC in 2011, compared to $12 million in 2010. Offsetting these increases to net income were higher employee-related costs.

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2012 Compared to 2011

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

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

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

- A $15 million decrease related to changes in the average retail price, resulting primarily from tariff changes effective January 1, 2012 as authorized by the OPUC including lower anticipated power costs included in the AUT partially offset by a $7 million net annual increase related to the tariff for recovery of Boardman over a shortened operating life. Incremental revenues under the Boardman tariff for the full year 2012 were $14 million compared with $7 million for the last six months of 2011.

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

	Heating Degree-Days		Cooling Degree-Days	
	2012	2011	2012	2011
1st Quarter	1,967	1,974	—	—
2nd Quarter	709	946	40	16
3rd Quarter	58	51	395	346
4th Quarter	1,435	1,679	1	—
Full Year	4,169	4,650	436	362
15-year Full Year average	4,235	4,219	456	464

On a weather adjusted basis, retail energy deliveries in 2012 increased 0.6% compared to 2011. Deliveries to residential, commercial, and industrial customers increased by 0.4%, 0.2%, and 1.7%, respectively. PGE projects that retail energy deliveries for 2013 will increase in the range of 0.5% to 1.0% from 2012 weather adjusted levels, after allowing for energy efficiency and conservation efforts.

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

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In 2012, wholesale revenues decreased $11 million, or 18%, from 2011 levels as a result of the net effect of the following:

- A $14 million decrease related to a 22% decline in the average wholesale price the Company received, driven by lower electricity market prices due to the relatively low price of natural gas and a surplus of hydro generation in the region; partially offset by

- A $3 million increase due to a 5% increase 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 2012, Purchased power and fuel expense decreased $34 million, or 4%, from 2011, with $19 million related to a 3% decrease in average variable power cost and $11 million related to a 1% decrease in total system load. The average variable power cost was $34.25 per MWh in 2012 compared to $35.15 per MWh in 2011. Actual NVPC was $17 million below baseline NVPC established in the AUT for 2012, compared with $34 million below baseline NVPC in 2011.

The mix of the decrease in Purchased power and fuel expense largely consisted of:

- A $49 million decrease in the cost of purchased power, consisting of $30 million related to a 6% decrease in average cost and $19 million related to a 4% decrease in purchases. The decrease in average cost was primarily driven by lower wholesale power prices resulting from favorable hydro conditions and low natural gas prices; partially offset by

- A $19 million increase in the cost of generation, primarily due to an increase in the proportion of power provided by the Company’s natural gas-fired generating plants, meeting 15% of PGE’s retail load requirement in 2012 compared to 11% in 2011. Energy from natural gas-fired generation increased 35% and the average cost of such generation decreased 16% on lower natural gas prices. The average cost of power generated increased 5% in 2012 compared to 2011.

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

Hydroelectric energy, from PGE-owned hydroelectric projects and from mid-Columbia projects combined, decreased 24% during 2012 from 2011, which was primarily the result of the expiration of a contract related to a mid-Columbia project that represented approximately 156 MW of capacity. Favorable hydro conditions in both 2012 and 2011 resulted in total hydroelectric energy received for each respective year exceeding that projected in the Company’s AUT by approximately 11% for 2012 and 13% for 2011. Based on recent forecasts of regional hydro conditions in 2013, energy from hydro resources is expected to be below normal levels.

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The following table indicates the forecast of the April-to-September 2013 runoff (issued February 18, 2013) compared to the actual runoffs for 2012 and 2011 (as a percentage of normal, as measured over the 30-year period from 1971 through 2000):

Location	Runoff as a Percent of Normal * 2013 Forecast		2012 Actual		2011 Actual	
Columbia River at The Dalles, Oregon	89	%	126	%	135	%
Mid-Columbia River at Grand Coulee, Washington	90		129		123	
Clackamas River at Estacada, Oregon	98		133		135	
Deschutes River at Moody, Oregon	92		118		120	

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

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 60% in 2012 compared to 58% in 2011. The increase in Gross margin was largely due to certain regulatory items that reduced gross margin in 2011. During 2011, PGE provided customers certain tax credits in the amount of $18 million and recorded an estimated refund to customers of $10 million related to the PCAM, both of these regulatory items reduced gross margin for 2011.

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

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

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

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

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

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

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

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

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

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

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;

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- 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 (Senate Bill 408) primarily due to an adjustment recorded in 2010 that pertained to the 2009 liability, which was included in Other accrued revenues. Senate Bill 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.

Wholesale revenues in 2011 decreased $27 million, or 31%, from 2010 as a result of the following:

- A $14 million decrease due to a 17% decline in wholesale energy sales volume; and
- 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.

Purchased power and fuel expense decreased $69 million, or 8%, in 2011 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 and $38.68 per MWh in 2010.

The mix of 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

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average cost was primarily driven by lower wholesale power prices resulting from favorable hydro conditions.

Energy received 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 August 2010 completion of the third and final phase of Biglow Canyon 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.

For 2011, energy received from PGE-owned hydroelectric plants and under contracts from mid-Columbia projects exceeded that projected in the Company’s 2011 AUT by 13% and 14% compared to 2010. For 2010, energy received from these hydroelectric resources fell short of projections included in the Company’s 2010 AUT by approximately 8%.

Actual NVPC was $34 million below baseline NVPC in 2011, compared with $12 million below baseline NVPC in 2010.

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 customers 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;

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- 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 interests through the Net loss attributable to the noncontrolling interest. 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”; partially offset by
- A $21 million increase in depreciation related to the August 2010 completion of the third and final phase of Biglow Canyon wind farm, 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 was 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 third and final phase of Biglow Canyon wind farm; 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, primarily driven by the August 2010 completion of the third and final phase of Biglow Canyon wind farm, 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% in 2011 and 30.3% in 2010) 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 farm, 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 impairment losses recognized on the photovoltaic solar power facilities, discussed previously in Depreciation and amortization.

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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 2012 and future debt maturities and projected cash requirements for 2013 through 2017 (in millions, excluding AFDC):

	Years Ending December 31,						
	2012		2013	2014	2015	2016	2017
Ongoing capital expenditures	$263		$322	$285	$253	$262	$245
Port Westward Unit 2	1		161	107	33	—	—
Hydro licensing and construction	22		23	28	28	1	—
Cascade Crossing	24		8	—	—	—	—
Total capital expenditures	$310	(1)	$514	$420	$314	$263	$245
Long-term debt maturities	$100		$100	$—	$70	$67	$58

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

Ongoing capital expenditures—Consists of upgrades to and replacement of transmission, distribution, and generation infrastructure as well as new customer connections. Included in the amounts presented is approximately $13 million in expected capital expenditures for emissions controls at Boardman in 2013.

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, amounted to $5 million in 2012. Included in Ongoing capital expenditures in the table above are approximately $3 million of Preliminary engineering the Company expects that it will spend in 2013.

Port Westward Unit 2—In January 2013, PGE's Port Westward Unit 2 (PW2) flexible generating resource was selected as the successful bid for the capacity resource in the Company's RFP for energy and capacity resources. PW2 is a 220 MW natural gas-fired plant that will be located near PGE's Port Westward and Beaver natural gas-fired plants near Clatskanie, Oregon. Total cost of PW2 is estimated between $300 million and $310 million, excluding AFDC, and the facility is expected to be online in 2015.

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.

Integrated resource plan—Pursuant to the energy and capacity RFP issued in 2012 in accordance with the Company's IRP, PGE is in negotiations with the top bidder from the short list of winning projects for energy resources, which include power purchase agreements and PGE-ownership options. The successful bidder for the energy resources component of this RFP is expected to be selected by mid-2013. A second RFP for approximately 100 MWa of renewable resources was issued in 2012, for which the Company expects the successful bidders to be selected by mid-2013. Selection of, and negotiations with, the successful bidders for the energy and renewable resources will clarify timing and total cost of these projects.

In addition, the Company continues to work with stakeholders in the development of, and the formation of potential partnerships for Cascade Crossing, to provide additional transmission capacity from northeastern Oregon to PGE's service territory. As of December 31, 2012, approximately $46 million is included in construction work-in-progress related to this project. As the parties continue negotiations of the terms and conditions of the modified proposal, the estimated costs and timeline of the project will be clarified.

Due to the uncertainty of these IRP projects, the Capital Requirements table presented at the beginning of this section does not include estimates for any amounts related to these projects beyond 2013.

For further information on the Company's IRP, including the projects subject to the RFP process or Cascade Crossing, see "Future Energy Resource Strategy" in the Power Supply section and the Transmission and Distribution section contained in Item 1.—"Business" and "Capital Requirements and Financing" in the Overview section of this Item 7.

Liquidity

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

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

	Years Ended December 31,		
	2012	2011	2010
Cash and cash equivalents, beginning of year	$6	$4	$31
Net cash provided by (used in):			
Operating activities	494	453	391
Investing activities	(294)	(299)	(430)
Financing activities	(194)	(152)	12
Net change in cash and cash equivalents	6	2	(27)
Cash and cash equivalents, end of year	$12	$6	$4

2012 Compared to 2011

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

Cash provided by operations includes the recovery in customer prices non-cash charges for depreciation and amortization. The Company estimates that such charges will approximate $244 million in 2013. Combined with all other sources, cash provided by operations is estimated to be approximately $468 million in 2013. This estimate anticipates no change in margin deposits held by brokers as of December 31, 2012, which is based on both the timing of contract settlements and projected energy prices. The remaining $224 million in estimated cash flows from operations in 2013 is expected from normal operating activities.

Cash Flows from Investing Activities—Cash flows used in investing activities consist primarily of capital expenditures related to new construction and improvements to PGE's distribution, transmission, and generation facilities. The $5 million decrease in net cash used in investing activities in 2012 compared to 2011 was primarily due to proceeds received in the amount of $10 million for the sale of a solar power facility during the first quarter of 2012, partially offset by a 1% increase in capital expenditures.

The Company plans approximately $514 million of capital expenditures in 2013 related to upgrades to and replacement of transmission, distribution and generation infrastructure, including $161 million related to the construction of Port Westward Unit 2, a new natural gas-fired generating resource. PGE plans to fund the 2013 capital expenditures with the cash expected to be generated from operations during 2013, as discussed above, as well as with short-term debt and long-term financings. For additional information, see "Capital Requirements" in the Liquidity and Capital Resources section of this Item 7.

Cash Flows from Financing Activities—Financing activities provide supplemental cash for both day-to-day operations and capital requirements as needed. During 2012, net cash used in financing activities consisted of the repayment of long-term debt of $100 million, the payment of dividends of $81 million and net maturities of commercial paper of $13 million. During 2011, net cash used in financing activities primarily consisted of the payment of dividends of $79 million and the repayment of long-term debt of $80 million, including the premium paid, partially offset by net issuances of commercial paper of $11 million.

2011 Compared to 2010

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Cash Flows from Operating Activities—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 VEBAs in 2011. The VEBAs fund the benefits of the Company’s noncontributory postretirement health and life insurance plans.

Cash Flows from Investing Activities—The $131 million decrease in cash used in investing activities in 2011 compared to 2010 was due to lower capital expenditures of $150 million due to decreased construction costs related to the completion of Biglow Canyon Phase III in August 2010, as well as the effect of a $19 million distribution from the Nuclear decommissioning trust to PGE in 2010.

Cash Flows from Financing Activities—During 2011, net cash used in financing activities primarily consisted of the payment of dividends of $79 million and the repayment of 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 consisted primarily 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.

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Dividends on Common Stock

The following table indicates common stock dividends declared in 2012:

Declaration Date	Record Date	Payment Date	Declared Per Common Share
February 22, 2012	March 26, 2012	April 16, 2012	$0.265
May 23, 2012	June 25, 2012	July 16, 2012	0.270
August 2, 2012	September 25, 2012	October 15, 2012	0.270
November 7, 2012	December 26, 2012	January 15, 2013	0.270

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 20, 2013, the Board of Directors declared a dividend of $0.27 per share of common stock to stockholders of record on March 25, 2013, payable on or before April 15, 2013.

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	Positive	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 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, 2012, PGE had posted approximately $91 million of collateral with these counterparties, consisting of $46 million in cash and $45 million in letters of credit, $18 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, 2012, the approximate amount of additional collateral that could be requested upon a single agency downgrade to below investment grade is approximately $83 million and decreases to approximately $27 million by December 31, 2013. The amount of additional collateral that could be requested upon a dual agency downgrade to below investment grade is approximately $253 million and decreases to approximately $92 million by December 31, 2013.

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.

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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, 2012, under the most restrictive issuance test in the Indenture of Mortgage and Deed of Trust, the Company could have issued up to approximately $703 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, 2012, the Company’s debt ratio, as calculated under the credit agreements, was 48.9%.

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. For 2013, PGE expects to fund estimated capital requirements and contractual maturities of $100 million of long-term debt with cash from operations, short-term debt, or long-term financings. The Company expects that the timing and amount of future issuances of debt and equity securities in the next 5 years will depend primarily on the outcome of the Company’s RFPs for energy and renewable resources under its IRP, as well as the timing and scope of Cascade Crossing.

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 $400 million syndicated credit facility, which is scheduled to terminate in November 2017; and

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- 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, 2012, PGE had no borrowings outstanding under the credit facilities, with $17 million of commercial paper outstanding and $67 million of letters of credit issued. As of December 31, 2012, the aggregate unused available credit under the credit facilities was $616 million.

Long-term Debt. During 2012, $100 million of First Mortgage Bonds matured and were redeemed. As of December 31, 2012, total long-term debt outstanding was $1,636 million, with $100 million scheduled to mature in 2013, consisting of $50 million due on each of April 1 and August 1. 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 51.1% and 48.6% as of December 31, 2012 and 2011, respectively.

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Contractual Obligations and Commercial Commitments

The following indicates PGE's contractual obligations as of December 31, 2012 (in millions):

	2013	2014	2015	2016	2017	There-after	Total
Long-term debt	$100	$—	$70	$67	$58	$1,341	$1,636
Interest on long-term debt (1)	92	89	87	83	81	1,025	1,457
Capital and other purchase commitments	81	10	11	9	2	72	185
Purchased power and fuel:							
Electricity purchases	154	83	82	64	36	440	859
Capacity contracts	21	21	20	19	—	—	81
Public Utility Districts	8	8	8	7	5	25	61
Natural gas	55	26	21	12	10	6	130
Coal and transportation	22	9	—	—	—	—	31
Pension plan contributions	—	15	32	44	44	64	199
Operating leases	9	9	9	10	11	186	234
Total	$542	$270	$340	$315	$247	$3,159	$4,873

(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, 2012.

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 incurred costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited or refunded to customers through the ratemaking process. Regulatory accounting is appropriate as long as prices are established or subject to approval by independent third-party regulators; prices are designed to recover the specific enterprise's cost of service; and in view of demand for service, it is reasonable to assume that prices set at levels that will recover costs can be charged to and collected from customers. Amortization of regulatory assets and liabilities is reflected in the statement of income over the period in which they are included in customer prices.

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

Asset Retirement Obligations

PGE recognizes 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.

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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 loss contingency is accrued, and disclosed if material, when it is probable that an asset has been impaired or a liability incurred and the amount of the loss can be reasonably estimated. If a range of probable loss is established, the minimum amount in the range is accrued, unless some other amount within the range appears to be a better estimate. If the probable loss cannot be reasonably estimated, no accrual is recorded, but the loss contingency is disclosed to the effect that it cannot be reasonably estimated. Material loss contingencies are disclosed when it is reasonably possible that an asset has been impaired or a liability incurred. Established accruals reflect management's assessment of inherent risks, credit worthiness, and complexities involved in the process. There can be no assurance as to the ultimate outcome of any particular contingency.

Price Risk Management

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

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

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

Pension Plan

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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. PGE capitalizes a portion of pension expense based on the proportion of labor costs capitalized.

Changes in actuarial assumptions can also have a material effect on net periodic pension expense. A 0.25% reduction in the expected long-term rate of return on plan assets, or reduction in the discount rate, would have the effect of increasing the 2012 net periodic pension expense by approximately $2 million.

Discount rates applied to the pension liability have continued to decline due to general macroeconomic and credit market conditions. The Federal Reserve Board’s continued low interest rate policy and the general preference in the financial markets for the safety of high-quality bonds has continued to drive the rates on high-quality bonds down throughout 2012, which lowers the discount rate used to measure the pension liability.

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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; financial swap and futures agreements, which may require payments to, or receipt of payments from, counterparties based on the differential between a fixed and variable price for the commodity; and option contracts to mitigate risk that arises from market fluctuations of commodity prices. PGE does not engage in trading activities for non-retail purposes.

The following table presents energy commodity derivative fair values as a net liability as of December 31, 2012 that are expected to settle in each respective year (in millions):

	2013	2014	2015	Total
Commodity contracts:				
Electricity	$43	$28	$10	$81

Natural gas	80	27	6	113
	$123	$55	$16	$194

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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, 2012, a 10% change in the value of the Canadian dollar would result in an immaterial change in exposure for transactions that will settle over the next twelve months.

Interest Rate Risk

To meet short-term cash requirements, PGE has established a program under which it may from time to time issue commercial paper for terms of up to 270 days; such issuances are supported by the Company’s unsecured revolving credit facilities. Although any borrowings under the commercial paper program subject the Company to fluctuations in interest rates, reflecting current market conditions, individual instruments carry a fixed rate during their respective terms. As of December 31, 2012, PGE had no borrowings outstanding under its revolving credit facilities and $17 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, 2012, the total fair value and carrying amounts by maturity date of PGE’s long-term debt are as follows (in millions):

	Total	Carrying Amounts by Maturity Date						
	Fair Value	Total	2013	2014	2015	2016	2017	There-after
First Mortgage Bonds	$1,811	$1,515	$100	$—	$70	$67	$58	$1,220
Pollution Control Revenue Bonds	138	121	—	—	—	—	—	121
Total	$1,949	$1,636	$100	$—	$70	$67	$58	$1,341

As of December 31, 2012, 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

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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, 2012, PGE's credit risk exposure is $3 million for commodity activities with externally-rated investment grade counterparties and matures in 2013. 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:

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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, 2012 and 2011, 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, 2012. We also have audited the Company's internal control over financial reporting as of December 31, 2012, 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.

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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, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, 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, 2012, 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 21, 2013

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

	Years Ended December 31,		
	2012	2011	2010
Revenues, net	$1,805	$1,813	$1,783
Operating expenses:			
Purchased power and fuel	726	760	829
Production and distribution	211	201	174
Administrative and other	216	218	186
Depreciation and amortization	248	227	238
Taxes other than income taxes	102	98	89
Total operating expenses	1,503	1,504	1,516
Income from operations	302	309	267
Other income:			
Allowance for equity funds used during construction	6	5	13
Miscellaneous income, net	4	1	4
Other income, net	10	6	17
Interest expense	108	110	110
Income before income taxes	204	205	174
Income taxes	64	58	53
Net income	140	147	121
Less: net loss attributable to noncontrolling interests	(1)	—	(4)
Net income attributable to Portland General Electric Company	$141	$147	$125
Weighted-average shares outstanding (in thousands):			
Basic	75,498	75,333	75,275
Diluted	75,647	75,350	75,291
Earnings per share—basic and diluted	$1.87	$1.95	$1.66
Dividends declared per common share	$1.075	$1.055	$1.035

See accompanying notes to consolidated financial statements.

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PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions)

	Years Ended December 31,		
	2012	2011	2010
Net income	$140	$147	$121
Other comprehensive income (loss)—Change in compensation retirement benefits liability and amortization, net of taxes of $1 in 2011 and 2010	—	(1)	1
Comprehensive income	140	146	122
Less: comprehensive loss attributable to the noncontrolling interests	(1)	—	(4)
Comprehensive income attributable to Portland General Electric Company	$141	$146	$126

See accompanying notes to consolidated financial statements.

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

	As of December 31,	
	2012	2011
ASSETS		
Current assets:		
Cash and cash equivalents	$12	$6
Accounts receivable, net	152	144
Unbilled revenues	97	101
Inventories, at average cost:		
Materials and supplies	38	37
Fuel	40	34
Margin deposits	46	80
Regulatory assets—current	144	216
Other current assets	93	98
Total current assets	622	716
Electric utility plant:		
Production	2,899	2,854
Transmission	412	393
Distribution	2,816	2,704
General	327	314
Intangible	357	331
Construction work in progress	140	120
Total electric utility plant	6,951	6,716
Accumulated depreciation and amortization	(2,559)	(2,431)
Electric utility plant, net	4,392	4,285
Regulatory assets—noncurrent	524	594
Nuclear decommissioning trust	38	37
Non-qualified benefit plan trust	32	36
Other noncurrent assets	62	65
Total assets	$5,670	$5,733

See accompanying notes to consolidated financial statements.

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

	As of December 31, 2012	2011
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$98	$111
Liabilities from price risk management activities—current	127	216
Short-term debt	17	30
Current portion of long-term debt	100	100
Accrued expenses and other current liabilities	179	157
Total current liabilities	521	614
Long-term debt, net of current portion	1,536	1,635
Regulatory liabilities—noncurrent	765	720
Deferred income taxes	588	529
Unfunded status of pension and postretirement plans	247	195
Non-qualified benefit plan liabilities	102	101
Asset retirement obligations	94	87
Liabilities from price risk management activities—noncurrent	73	172
Other noncurrent liabilities	14	14
Total liabilities	3,940	4,067
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; 75,556,272 and 75,362,956 shares issued and outstanding as of December 31, 2012 and 2011, respectively	841	836
Accumulated other comprehensive loss	(6)	(6)
Retained earnings	893	833
Total Portland General Electric Company shareholders' equity	1,728	1,663
Noncontrolling interests' equity	2	3
Total equity	1,730	1,666
Total liabilities and equity	$5,670	$5,733

See accompanying notes to consolidated financial statements.

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

	Portland General Electric Company Shareholders' Equity				
	Common Stock				
	Shares	Amount	Accumulated Other Comprehensive Loss	Retained Earnings	Noncontrolling Interests' Equity
Balance as of December 31, 2009	75,210,580	$829	$(6)	$719	$1
Shares issued pursuant to equity-based plans	105,839	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
Shares issued pursuant to equity-based plans	46,537	1	—	—	—
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
Shares issued pursuant to equity-based plans	193,316	1	—	—	—
Stock-based compensation	—	4	—	—	—
Dividends declared	—	—	—		