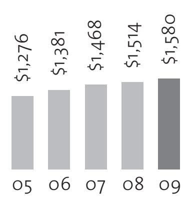
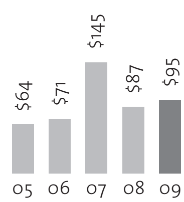
Portland General Electric Company
2009 Annual Report

Financial Highlights

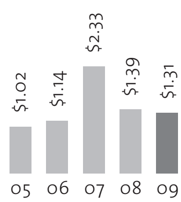
(dollars in millions, except per-share amounts)	2009	2008	2007
Operating revenues	$ 1,804	$ 1,745	$ 1,743
Net operating income	$ 208	$ 217	$ 269
Net income	$ 95	$ 87	$ 145
Return on equity (year-end)	6.2%	6.4%	11.0%
Total assets	$ 5,172	$ 4,889	$ 4,108
Dividends declared per common share	$ 1.010	$ 0.970	$ 0.930
Customers	815,739	810,197	803,788
Long-term debt, including current portion	$ 1,744	$ 1,306	$ 1,313
Long-term debt/capitalization	53.1%	45.6%	49.9%
Senior secured debt ratings (S&P/Moody's)	A-/A3	A/Baa1	A/Baa1
Commercial paper ratings (S&P/Moody's)	A-2/P-2	A-2/P-2	A-2/P-2
Employees	2,708	2,753	2,705



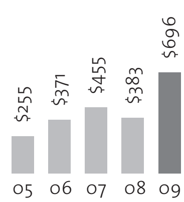
Retail energy sales



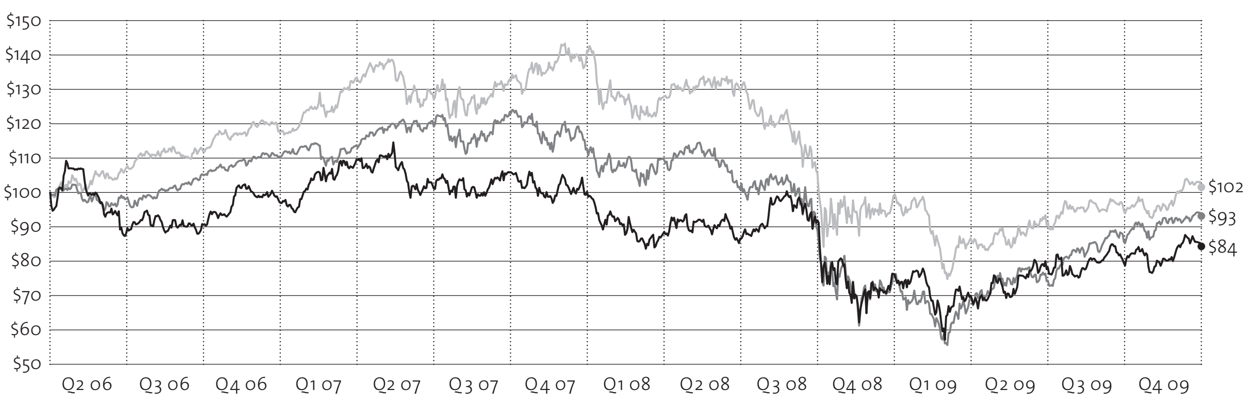
Net income



Earnings per share (diluted)



Capital expenditures



Stock Performance Graph[1]

Portland General Electric | S&P 500 | UTY Index

[1]*Assumes a $100 investment in PGE's common stock and each index on April 10, 2006, concurrent with the first day of regular-way trading of PGE common stock, and that all dividends were reinvested.*

About Portland General Electric

Portland General Electric Company (PGE), headquartered in Portland, Oregon, is a fully integrated electric utility serving approximately 816,000 residential, commercial and industrial customers in Oregon. PGE common stock is traded on the New York Stock Exchange under the symbol POR.

To Our Shareholders:

There are two ways to deal with turbulent times: wait for them to pass or use them as an opportunity to get stronger. At PGE we're taking action. Although 2009 was a challenging year for our customers, our company, and the entire utility industry, we have remained focused on building our core strengths and planning for Oregon's energy future.

We are making progress on executing our strategic initiatives—investments that create value for our customers and our shareholders alike. We are actively seeking new ways to gain operating efficiencies while continuing to meet our customers' expectations. And we are working to help key stakeholders understand our business and its challenges, which include sharing risks appropriately and earning a fair return for our shareholders.

We continue to make the right investments for PGE customers. Capital expenditures were $696 million in 2009, which included construction of Biglow Canyon Phases II and III, the smart meter project, and ongoing investments for the upgrade, replacement, and expansion of distribution, transmission, and generation infrastructure.

In 2009 PGE continued to see modest customer growth. Our residential sector, which accounts for 41 percent of total retail energy deliveries, remained stable, with weather-adjusted retail energy deliveries increasing 1.1 percent. Like most utilities across the nation, however, we saw a reduction in demand from commercial and industrial customers due to the economic recession, with a decline in deliveries of 2.7 and 8.4 percent, respectively. Fortunately, our diverse industrial customers—including high tech, solar, and manufacturing—have helped soften the impact. Net income for 2009 was $95 million, or $1.31 per diluted share, reflecting primarily the sustained effects of the economy, a decline in hydroelectric resources, higher incremental replacement power costs, and the Boardman plant deferred replacement power cost decision.

In the meantime we continue to take steps to run our business efficiently and cost-effectively. We are making capital investments, such as smart technologies and generation plant upgrades, to deliver lower costs for customers over the long term. And we have instituted a variety of temporary cost-saving actions to bridge the recession, such as salary freezes, voluntary furloughs, and reducing contract crews.

We have also maintained our investment-grade credit ratings. Last year we raised $750 million, including $170 million in equity and $580 million in long-term debt. Along with an increase in our revolving lines of credit, these transactions will support ongoing operations and provide liquidity to meet our capital expansion initiatives.

Our region is entering a crucial time when the expected future growth in demand for power is outpacing existing generation sources. At the same time, we need to balance a reliable power supply with environmental stewardship and reasonable costs. Our Integrated Resource Plan describes how we intend to reach that balance and meet the demand for power—all while moving toward achieving Oregon's Renewable Energy Standard goal of 25 percent by 2025. We're recommending the continuation of energy-efficiency programs; more renewable power; and new, efficient natural gas-fired generation. We're pursuing a potential transmission project, Cascade Crossing. And we're continuing discussions with regulators and stakeholders as we seek the best operating plan for the Boardman power plant, with the goal of providing a balance between system reliability, customer prices, and environmental effects.

To help meet our commitment of adding renewables to our system, construction on Phase II of our Biglow Canyon Wind Farm was completed in August 2009, on time and under budget. Phase II was fully included in prices effective January 1, 2010, with a total project cost of $321 million. Phase III, with an estimated cost of $428 million, is well under way, with completion slated for the third quarter of 2010.

We're also nearing completion of our smart meter project, with the installation of approximately 830,000 meters in homes and businesses by the close of 2010. This technology will help us reduce operating costs and more efficiently manage energy use, and it serves as a platform for smart grid development. Recently, the U.S. Department of Energy selected a Pacific Northwest consortium including PGE to conduct a demonstration project designed to test smart grid technology with customers.

We continue to explore other emerging technologies, including solar projects and electric vehicles. PGE was chosen to join eTec, Nissan, and the state of Oregon to test and analyze electric vehicle usage and charging-station infrastructure.

In 2010 we will continue to face challenges. We have filed a general rate case to reflect our projection of flat retail energy deliveries as well as increases in operations, maintenance, and capital-related expenses essential to operating our business and delivering the service and the reliability our customers expect. The general rate case is based on a 2011 test year with new prices expected to become effective January 1, 2011. Through a constructive regulatory process, we'll continue to ensure that key stakeholders understand our business, the value of future investments, and the importance of regulatory mechanisms that share risks and reduce volatility in earnings.

I continue to see intelligence, dedication, and innovation within PGE. Despite the many challenges of 2009, my co-workers found creative ways to do good work. Our overall customer satisfaction remains high, and we ranked highest in customer satisfaction with business electric service in the western United States.* We maintained excellent power quality and reliability even as we encountered a series of strong storms and a summer heat wave. And we continued to hit our targets for power plant operations. My co-workers also demonstrated their commitment to the community at a time when it was needed most; together we contributed more than $1.6 million to local organizations through our Employee Giving Campaign.

We are well positioned to move beyond the challenges of the current economic slowdown and successfully execute our strategic initiatives in the future. As a vertically integrated electric utility, we will invest wisely in our system to provide reliable, cost-effective power to our customers and growth opportunities for our shareholders. In short, we will make the most of every opportunity to emerge from the recession stronger, better, and worthy of your investment.

Sincerely,

Jim Piro

Jim Piro
President and Chief Executive Officer
March 15, 2010

*Source: J.D. Power and Associates 2009 Electric Utility Business Customer Satisfaction Study℠

Form 10-K

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

FORM 10-K

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

For the fiscal year ended December 31, 2009

OR

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

For the Transition period from ______ to ______

Commission File Number 1-5532-99

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

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

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

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

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

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ 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 ☒

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 ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Date File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 229.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☐ 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. ☐

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 ☒	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 ☒

As of June 30, 2009, the aggregate market value of voting common stock held by non-affiliates of the Registrant was $1,461,965,195. For purposes of this calculation, executive officers and directors are considered affiliates.

As of February 19, 2010, there were 75,210,580 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 2010 Annual Meeting of Shareholders to be held on May 13, 2010.

PORTLAND GENERAL ELECTRIC COMPANY
FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2009

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DEFINITIONS

The following abbreviations or acronyms used in the text and Notes to Consolidated Financial Statements are defined below:

Abbreviation or Acronym	Definition
AFDC	Allowance for funds used during construction
ASC	Accounting Standards Codification
BART	Best Available Retrofit Technology
Beaver	Beaver natural gas-fired generating plant
Biglow Canyon	Biglow Canyon Wind Farm
Boardman	Boardman coal-fired generating plant
BPA	Bonneville Power Administration
CERS	California Energy Resources Scheduling
Colstrip	Colstrip Units 3 and 4 coal-fired generating plant
Coyote Springs	Coyote Springs Unit 1 natural gas-fired generating plant
CUB	Citizens' Utility Board
Dth	Decatherm = 10 therms = 1,000 cubic feet of natural gas
DEQ	Oregon Department of Environmental Quality
EFSC	Energy Facility Siting Council
EITF	Emerging Issues Task Force of the Financial Accounting Standards Board
EPA	U.S. Environmental Protection Agency
ESA	Endangered Species Act
ESS	Electricity Service Supplier
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
IRP	Integrated Resource Plan
ISFSI	Independent Spent Fuel Storage Installation
kV	Kilovolt = one thousand volts of electricity
kW	Kilowatt = one thousand watts of electricity
kWh	Kilowatt hour
Moody's	Moody's Investors Service
MW	Megawatts
MWa	Average megawatts
MWh	Megawatt hours
NERC	North American Electric Reliability Corporation
NRC	Nuclear Regulatory Commission
NVPC	Net Variable Power Costs
OATT	Open Access Transmission Tariff
OEQC	Oregon Environmental Quality Commission
OPUC	Public Utility Commission of Oregon
PCAM	Power Cost Adjustment Mechanism
Port Westward	Port Westward natural gas-fired generating plant
REP	Residential Exchange Program
RES	Renewable Energy Standard
S&P	Standard & Poor's Ratings Services
SB 408	Oregon Senate Bill 408
SEC	U.S. Securities and Exchange Commission
SIP	Oregon Regional Haze State Implementation Plan
Trojan	Trojan Nuclear Plant
URP	Utility Reform Project
USDOE	U.S. Department of Energy
VIE	Variable Interest Entity
WECC	Western Electricity Coordinating Council

PART I

ITEM 1. BUSINESS.

General

Portland General Electric Company (PGE or the Company) is a vertically integrated electric utility engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the state of Oregon. PGE operates as a cost-based, regulated electric utility, with revenue requirements and customer prices determined based upon the forecast cost to serve retail customers, including an opportunity to earn a reasonable rate of return. PGE meets approximately 50% of its energy requirement with company-owned generation and purchases power in the wholesale market to meet its remaining requirement. The Company also participates in the wholesale market by purchasing and selling electricity and natural gas in order to manage its net variable power costs (NVPC). PGE operates as a single segment, with revenues and costs related to its business activities maintained and analyzed on a total electric operations basis.

PGE was incorporated in 1930 and is publicly-owned, with its common stock listed on the New York Stock Exchange under the ticker symbol "POR." The Company was a wholly-owned subsidiary of Enron Corp. (Enron) for the period from July 1, 1997 through April 3, 2006.

In 1997, Portland General Corporation, the former parent of PGE, merged with Enron, with Enron continuing in existence as the surviving corporation and PGE operating as a wholly-owned subsidiary of Enron. In December 2001, Enron, along with certain of its subsidiaries (collectively "Debtors"), filed for bankruptcy under Chapter 11 of the federal Bankruptcy Code. PGE was not included in the filing. On April 3, 2006, in accordance with Enron's Chapter 11 plan, PGE's 42.8 million shares of common stock held by Enron were canceled, PGE issued 62.5 million of new shares of common stock, with 27 million shares issued to the Debtors' creditors holding allowed claims and 35.5 million shares issued to a Disputed Claims Reserve, and PGE and Enron entered into a separation agreement. Following issuance of the new PGE common stock, PGE ceased to be a subsidiary of Enron. On June 18, 2007, the Disputed Claims Reserve sold substantially all of its remaining holdings of PGE stock in a public offering.

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 2009 its service area population was 1.7 million, comprising about 43% of the state's population. The Company added 5,542 customers during 2009 and served a total of 815,739 retail customers as of December 31, 2009.

As of December 31, 2009, PGE had 2,708 employees, with 890 employees covered under agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers (Local 125). Such agreements cover 856 and 34 employees and expire on February 28, 2012 and August 1, 2011, respectively.

Available Information

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

Regulation and Rates

As a public utility, PGE is subject to federal and state regulation, which can have a significant impact on the business and operations of the Company as well as prices charged for electric service. 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) and the Nuclear Regulatory Commission (NRC).

FERC Regulation

The Company is a "licensee" and a "public utility," as defined in the Federal Power Act, and is subject to regulation by the FERC in matters related to wholesale energy activities, transmission services, reliability standards, natural gas pipelines, hydroelectric project licensing, accounting policies and practices, short-term debt issuances, and certain other matters. The Energy Policy Act of 2005 (EPAct 2005) granted the FERC statutory authority to implement mandatory reliability standards and also authorized monetary penalties for non-compliance with such standards and other FERC regulations. EPAct 2005 also provides for enhanced oversight of power and transmission markets, including protection against market manipulation.

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 at the FERC in June 2010.

Transmission—Terms and conditions pursuant to which PGE offers transmission service are contained in the Company's 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. As of December 31, 2009, PGE owned approximately 1,200 miles of transmission lines. For additional information, see the Transmission and Distribution section in this Item 1. and in Item 2.—"Properties."

Reliability Standards—Pursuant to EPAct 2005, the FERC has adopted mandatory reliability standards for owners, users and operators of the bulk electric 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.

Pipeline—The Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978 provide FERC authority in matters related to 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% ownership interest in the 17-mile interstate pipeline that provides natural gas to its Port Westward and Beaver plants.

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 numerous natural resource issues and environmental conditions. PGE holds new FERC licenses for the Company's projects on the Deschutes and Willamette Rivers and is currently in the process of relicensing its four hydroelectric projects on the Clackamas River. For additional information, see the Environmental Matters section in this Item 1.

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

Short-term Debt—Pursuant to applicable provisions of the Federal Power Act and FERC regulations, regulated public utilities are required to obtain FERC approval to issue certain securities. Pursuant to an order issued by the FERC on January 29, 2010, the Company is authorized to issue up to $750 million of short-term debt through February 6, 2012.

NRC Regulation

The NRC regulates the licensing and decommissioning of nuclear power plants, including PGE's Trojan Nuclear Plant, 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 facility is available. Radiological decommissioning of the plant site was completed in 2004 under an NRC-approved plan, with the plant's operating license terminated in 2005. Spent fuel storage activities will continue to be subject to NRC regulation until all nuclear fuel is removed from the site and radiological decommissioning of the storage facility is completed.

State of Oregon Regulation

PGE is subject to the jurisdiction of the Public Utility Commission of Oregon (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 stock and long-term debt, prescribes accounting policies and practices, and reviews applications to sell utility assets, engage in transactions with affiliated companies, and acquire substantial influence over a public utility. The OPUC also reviews the Company's generation and transmission resource acquisition plans, pursuant to an integrated resource planning process.

Following the announced resignation of Lee Beyer as Chairman of the OPUC, current commissioner Ray Baum has been appointed to serve as Chairman. In addition, John Savage, who has served on the OPUC since 2003, has been reappointed to another four-year term and Susan Ackerman has been appointed to serve the remaining two years of Chairman Beyer's term. Such appointments are effective on March 1, 2010.

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. Members of the EFSC are appointed by the state's governor, with staff support provided by the Oregon Department of Energy.

Ratemaking—Under Oregon law, the OPUC is required to ensure that the prices and terms of service are fair, non-discriminatory, and provide regulated companies an opportunity to earn a fair return on their investments. Customer prices are determined through formal ratemaking proceedings that generally include testimony by participating parties, data requests, public hearings, and the issuance of a final order. Participants in such proceedings, which are conducted under established procedural schedules, include PGE, OPUC staff, and intervenors.

- *General Rate Cases*. PGE periodically evaluates the need to change its retail electric price structure to sufficiently cover its operating costs and provide a reasonable rate of return. Such changes are requested pursuant to a comprehensive general rate case process that includes a forecasted test year, a proposed debt-to-equity capital structure, return on equity, and overall rate of return. Based upon such factors, revenue requirements and retail customer price changes are proposed. For additional information, see the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

- *Power Costs*. In addition to price changes resulting from the general rate case process, the OPUC has approved the following mechanisms by which PGE can adjust retail customer prices to cover the Company's NVPC, which consists of direct and indirect costs of power and fuel less revenues from wholesale electricity sales:
    - Annual Power Cost Update Tariff. Under this tariff, customer prices are adjusted annually to reflect the latest forecast of NVPC. Such forecasts assume average regional hydro conditions (based on a 70-year regulation study covering the period 1928 - 1998) utilized in the Company's most recent general rate case, with no adjustments for updated hydro projections. An initial forecast, submitted to the OPUC by April 1 each year, is updated during the year and finalized in November. Based upon the final forecast, new prices, as approved by the OPUC, become effective at the beginning of the next calendar year; and
    - Power Cost Adjustment Mechanism (PCAM). Customer prices can also be adjusted to reflect a portion of the difference between each year's forecasted NVPC included in prices and actual NVPC for the year. Under the PCAM, PGE is subject to a portion of the business risk or benefit associated with the difference between actual NVPC and that included in base prices. The PCAM utilizes an asymmetrical deadband within which PGE absorbs cost variances, with a 90/10 sharing of such variances between customers and the Company outside of the deadband. Annual results of the PCAM are subject to application of a regulated earnings test, with final determination of any customer refund or collection made by the OPUC through a public filing and review. For additional information, see the Results of Operations section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."
- *Renewable Energy*. The 2007 Oregon Renewable Energy Act (the Act) established a Renewable Energy Standard (RES) which requires that PGE serve at least 5% of its retail load within the state from renewable resources from 2011 through 2014, 15% for 2015 through 2019, 20% for 2020 through 2024, and 25% in 2025 and subsequent years. PGE anticipates that it will meet the 2011 requirement of the Act with existing or currently planned renewable resources. Further, the Company expects that, with additional resources included in its currently proposed integrated resource plan, it will meet the 2015 requirement. It is anticipated that subsequent years' requirements will be met by the acquisition of additional renewable resources, as determined pursuant to the Company's integrated resource planning process. For additional information, see the Power Supply section in this Item 1.

  The Act also provides for the recovery in customer rates of all prudently incurred costs required to comply with the RES. 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 rates. Under the RAC, PGE submits a filing on April 1 of each year for new renewable resources being placed in service in the current year, with rates to become effective January 1st of the following year. In addition, the RAC provides for the deferral of eligible costs incurred prior to January 1st of the following year.

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

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

Utility Rate Treatment of Income Taxes—In 2005, Oregon adopted Senate Bill 408 (SB 408). The law attempts to more closely match income tax amounts forecasted to be collected in revenues with the amount of income taxes paid to governmental entities by investor-owned electric and natural gas utilities or their consolidated group. The law requires that utilities file a report with the OPUC each year regarding the amount of taxes paid by the utility (with certain adjustments), as well as the amount of taxes authorized to be collected in rates, as defined by the statute. This report is filed by October 15th of the year following the reporting year. If the OPUC determines that the difference between the two amounts is greater than $100,000, the utility is required to adjust future rates, with a regulatory asset or liability recorded for the total amount (including accrued interest) to be collected from, or refunded to, retail customers.

Application of the provisions of SB 408 can, in certain situations, result in unusual outcomes, commonly termed the "double whammy" effect. As the provisions of the law apply to PGE, if the Company records higher actual operating income than forecast in its latest general rate case, customers are surcharged for the resulting increase in income taxes, further increasing earnings. Conversely, if the Company records lower actual operating income than forecast in its latest rate case, customers receive refunds for the resulting decrease in income taxes, further decreasing earnings.

For additional information, see Note 6, Regulatory Assets and Liabilities, in the Notes to Consolidated Financial Statements.

Retail Customer Choice Program—This program allows PGE's commercial and industrial customers direct access to other suppliers of electricity (Electricity Service Suppliers, or ESSs). While such customers can purchase their electricity from other suppliers, PGE continues to deliver the energy. The program provides for "transition adjustments" that reflect the above- or below-market cost of energy resources owned or purchased by the utility, with such adjustments designed to ensure that such costs or benefits do not unfairly shift to the utility's remaining energy customers. The retail customer choice program is intended to have no material effect on the financial condition or results of operations of the Company.

In addition to opting-out of cost-of-service for terms of one year or less to be served by an ESS, PGE also offers an option by which certain large non-residential customers may elect to be removed from cost-of-service pricing for a fixed three-year or a minimum five-year term. In 2009, ESSs supplied PGE customers with a total average load of approximately 221 MWa, representing 17% of PGE's non-residential load and 10% of the Company's total retail load for the year. In early 2010, the four ESSs registered to transact business with PGE supply an average load of approximately 134 MWa, representing 10% of the Company's non-residential load and 6% of total retail load.

Daily and monthly market price options are also available to PGE's commercial and industrial customers. At the end of 2009, PGE served customers with a total load of 12 MWa under such options, representing 1% of nonresidential load and less than 1% of total retail load. PGE served the remaining 82% of nonresidential load under cost-of-service or other portfolio options.

Residential and small commercial customers can purchase electricity from PGE from a portfolio of rate options that include a basic cost-of-service rate, a time-of-use rate, and renewable resource rates. As of December 31, 2009, approximately 82,000 customers were enrolled in renewable energy options, with 2,130 enrolled in time-of-use options. As of December 31, 2008, approximately 71,000 customers were enrolled in renewable energy options, with 2,058 enrolled in time-of-use options.

Energy Efficiency Funding—Oregon's electricity restructuring law also 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. In 2009 and 2008, approximately $48 million and $47 million, respectively, were billed to customers for this charge.

PGE also remits to the ETO amounts collected under an Energy Efficiency Adjustment tariff to fund additional energy efficiency measures. The tariff, which became effective on June 1, 2008, included an approximate 1% charge for eligible customers, providing about $14 million annually for measures that enable customers to reduce their energy use. Effective January 1, 2010, the charge was increased to approximately 1.5%, which is expected to provide about $21 million annually.

Decoupling—Pursuant to OPUC authorization in PGE's most recent general rate case (2009 General Rate Case), the Company is deferring, for later ratemaking treatment, amounts associated with a new decoupling mechanism. The mechanism is intended to provide for recovery of reduced revenues resulting from a reduction in electricity sales attributable to energy efficiency and conservation efforts by residential and certain commercial customers. It also provides for customer refunds if weather adjusted use per customer exceeds that approved in the rate case. For 2009, PGE accrued a refund to customers of $6.8 million, as weather adjusted use per customer for the year exceeded that approved in the rate case.

Regulatory Accounting

As a regulated public utility, PGE is subject to generally accepted accounting principles for regulated operations to reflect the effects of rate regulation in its financial statements. These principles provide for the deferral as regulatory assets of certain actual or anticipated costs that would otherwise be charged to expense, based on expected recovery from customers in future rates. 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 allowed for recovery or refund in future rates, 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.

Customers and Revenues

PGE conducts retail electric operations exclusively in Oregon within a state-approved service area. Competitors within the Company's service territory include the local natural gas company, which competes in the residential and commercial space heating, water heating, and appliance markets, and fuel oil suppliers, which compete primarily for residential space heating customers. In addition, commercial and industrial customers may choose to purchase their energy requirements from ESSs. For additional information on customer choice, see *Retail Customer Choice Program* within the Regulation and Rates section in this Item 1.

The following table summarizes PGE's revenues for the years presented, with dollars in millions, except as indicated. Certain averages for retail customers who purchase their energy requirements from the Company are also reflected below:

	Years Ended December 31,					
	2009		2008		2007	
	Amount	%	Amount	%	Amount	%
Retail:						
Residential	$ 794	44%	$ 758	44%	$ 716	41%
Commercial	619	35	598	34	593	34
Industrial	167	9	158	9	159	9
Other	77	4	(6)	(1)	48	3
Total retail revenues	1,657	92	1,508	86	1,516	87
Wholesale revenues	112	6	195	11	201	12
Other operating revenues	35	2	42	3	26	1
Revenues, net	$ 1,804	100%	$ 1,745	100%	$ 1,743	100%
Average usage per customer (in kilowatt hours):						
Residential	11,059		11,080		10,953	
Commercial	70,853		72,486		74,303	
Industrial	9,343,838		11,392,166		11,449,959	
Average revenue per customer (in dollars):						
Residential	$ 1,111		$ 1,066		$ 1,020	
Commercial	6,127		5,996		6,050	
Industrial	660,839		730,994		730,791	
Average revenue per kilowatt hour (in cents):						
Residential	10.05¢		9.62¢		9.31¢	
Commercial	8.65		8.27		8.14	
Industrial	7.07		6.42		6.38	

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

Retail Revenues

Retail customers are categorized into residential, commercial, and industrial classes, with no single customer representing more than 1% of PGE's total retail revenues or 5% of total retail deliveries. Commercial and industrial customer classes are not dominated by any single industry. While the 20 largest commercial and industrial customers constituted 8% of total retail revenues in 2009, they represented nine different groups, including retail, high technology, paper manufacturing, metal fabrication, health services and governmental agencies. Additional information on these customer classes follows.

Residential customers include single family housing, multiple family housing (such as apartments, duplexes and townhomes), mobile homes, and small farms. Pricing of service to the residential class is based on the costs PGE incurs to provide electric service, unless the customer has selected time-of-use or renewable resource pricing. On average for the last three years, residential customers have comprised 88% of total customers, provided 49% of total retail revenues, and accounted for 40% of total retail energy deliveries.

Residential demand is sensitive to the effects of weather, with demand historically highest during the winter heating season although, due to the increased use of air conditioning in PGE's service territory, the summer peaks have increased in recent years. The state of the economy also affects demand from the Company's residential customers. Historical data has suggested that a 1% increase in Oregon's unemployment rate has resulted in an approximate 0.4% decrease in total demand from the Company's residential customers. During 2009, however, when the unemployment rate increased about 5%, total residential deliveries remained comparable to 2008.

Commercial customers consist of non-residential customers who accept delivery at voltages equivalent to that delivered to residential customers. This customer class includes most commercial businesses, as well as small industrial customers and public street and highway lighting, with pricing based on the amount of electricity used. On average for the last three years, commercial customers comprised 12% of total customers, provided 39% of total retail revenues, and accounted for 39% of total retail energy deliveries.

Demand from the Company's commercial customers is generally not affected significantly by weather; however, demand can be affected by total employment in the region. Typically, a 1% change in Oregon's total employment can lead to an approximate 0.6% change in demand from the Company's commercial customers. During 2009, as the Oregon economy lost about 5.1% of its payroll, the Company's commercial energy deliveries decreased 3.6% compared to 2008.

Industrial customers consist of non-residential customers who accept delivery at higher voltages than commercial customers, with pricing based on the amount of electricity used and applicable tariff rate. On average for the last three years, industrial customers have comprised less than 1% of total customers, provided 10% of total retail revenues, and accounted for 21% of total retail energy deliveries.

Demand from industrial customers is primarily affected by national and global economic conditions. Weather has little impact on this customer class. Typically, a 1% change in Oregon's total employment can lead to an approximate 0.2% change in demand from the Company's industrial customers. Although the Oregon economy lost about 5.1% of its payroll in 2009, total energy deliveries to industrial customers decreased 9.3% in 2009 compared to 2008.

Direct access customers consist of commercial and industrial customers who purchase their electricity from an ESS, with PGE delivering the electricity. The revenue earned in connection with the transmission and delivery of this electricity, net of transition adjustments, is included in Other retail revenues. PGE served an average of 262 direct access customer accounts in 2009, 417 in 2008, and 322 in 2007. The number of ESS customers, deliveries, and revenues are included among the figures discussed above for the Company's total commercial and industrial customers.

Residential Exchange Program (REP)—Under the REP, the Bonneville Power Administration (BPA) provides federal hydropower benefits to residential and small farm customers of certain investor-owned electric utilities. Under the program, PGE receives monthly payments from BPA and passes such payments along to eligible customers in the form of monthly billing credits. In May 2007, the BPA suspended payments under the program, which resulted in an approximate 14% average price increase to the Company's eligible customers. Benefits were partially restored on a temporary basis in April 2008, which reduced prices for residential and small farm customers by an average of 6.3%.

In September 2008, the BPA and PGE entered into an agreement that provides for monthly payments through the term of the agreement, which extends to September 2011. For the twelve month period ended September 30, 2009, PGE received payments totaling approximately $40 million. Payments for the twelve month periods ending September 30, 2010 and 2011 are expected to be approximately $48 million and $49 million, respectively, with benefits to be credited to eligible customers. The Company will continue to pursue ongoing benefits for its customers under the REP.

Wholesale Revenues

PGE participates in the wholesale marketplace in order to balance its supply of power to meet the needs of its retail customers, manage risk, and administer its current long-term wholesale contracts. The Company's wholesale market participation includes purchases and sales of power resulting from economic dispatch decisions for its own generation, which allows PGE to secure reasonably priced power for its customers, and purchases and sales of natural gas. 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, water conditions, and seasonal demand.

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

Other Operating Revenues

Other includes sales of natural gas or oil in excess of generating plant requirements and revenues from transmission services and excess transmission capacity resales, pole contact rentals, and certain other electric services to customers.

Seasonality

Seasonal demand for electricity by PGE's residential customers is affected by weather conditions, as discussed above. Heating and cooling degree-days are common measures used to analyze the effect of weather on the demand for electricity. Heating and cooling degree-days, which measure how much the average daily temperature varies from 65 degrees, indicate the extent to which customers are likely to use electricity for heating or air conditioning. The higher the numbers of degree-days, the greater the expected demand for heating or cooling.

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

	Heating Degree-Days	Cooling Degree-Days
2009	4,224	627
2008	4,582	474
2007	4,374	400
15-year average for 2009	4,169	467

The table indicates that during 2009, demand for heating was greater than the 15-year average, but less than what it was in 2008. Demand for electricity for air conditioning was also greater in 2009 than it was in 2008, which was a near average cooling-degree year.

The Company tracks both base load growth and peak capacity for purposes of long-term load forecasting and resource planning. PGE's all-time high net system load peak of 4,073 MW occurred in December 1998. The Company's all-time "summer peak" of 3,949 MW, driven by unusually warm weather, occurred in July 2009 and exceeded the December 2009 winter peak of 3,851 MW. PGE's average load was 2,658 MWa for the winter and 2,267 MWa for the summer in 2009, compared to 2,691 MWa for the winter and 2,324 MWa for the summer in 2008.

Power Supply

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

PGE's base generating resources consist of five thermal plants, seven hydroelectric plants, and wind farms located at Biglow Canyon. The volume of electricity the Company generates is dependent upon, among other factors, the capacity and availability of its generating resources. Capacity of a given plant 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. Availability represents the percentage of the year the plant was available for operations, which reflects the impact of planned, forced and maintenance outages. For a complete listing of these facilities, see Item 2.—"Properties."

The Company also promotes the expansion of renewable energy resources, as well as energy efficiency measures, to meet such needs and enhance customers' ability to manage their energy use more efficiently.

The following table summarizes PGE's average resource capacity (in MW) for the last three years:

	As of December 31,					
	2009		2008		2007	
	Capacity	%	Capacity	%	Capacity	%
Generation:						
Thermal:						
Natural gas	1,175	26%	1,175	26%	1,145	25%
Coal	670	15	670	15	676	14
Total thermal	1,845	41	1,845	41	1,821	39
Hydro	489	11	489	11	503	11
Wind	275	6	125	3	125	3
Total generation	2,609	58	2,459	55	2,449	53
Purchased power:						
Long-term contracts:						
Capacity/exchange	630	14	644	15	644	14
Mid-Columbia hydro	548	12	545	12	566	13
Confederated Tribes hydro	150	3	150	3	150	3
Wind	35	1	35	1	35	1
Other	243	5	243	5	243	5
Total long-term contracts	1,606	35	1,617	36	1,638	36
Short-term contracts	315	7	379	9	485	11
Total purchased power	1,921	42	1,996	45	2,123	47
Total average resource capacity	4,530	100%	4,455	100%	4,572	100%

For information regarding actual generating output and purchases for the years ended December 31, 2009, 2008 and 2007, see the Results of Operations section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Generation

That portion of PGE's energy 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, and the market price of electricity.

Thermal PGE has a 65% ownership interest in Boardman, which it operates, and a 20% ownership interest in Colstrip Units 3 and 4. These two coal-fired generating facilities provided approximately 20% of the Company's total retail load requirement in 2009 and 27% in 2008. The Company's three natural gas-fired generating facilities, Port Westward, Beaver, and Coyote Springs, provided approximately 24% of its total retail load requirement in 2009 and 2008. These thermal plants, which have a combined capacity of approximately 1,175 MW, continue to provide reliable power for customers. Plant availability, excluding Colstrip, was approximately 84% in 2009 and 89% in 2008, with Colstrip availability approximately 68% in 2009 compared to 97% in 2008.

Hydro The Company's FERC-licensed hydroelectric projects consist of two plants on the Deschutes River near Madras, Oregon, four plants on the Clackamas River and one on the Willamette River. These plants, which have a combined capacity of 489 MW, provided approximately 10% of the Company's total retail load requirement in 2009 and 2008, with availability of 99% in both years. 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 two-thirds 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 undivided 16.66% interest in Pelton/Round Butte at its discretion no sooner than January 2, 2019 and no later than July 1, 2021. The Tribes have a second option to purchase an undivided 0.02% interest in Pelton/Round Butte at its discretion no sooner than December 31, 2036. 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 project. Biglow Canyon Phase I, comprised of 76 wind turbines with a total installed capacity of approximately 125 MW, was completed and placed in service in December 2007. Phase II is comprised of 65 wind turbines with a total installed capacity of approximately 150 MW and was completed and placed in service in August 2009. In 2009, wind resources provided approximately 3% of the Company's total retail load requirement and 2% in 2008, with availability at approximately 97% in 2009 and 92% in 2008. Completion of Phase III is expected by the end of the third quarter of 2010, with a total of 76 wind turbines and an installed capacity of approximately 175 MW.

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, 2009, there were 23 projects that together can provide approximately 48 MW of diesel-fired capacity at peak times.

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, option, and futures contracts to manage its exposure to volatility in natural gas prices.

Coal

Boardman—PGE has fixed-price purchase agreements that provide coal for Boardman through 2011. 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.

Colstrip—Coal for Colstrip Units 3 and 4 is obtained from an adjacent mine under a contract that extends to 2019.

Natural Gas

Port Westward and Beaver—Firm gas supplies for Port Westward and Beaver are purchased up to 72 months in advance, based on anticipated operation of the plants. PGE owns 79% 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 on an interruptible basis to the extent not utilized by the Company. PGE has access to 103,305 Dth/day of firm gas transportation capacity to serve the two plants and has also received authorization from the FERC to transport natural gas for others under a Part 284 blanket transportation certificate.

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. PGE believes that sufficient market supplies of gas are available to meet anticipated operations of Port Westward and Beaver.

The Beaver generating plant has the capability to operate at full capacity on No. 2 diesel fuel oil when it is economic or if the plant's natural gas supply is interrupted. PGE had an approximate 5-day supply of oil at the plant site as of December 31, 2009.

Coyote Springs—The Coyote Springs generating station utilizes 41,000 Dth/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, based on anticipated operation of the plant. Although Coyote Springs was designed to also operate on 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 energy requirements. The Company utilizes short- and long-term wholesale power purchase contracts to provide the most favorable economic mix on a variable cost basis. Such contracts have terms ranging from one month to 30 years and expire at varying dates through 2035.

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 attempts to mitigate volatility in the average cost of purchased power and fuel from year to year.

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—These five contracts provide PGE with firm capacity to help meet the Company's peak loads. The contracts range from 30 MW to 300 MW and expire at various dates from February 2010 through December 2016. They include seasonal exchange contracts with other western utilities that help meet both winter- and summer-peaking requirements.

Mid-Columbia hydro—PGE has long-term power purchase contracts with certain public utility districts in the state of Washington for a portion of the output of four hydroelectric projects on the mid-Columbia River. The projects currently provide a total of 548 MW of firm capacity, with actual energy received dependent upon river flows. Under terms of its contract with one of the districts, the Company's share of the combined output of two of the projects is expected to decline from the current 233 MW to an estimated 158 MW in 2010 as the energy requirements of the district increase.

Confederated Tribes—PGE has a long-term agreement that requires the Company to purchase, at market prices, the Tribes' interest in the output of the Pelton/Round Butte hydroelectric project.

Wind—The Company has two long-term contracts, which extend to 2028 and 2035, that provide for the purchase of renewable wind-generated electricity.

Other—These consist of long-term contracts to purchase power from various counterparties, including other Pacific Northwest utilities, over terms extending up to 2018.

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 one hour 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.

Solar—PGE has invested in two photovoltaic solar power projects through separate limited liability companies. The first project, with an installed capacity of approximately 104 kW, is located on property owned by the Oregon Department of Transportation (ODOT) and was placed in service in December 2008. PGE purchases any excess energy generated from this facility pursuant to a net metering arrangement with ODOT. The second project, with a total installed capacity of approximately 1,095 kW, is located on the rooftops of three distribution warehouses in Portland and was placed in service between December 2008 and January 2009. PGE purchases 100% of the energy generated from this facility. PGE serves as managing member for both limited liability companies, in which it has an initial interest of less than 1%, and operates both facilities under an agreement with the investor member.

Future Energy Resource Strategy

Periodically, PGE is required to file with the OPUC an Integrated Resource Plan (IRP), which guides the utility on how it will meet future customer demand and describes the Company's energy supply strategy for the coming years, 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.

On November 5, 2009, PGE filed a new IRP that includes a four-year strategy for the acquisition of new resources and a 20-year strategy that outlines long-term expectations for resource needs and portfolio performance. PGE projects that it will need 873 MWa of new resources by 2015, increasing to 1,396 MWa by 2020, to meet expected customer demand. Such projected energy gaps are driven primarily by continued load growth and the expiration of certain long-term power supply contracts and will be updated periodically for any changes in underlying assumptions.

To meet the projected energy gap, the IRP includes energy efficiency measures, new renewable resources, new transmission capability, new generating plants, and improvements to existing generating plants as follows:

- Acquisition of 214 MWa of energy efficiency through continuation of Energy Trust of Oregon programs, with funding to be provided from the existing public purpose charge and through enabling legislation included in Oregon's Renewable Energy Standard;

- An additional 122 MWa of wind or other renewable resources necessary to meet requirements of Oregon's Renewable Energy Standard by 2015;
- Transmission capacity additions to interconnect new and existing energy resources in eastern Oregon to PGE's services territory. For additional information, see the Transmission and Distribution section in this Item 1;
- New natural gas generation facilities to help meet additional base load requirements estimated at 300 to 500 MW;
- New natural gas generation facilities to help meet peak capacity requirements estimated at 200 MW; and
- Future plans for Boardman, the Company's coal-fired plant.

As part of this IRP, PGE plans to install emissions controls at its Boardman plant to reduce the plant's haze-causing emissions, including airborne mercury. After filing the IRP, PGE determined that it will consider an alternative operating plan for Boardman, under which the plant will either discontinue the use of pulverized coal as a fuel source, or cease operations in 2020 and be replaced with a new base load resource. As a result, the Company requested that the OPUC delay consideration of the IRP to allow for additional analysis. The Company intends to file an addendum to its IRP during March 2010, following the presentation of the Company's proposal to intervenors in this matter. The Company has also agreed to submit a final proposed IRP schedule following discussions with intervenors. Pursuant to the final schedule, the OPUC will review PGE's IRP and accept public comments before issuing an order concerning acknowledgment of the plan.

For additional information about emissions controls for the Boardman plant, see the Capital Requirements section in Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operation."

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 2009, PGE delivered approximately 22 million MWh in its balancing authority area through approximately 1,200 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's transmission system, together with contractual rights to other transmission systems, enables the Company to integrate and access generation resources to meet its customers' load 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 Interior or lease by Native American tribes.

PGE's wholesale transmission activities are regulated by the FERC pursuant to the Company's OATT, which provides for market-based rates. In accordance with its OATT, PGE offers several transmission services to wholesale customers:

- Network integration transmission service, a guaranteed service that integrates generating resources to serve retail loads;
- Long- and short-term firm point-to-point transmission service, a guaranteed 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 the FERC's Standards of Conduct, PGE's transmission business is managed and operated independently from its power marketing business.

PGE's current IRP filing includes a 200-mile, 500 kV transmission project (the Cascade Crossing Transmission Project) that would help meet growing demand by interconnecting new and existing energy resources in eastern Oregon to the Company's service territory. PGE is coordinating with other utilities and the WECC in planning the project and is currently exploring potential routes.

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 are provided 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, see the Transmission and Distribution section of Item 2.—"Properties."

Environmental Matters

PGE's operations are subject to a wide range of environmental protection laws, including those related to air and water quality, climate change, noise, endangered species, and waste disposal. Various state and federal agencies have jurisdiction over environmental matters that include the siting and operation of generation, transmission, and substation facilities and the accumulation, cleanup, and disposal of toxic and hazardous substances. In addition, certain of the Company's hydroelectric projects and transmission system facilities are located on property under the jurisdiction of federal, tribal, and/or state agencies which have authority in environmental protection matters.

Air Quality Standards

Clean Air Act—PGE's operations, primarily its thermal generating plants, are subject to the federal Clean Air Act (CAA). Primary pollutants addressed by the CAA that affect PGE are sulfur dioxide (SO_2), nitrogen oxides, carbon monoxide, and particulate matter. State governments, including Oregon, also monitor and administer certain portions of the CAA and must set standards that are at least equal to federal standards.

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

Mercury Rules—The states in which PGE facilities are located have adopted the following regulations concerning mercury emissions that are likely to have an impact on the Company's Boardman and Colstrip plants:

- The Montana Board of Environmental Review adopted final rules on mercury emissions from coal-fired generating plants in Montana, including Colstrip, which required compliance with mercury emission limits by January 1, 2010. With the installation of additional mercury control systems now completed, the Colstrip plants are expected to meet these requirements.
- The Oregon Environmental Quality Commission (OEQC) has adopted final rules on mercury emissions from the state's coal-fired generating plants, including Boardman. Such rules require compliance with stated mercury limits by July 1, 2012, although this deadline can be extended by two years under certain circumstances. PGE has submitted its mercury control plan to the Oregon Department of Environmental Quality (DEQ) outlining measures it will take to comply with the state's mercury emissions rules.

Regional Haze Rules—In accordance with federal regional haze rules aimed at visibility impairment in certain federally protected areas, the DEQ conducted an assessment of emission sources that has indicated that Boardman contributes to visibility impairment in several federally protected areas and would be subject to a Regional Haze Best Available Retrofit Technology Determination, as required under the CAA.

In June 2009, the OEQC adopted a rule that would require the installation of emissions controls at Boardman in phases, with estimated completion by 2017. The OEQC rule has been submitted to the Environmental Protection Agency (EPA) for approval as part of the Oregon Regional Haze State Implementation Plan (SIP). The Company expects the EPA to issue a decision on the SIP in 2010.

Based on requirements outlined in the OEQC's rule and current market conditions for air quality equipment, PGE estimates that the approximate cost of the controls required by the rule would be between $520 million and $560 million (100% of total costs, excluding Allowance for Funds Used During Construction, or AFDC). PGE has no commitments in place at this time and cautions that the cost estimates are preliminary and subject to change. PGE will seek recovery of such costs through the ratemaking process.

In PGE's November 2009 IRP filing, given the options provided by the OEQC of either ceasing operation of Boardman or installing controls and continuing operations, the Company recommended the continued operation of Boardman through 2040 with the addition of the controls required by the OEQC.

Continuing discussions with IRP stakeholders indicate support for the analysis of an alternative strategy regarding Boardman. The Company is committed to seeking the best plan for providing reliable and reasonably priced electricity for customers. Accordingly, PGE has informed the OPUC that the Company intends to pursue an alternative operating plan for Boardman that would allow the operation of Boardman through 2020 with only the mercury controls and low nitrogen oxide burners. PGE has requested, and the OPUC has granted, suspension of the IRP proceedings to allow the Company sufficient opportunity to prepare an alternative Boardman operating plan for inclusion in the IRP. For additional information, see *Boardman emissions controls* in the Capital Requirements section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

The alternative plan, using a 2020 timeline, would allow the Company time to plan and implement an appropriate replacement strategy for Boardman if the plant were to close. Current options under consideration include construction of a new plant or the use of an alternative fuel to operate Boardman.

PGE would seek to recover in future rates its remaining investment in Boardman (approximately $125 million as of December 31, 2009) plus the cost of the mercury controls, low nitrogen oxide burners and decommissioning and other costs related to the plant's closure, as well as the construction or acquisition costs of replacement generating capacity.

If agreement with all regulatory bodies cannot be reached to allow for an alternative operating plan for Boardman, PGE will continue to seek approval for installation of all required emissions controls and continued operation of the plant.

Climate Change—Greenhouse gas (GHG) emissions and their potential impacts on climate change have received increased public attention, with state, regional, and federal legislative efforts initiated to establish mandatory controls.

Recent or pending environmental measures include the following:

- In 2007, the State of Oregon adopted a goal to reduce GHG emissions to 10% below 1990 levels by 2020. The non-binding goal does not mandate reductions by any specific entity nor does it include penalties for failure to meet the goal; however, it serves as a policy guideline for the state.
- In June 2009, the U.S. House of Representatives approved the American Clean Energy and Security Act of 2009, which seeks to establish a cap and trade system for GHG emissions. Debate in the U.S. Senate on similar legislation is continuing.
- The EPA has made it mandatory, effective January 1, 2010, for certain companies, including PGE, to measure and report GHG emissions. Reported data will be used to establish a baseline for measuring progress toward any future emissions reduction targets in the United States.
- The Oregon Emissions Performance Standard, passed by the Oregon legislature in 2009, prohibits utilities from entering longer than five-year commitments with energy facilities, or contracts for energy, for which the associated emissions exceed prescribed levels. This standard may have an impact on the Company's ability to contract for, or prices it pays to acquire, energy to meet future customer needs. Other states in the western electricity grid, including Washington and California, have also enacted similar legislation.

Any laws that impose mandatory reductions in GHG emissions could have a material impact on PGE, as the Company utilizes fossil fuels in its own power generation and other companies use such fuels to generate power that PGE purchases in the wholesale market. PGE's Beaver, Coyote Springs, and Port Westward natural gas-fired facilities, and the Company's interest in Boardman and Colstrip coal-fired facilities, provide approximately 70% of the Company's net generating capacity.

The ultimate impact that the above regulatory requirements and emissions controls will have on future operations, costs, or generating capacity of PGE's thermal generating facilities is not yet determinable and is being evaluated as part of the integrated resource planning process.

Water Quality and Endangered Species Protection

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

Fish Protection—Populations of many migratory fish species in the Pacific Northwest have declined significantly over the last several decades. Many of these distinct populations have been granted protection under the federal Endangered Species Act (ESA). As a result, long-term recovery plans for these species include major operational changes to the region's hydroelectric projects, which have resulted in reductions in hydroelectric generation capacity and the seasonal shifting of hydroelectric generation from the fall and winter periods to the spring and summer periods. PGE has purchase contracts for power generated at affected facilities on the mid-Columbia River in central Washington and may be adversely affected by such reductions and seasonal shifting at those facilities. The timing of stored water releases also affects the availability and prices of power in the regional wholesale market.

PGE is implementing a series of fish protection measures at its hydroelectric generation projects on the Clackamas, Deschutes, and Willamette rivers that were prescribed by the U.S. Fish and Wildlife Service and the National Marine Fisheries Service under their authority granted in the ESA. As a result of measures contained in their operating license agreements, the Pelton/Round Butte and Willamette River projects have been certified as low impact hydro, with a portion of their output included as part of the Company's renewable energy portfolio used to meet the requirements of Oregon's Renewable Energy Standard. The following are related to conditions outlined in the Company's FERC operating license agreements:

- FERC approval of a 45-year license term for the Company's four hydroelectric projects on the Clackamas River is expected in 2010. Operating conditions proposed in the new license could result in a reduction in power production. Pending issuance of a new license, the project is operating under annual licenses issued by the FERC.
- As required by the FERC license for its Pelton/Round Butte project on the Deschutes River, which is in effect until 2055, PGE constructed a selective water withdrawal system in an effort to restore fish passage on the upper portion of the river. The system, which was placed in service in January 2010, is designed to collect juvenile salmon and steelhead, allowing them to bypass the dam when migrating to the Pacific Ocean. The system will also help regulate downstream water temperature.
- As required under the FERC license for its Willamette River hydroelectric project, in effect until 2035, PGE implemented several fish protection measures, the performance of which will receive ongoing evaluation.

Decommissioning of PGE's former Bull Run hydroelectric project, located in the Sandy River basin, has been substantially completed under a FERC Surrender Order. The project is no longer operating and remaining activity consists primarily of the removal and disposition of certain minor facilities.

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. Operation of electric transmission lines and wind generation projects can pose risks to a variety of such birds. PGE has developed and implemented an avian protection plan to reduce risks to bird species that can result from Company operations.

Hazardous Waste

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

PGE is also subject to regulation under the Comprehensive Environmental Response Compensation and Liability Act (CERCLA), referred to as Superfund. CERCLA can assert joint and several liability for investigation and remediation costs for designated Superfund sites. PGE is currently listed by the EPA as a Potentially Responsible Party (PRP) at two Superfund sites discussed as follows:

Portland Harbor—A 1997 investigation by the EPA of a segment of the Willamette River, known as the Portland Harbor, revealed significant contamination of river sediments. The EPA subsequently included Portland Harbor on the federal National Priority List as a Superfund site pursuant to CERCLA and listed sixty-nine PRPs, including PGE, which has historically owned or operated property near the river.

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.

For additional information on these EPA actions, see "Environmental Matters" in Note 18, Contingencies, in the Notes to Consolidated Financial Statements.

Under the Nuclear Waste Policy Act of 1982, the U.S. Department of Energy (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 for 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 plant site. The spent nuclear fuel is expected to remain at 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.

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 the OPUC authorizes PGE to charge for its retail services are a major factor in determining the Company's operating income, financial position, liquidity, and credit ratings. The OPUC has the authority to disallow recovery of any costs that it considers excessive or imprudently incurred. Furthermore, the regulatory process does not provide assurance that PGE will be able to achieve the earnings level authorized. Although the OPUC is required to establish rates that are fair, just and reasonable, it has significant discretion in determining the application of this standard.

In PGE's 2009 General Rate Case, the Company's initial proposal included an overall rate increase of 8.9%, compared to a 7.3% overall increase approved by the OPUC. The Company attempts to manage costs at levels consistent with the reduced rate increase. However, if the Company is unable to do so, or if such cost management results in increased operational risk, the reduced rate increase could adversely affect the Company's operations or results of operations. On February 16, 2010, PGE filed with the OPUC a general rate case with a 2011 test year (2011 General Rate Case). This 2011 General Rate Case seeks to more closely align customer prices with the Company's cost structure. There can be no assurance that the OPUC will approve the rate increase sought by PGE in this case. For additional information regarding the 2011 General Rate Case, see the Overview section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operation."

PGE utilizes a PCAM by which the Company can adjust future prices to reflect a portion of the difference between each year's forecasted and actual NVPC. Use of the approved cost sharing methodology requires that PGE absorb certain power cost increases before the Company is allowed to recover any amount from customers. Accordingly, application of the PCAM is expected to only partially mitigate the potentially adverse financial impacts of forced generating plant outages, severe weather, reduced hydro availability, and volatile wholesale energy prices. In 2009, PGE's actual NVPC exceeded the baseline NVPC included in prices by $22 million. As this amount was below the threshold for recovery under the PCAM, PGE absorbed these increased costs.

The current economic downturn has reduced the demand for electricity and has impaired the financial soundness of many customers, which has adversely affected PGE's results of operations and could continue to do so.

The economic slow-down has resulted in a rise in Oregon's average unemployment rate to 11.4% for 2009 from 6.4% for 2008 and 5.2% for 2007, compared to the national average unemployment rate of 9.3% for 2009. Oregon's seasonally-adjusted unemployment rate increased to 10.8% in December 2009 compared to 9% in December 2008. The slowing of the Oregon and national economies has resulted in reduced demand for electricity and could result in a continued reduction in such demand. This reduced demand has adversely affected the Company's results of operations and cash flow and could continue to do so. As a result of the economic slow down, PGE experienced, among other unfavorable trends, the following in 2009:

- A decrease of 9% in energy deliveries to industrial customers from 2008; and
- The sale of electricity, originally intended to meet forecasted retail load requirements, into a depressed wholesale market.

In addition, the Company's uncollectible customer accounts increased in 2009 compared to 2008. If customers are not successful in generating sufficient revenue or are unable to secure financing, they may not be able to pay, or may delay payment of, amounts owed to the Company. The inability of customers to pay the Company could adversely affect the Company's results of operations and cash flow.

Furthermore, as a result of the current economic downturn affecting the economies of the state of Oregon, the United States and other parts of the world, the Company's vendors and service providers could experience serious cash flow problems. As a result, PGE's vendors and service providers may be unable to perform under existing contracts or may significantly increase their prices or reduce their output or performance on future contracts.

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

Long-term increases in both the number of customers and demand for energy will require continued expansion and reinforcement of PGE's generation, transmission, and distribution systems. Construction of new generating facilities, or modifications to existing facilities, could be affected by various factors, including unanticipated delays and cost increases, which could result in the disallowance of certain costs in the rate determination process. In addition, the failure to complete construction projects according to specifications could result in reduced plant efficiency, equipment failure, and plant performance that falls below expected levels, which could increase operating costs.

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

Access to capital markets is important to PGE's ability to operate and to complete its ongoing capital projects, including Biglow Canyon Phase III, the smart meter project, and ongoing upgrades and replacements of transmission, distribution and generation infrastructure. In their normal course of business, credit rating agencies re-examine 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 Investor Service (Moody's) and/or Standard and Poor's Ratings Services (S&P) reduce their rating on the Company's unsecured debt to below investment grade, PGE could be subject to requests by certain wholesale counterparties to post additional performance assurance collateral, which could have an adverse effect on the Company's liquidity.

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

Access to capital and credit markets is important to PGE's ability to operate. The Company faces significant capital requirements in 2010 and for the next few years and expects to issue debt and equity securities in order to fund certain major projects. In addition, because of contractual commitments and regulatory requirements, the Company has limited ability to delay or terminate these projects, which include Biglow Canyon Phase III and the smart meter project in 2010. For additional information concerning PGE's capital requirements, see "Capital Requirements" in the Liquidity and Capital Resources section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

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

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

Performance of the capital markets affects the value of assets that are held in trust to satisfy future obligations under the Company's defined benefit pension plan. Sustained adverse market performance could result in lower rates of return for these assets than projected by the Company and could increase PGE's funding requirements related to the pension plan. Additionally, changes in interest rates affect the Company's liabilities under the pension plan. As interest rates decrease, the Company's liabilities increase, potentially requiring additional funding. During 2008, the value of the pension plan assets declined substantially, contributing to the pension plan's underfunded status of $120 million as of December 31, 2008. During 2009, the value of the pension plan assets appreciated and changes in certain actuarial assumptions resulted in an improvement in the underfunded status of the pension plan to $85 million as of December 31, 2009. As a result, the Company expects to make no contribution to the pension plan in 2010 and a $19 million contribution in 2011, pursuant to the requirements of the federal Pension Protection Act.

Performance of the capital markets also affects the 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 and a Supplemental Executive Retirement Plan. As changes in the 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. In 2008, PGE recorded a loss on the fair value of these assets of $17 million, which reduced net income by $12 million for the year ended December 31, 2008, while in 2009, PGE recorded a gain of $9 million, which increased net income by $5 million for the year ended December 31, 2009.

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

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, ultimately affecting the Company's liquidity and results of operations.

PGE purchases power and natural gas in the open market or pursuant to short-term, long-term or variable-priced contracts as part of its normal business operations. 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 the regulatory and legislative process 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 market value of derivative instruments and cash requirements to purchase power and natural gas. Although the Company's PCAM can be expected to partially mitigate adverse financial effects related to market conditions, cost sharing features of the mechanism do not provide for full recovery in customer prices.

If power and natural gas prices decline relative to the terms of PGE's existing purchased power and natural gas agreements, PGE may be required to provide increased margin deposits in accordance with these purchased power and natural gas agreements which could adversely affect the Company's liquidity. In the latter half of 2008 and into 2009, as a result of depressed wholesale power and natural gas prices, PGE was required to provide increased levels of margin deposits for its existing purchased power and natural gas agreements.

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 Company may not be able to fully recover these increased costs through ratemaking.

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 actions are subject to many uncertainties and management cannot predict the outcome of individual matters with assurance. The final resolution of some of the matters in which PGE is involved could require the Company to make additional expenditures, in excess of established accruals, 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 Note 18, Contingencies, in the Notes to Consolidated Financial Statements and Item 3.—"Legal Proceedings."

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

PGE expects that future federal, and possibly state, legislation or regulations may result in the imposition of limitations on greenhouse gas emissions from the Company's fossil fuel-fired electric generating facilities. Legislation has been introduced in the U.S. Congress that would require greenhouse gas emission reductions from such generating facilities and other sectors of the economy. No such legislation has yet been enacted, although the House of Representatives passed climate legislation in June 2009. Compliance with any greenhouse gas emission reduction requirements could require PGE to incur significant expenditures, including those related to carbon capture and sequestration technology, purchase of emission allowances and/or offsets, fuel switching, and/or retirement of high-emitting generation facilities and replacement with lower emitting generation facilities.

The cost to comply with expected greenhouse gas emissions reduction requirements is subject to significant uncertainties, including those related to the timing of the implementation of emissions reduction rules, required levels of emissions reductions, requirements with respect to the allocation of emissions allowances, the maturation, regulation and commercialization of carbon capture and sequestration technology, and PGE's compliance alternatives. Accordingly, the Company cannot estimate the effect of any such legislation on its results of operations, financial condition or cash flows; the cost to comply with such requirements, however, could be material. The Company would likely seek to recover such costs through the ratemaking process. However, there can be no assurance that such recovery would be granted.

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, full recovery is not assured. Inability to fully recover such costs in future rates could have a negative impact on the Company's results of operations. Extended maintenance and repair outages at Colstrip Unit 4 and Boardman resulted in incremental replacement power costs of $16 million in 2009.

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

PGE has revolving credit facilities with various banks for an aggregate amount available to the Company for general corporate purposes of $600 million. These credit facilities 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 Company is required to make certain representations to the banks each time it requests an advance under one of the credit facilities.

These credit facilities are commitments on the part of the banks to make loans and, in certain cases, to issue letters of credit. However, in the event of the occurrence of certain events 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 certain representations, in which case the banks would not be required to lend. PGE is also subject to the risk that one or more of the participating banks may default on their obligation to make loans under the credit facilities.

In addition, it is possible that the Company might not be aware of certain developments at the time it makes such a representation in connection with a request for an advance, 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, an acceleration of repayment of any outstanding advance.

Weather conditions that reduce stream flows, or unfavorable wind conditions, could adversely affect generation expected from PGE's hydro and wind resources and increase the Company's cost of generation or purchased power required to meet this energy gap.

PGE derives a portion of its power supply from its hydroelectric facilities and from hydroelectric facilities owned by certain public utility districts in the state of Washington and the City of Portland, with whom the Company has long-term power purchase contracts. Regional rainfall and snow pack levels affect stream flows and the resulting amount of generation available from these facilities. Shortfalls in low-cost hydro production would require increased generation from the Company's higher cost thermal plants and/or power purchases in the wholesale market, which could have an adverse effect on operating results.

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

Although the application of the PCAM could help mitigate adverse financial effects from any decrease in power provided by hydroelectric and wind resources, full recovery of any increase in power costs is not assured. Inability to fully recover such costs in future rates could have a negative impact on the Company's results of operations.

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

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

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

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

In June 2009, the OEQC adopted a rule as part of a separate regulatory process related to haze, mercury, and the Company's air permits that would require the installation of emissions controls at Boardman in three phases. The OEQC's rule has been submitted to the EPA for approval as part of the SIP. The Company expects the EPA to issue a decision on the SIP in 2010. For additional information, see "Environmental Matters" in Item 1.—"Business."

Although the full impact of required state and federal remediation measures is not yet determinable, they could have an adverse effect on future operations, operating costs, and generating capacity at both Boardman and Colstrip. The Company would seek to recover through the ratemaking process any costs of additional emission control equipment or emission reduction measures that may be required. However, there can be no assurance that such recovery would be granted.

In addition, PGE could be subject to litigation brought by environmental groups and other private parties alleging violations of state or federal law and seeking the imposition of penalties, damages, injunctive relief, and the closure of plants. For additional information, see Sierra Club et al. v. Portland General Electric Company in Item 3.—"Legal Proceedings."

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. Cost and availability of natural gas and coal can also impact the cost and output of the Company's thermal generating plants.

Capital expenditures and changes in operations 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 comprised of generation from hydroelectric projects on the Columbia, Clackamas, Deschutes, and Willamette rivers. Operation of these projects is subject to extensive regulation related to the protection of fish and wildlife. The listing of various species of salmon, wildlife, and plants as threatened or endangered has resulted in significant changes to federally-authorized activities, including those of hydroelectric projects. Salmon recovery plans could include further major operational changes to the region's hydroelectric projects, including those owned by PGE and those from which the Company purchases power under long-term contracts. In addition, 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 generation available to meet the Company's energy requirements. The Company would likely seek recovery of any such expenditures through the ratemaking process; however, there can be no assurance that such recovery would be granted.

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.

To the extent reasonably possible, PGE utilizes insurance to cost effectively mitigate the risk of physical loss or damage to the Company's property, excluding transmission and distribution property, resulting from natural disasters, subject to certain coverage terms and conditions. The Company would likely seek recovery of large storm-related losses to transmission and distribution property through the ratemaking process; however, there can be no assurance that any recovery would be granted. If such recovery is not granted, these increased costs could have an adverse effect on PGE's results of operations.

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

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

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

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

Conditions that may be imposed in connection with the renewal of hydroelectric licenses could require large capital expenditures.

PGE is currently involved in renewing the federal license for its hydroelectric projects on the Clackamas River. The FERC, under the Federal Power Act, may impose conditions with respect to environmental, operating and other matters in connection with the renewal of PGE's license. The Company cannot predict with certainty the requirements that might be imposed during the relicensing process, the economic impact of those requirements, whether a new license will ultimately be issued or whether PGE will be willing to meet the relicensing requirements to continue operating its Clackamas hydroelectric projects. The Company would likely seek recovery of any additional costs related to such licensing requirements through the ratemaking process.

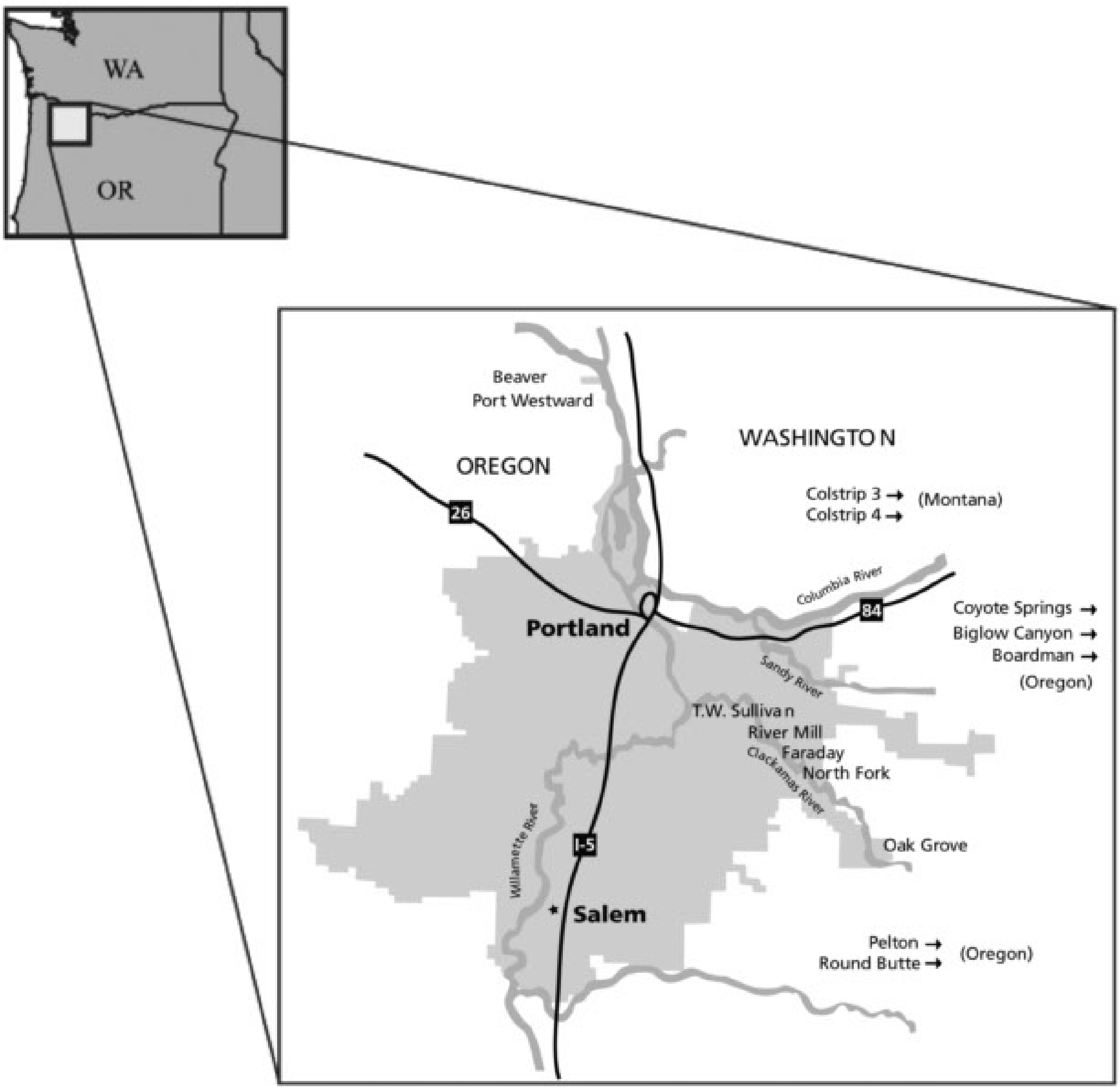
ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 2. PROPERTIES.

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

The Company's service territory and generating facilities are indicated below:



The following are generating facilities owned by PGE as of December 31, 2009:

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	529
Coyote Springs	Boardman, Oregon	233
Port Westward	Clatskanie, Oregon	413
Wind:		
Biglow Canyon Phase I	Sherman County, Oregon	125
Biglow Canyon Phase II	Sherman County, Oregon	150
Jointly-owned (2):		
Coal:		
Boardman (3)	Boardman, Oregon	374
Colstrip 3 and 4 (4)	Colstrip, Montana	296
Hydro:		
Pelton (5)	Deschutes River	73
Round Butte (5)	Deschutes River	225
Total net capacity		2,609 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 3 and 4 and PGE has a 20% ownership interest.
(5) PGE operates Pelton and Round Butte and has a 66.67% ownership interest.

Hydro Licensing

PGE holds FERC licenses under the Federal Power Act for its hydroelectric generating plants. The Company's Sullivan plant operates under a FERC license that expires in 2035, while the Pelton and Round Butte plants operate under a license that expires in 2055.

The Company filed an application with the FERC in 2004 to relicense the Clackamas River hydroelectric projects. A settlement agreement, resolving most of the issues raised in the relicensing proceeding and providing for a 45-year license term, was signed by the thirty-three participating parties in March 2006 and was submitted to the FERC for review and approval. PGE anticipates that the FERC will issue a decision on approval of a new license for the Clackamas River projects in 2010.

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 Interconnect. As of December 31, 2009, PGE owned an electric transmission and distribution system consisting of approximately:

Nominal Voltage Transmission and Distribution Lines (in kilovolts)	Circuit Miles
500	286
230	392
115	528
57	474
	1,680

In addition to the transmission and distribution lines presented in the table above, PGE has approximately 24,000 circuit miles of primary and secondary distribution lines that deliver electricity to its customers.

The Company also owns, or has contractual rights to, the following transmission facilities:

- From the Colstrip plant in Montana to PGE;
- Contractual rights to approximately 18% 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; and
- Long-term contractual rights for 100 MW of the Pacific DC Intertie between Celilo, Oregon and Sylmar in Southern California.

The California-Oregon AC Intertie and the Pacific DC Intertie are used primarily for the transmission of interstate purchases and sales of electricity among utilities, including PGE.

ITEM 3. LEGAL PROCEEDINGS.

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.

Following the closure of Trojan, 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 and PGE requested from the OPUC a Declaratory Ruling (Docket DR 10) regarding recovery of the Trojan investment and decommissioning costs. In August 1993, the OPUC issued a Declaratory Ruling in PGE's favor. The Declaratory Ruling was appealed to the Marion County Circuit Court, which in November 1994 upheld the OPUC's Declaratory Ruling. The Citizens' Utility Board (CUB) appealed the decision to the Oregon Court of Appeals.

In PGE's 1995 general rate case (Docket UE 88), 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 URP filed an appeal of the 1995 Order to the Marion County Circuit Court, alleging that the OPUC lacked authority to allow PGE to recover Trojan costs through its rates. 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 contradicted the Court's November 1994 ruling. The 1996 decision 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, where it was consolidated with the earlier appeal of the 1994 decision.

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, but upheld the OPUC's authority to allow PGE's recovery of its undepreciated investment in Trojan and its costs to decommission Trojan (1998 Decision). The court remanded the matter to the OPUC for reconsideration of its 1995 Order in light of the court's decision (1998 Remand).

In August 1998, PGE and the URP each filed a Petition for Review with the Oregon Supreme Court seeking review of that portion of the 1998 Decision relating to PGE's return on its undepreciated investment in Trojan. On November 19, 2002, the Oregon Supreme Court dismissed both Petitions for Review.

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 Settlement allowed PGE to remove from its balance sheet the remaining before-tax investment in Trojan of approximately $180 million at September 30, 2000, along with several largely offsetting regulatory liabilities. The URP did not participate in the Settlement and filed a complaint with the OPUC, challenging PGE's application for approval of the accounting and ratemaking elements of the Settlement.

In March 2002, after a full contested case hearing (Docket UM 989), 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. On November 7, 2003, the Marion County Circuit Court remanded the case to the OPUC to reduce rates or order refunds (2003 Remand). The opinion did not specify the amount or timeframe of any reductions or refunds. PGE and the OPUC each appealed the 2003 Remand to the Oregon Court of Appeals.

On October 10, 2007, the Oregon Court of Appeals issued an opinion that reversed the Settlement Order and remanded the Settlement Order to the OPUC for reconsideration. The Oregon Court of Appeals also vacated the 2003 Remand.

As a result of its reconsideration of the Settlement Order, the OPUC issued an order on September 30, 2008 that required PGE to refund $33.1 million to customers.

In the order, the OPUC also made the following findings:

- The OPUC has authority to order a utility to issue refunds under certain limited circumstances; and
- PGE's rates that were in effect for the period April 1, 1995 through September 30, 2000 were just and reasonable.

On October 22, 2008, the URP and the Class Action Plaintiffs (described in the Dreyer proceeding below) separately appealed the September 30, 2008 order to the Oregon Court of Appeals.

As of December 31, 2009, the Company had substantially completed the distribution of the $33.1 million refund, plus accrued interest, as required by the September 30, 2008 OPUC order.

Management cannot predict the ultimate outcome of the above matter. However, it believes that this matter will not have a material adverse impact on the financial condition of the Company, but may have a material adverse impact on the results of operations and cash flows in a future reporting period.

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.

On January 17, 2003, two class action suits were filed in Marion County Circuit Court against PGE on behalf of two classes of electric service customers. 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 charges its customers.

On April 28, 2004, the plaintiffs filed a Motion for Partial Summary Judgment and on July 30, 2004, PGE also moved for Summary Judgment in its favor on all of the Class Action Plaintiffs' claims. On December 14, 2004, the Judge granted the Plaintiffs' motion for Class Certification and Partial Summary Judgment and denied PGE's motion for Summary Judgment. On March 3, 2005, PGE filed a Petition for a Writ of Mandamus 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. On March 29, 2005, PGE filed a second Petition for an Alternative Writ of Mandamus with the Oregon Supreme Court seeking to overturn the Class Certification.

On August 31, 2006, the Oregon Supreme Court issued a ruling on PGE's Petitions for Alternative Writ of Mandamus 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.

On October 5, 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.

On October 17, 2007, the plaintiffs in the class action suits filed a motion with the Marion County Circuit Court to lift the abatement. On February 10, 2009, the Circuit Court judge denied the plaintiff's motion to lift the abatement.

Management cannot predict the ultimate outcome of the above matter. However, it believes that this matter will not have a material adverse impact on the financial condition of the Company, but may have a material adverse impact on the results of operations and cash flows in a future reporting period.

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).

On July 25, 2001, the FERC called for a preliminary evidentiary hearing to explore whether there may have been unjust and unreasonable charges for spot market sales of electricity in the Pacific Northwest from December 25, 2000 through June 20, 2001. During that period, PGE both sold and purchased electricity in the Pacific Northwest. In September 2001, upon completion of hearings, the appointed administrative law judge issued a recommended order that the claims for refunds be dismissed. In December 2002, the FERC re-opened the case to allow parties to conduct further discovery. In June 2003, the FERC issued an order terminating the proceeding and denying the claims for refunds. In November 2003 and February 2004, the FERC denied all requests for rehearing of its June 2003 decision. Parties appealed various aspects of these FERC orders to the U.S. Ninth Circuit Court of Appeals (Ninth Circuit).

On August 24, 2007, the Ninth Circuit issued its decision on appeal, concluding that the FERC failed to adequately explain how it considered or examined new evidence showing intentional market manipulation in California and its potential ties to the Pacific Northwest and that the FERC should not have excluded from the Pacific Northwest Refund proceeding purchases of energy made by the California Energy Resources Scheduling (CERS) division in the Pacific Northwest spot market. The Ninth Circuit remanded the case to the FERC to (i) address the new market manipulation evidence in detail and account for it in any future orders regarding the award or denial of refunds in the proceedings, (ii) include sales to CERS in its analysis, and (iii) further consider its refund decision in light of related, intervening opinions of the court. The Ninth Circuit offered no opinion on the FERC's findings based on the record established by the administrative law judge and did not rule on the FERC's ultimate decision to deny refunds. Two requests for rehearing were filed with the court and on April 9, 2009, the Ninth Circuit issued an order that denied the requests for rehearing. On April 16, 2009, the Ninth Circuit issued a mandate giving immediate effect to its August 24, 2007 order remanding the case to the FERC.

Since issuance of the mandate, certain parties proposing refunds have filed pleadings with FERC suggesting procedures on remand, attempting to initiate new proceedings, and containing additional evidence that they assert shows market-wide manipulation that justifies refunds from early in 2000. Parties opposing refunds, including PGE, have filed various pleadings that contest allegations of market-wide manipulation and urge the FERC to reaffirm, with a more detailed explanation of its consideration of market manipulation claims, its previous decision not to initiate proceedings to order refunds.

On September 4, 2009, various parties, including PGE, filed a petition for a writ of certiorari with the U.S. Supreme Court requesting that the Supreme Court review the decision of the Ninth Circuit in the Pacific Northwest Refund proceeding. In January 2010, the Supreme Court denied the petition for a writ of certiorari.

On May 17, 2007, the FERC approved a settlement between PGE and certain parties in the California refund case in Docket No. EL00-95, et seq. This resolves the claims as 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 21, 2001. The settlement with the California parties does not resolve potential claims from other market participants relating to transactions in the Pacific Northwest.

Management cannot predict the outcome of the Pacific Northwest Refund proceeding, or whether the FERC will order refunds in the Pacific Northwest, and if so, how such refunds would be calculated. Management believes that the outcome will not have a material adverse impact on the financial condition of the Company, but may have a material adverse impact on PGE's results of operations and cash flows in a future reporting period.

Sierra Club et al. v. Portland General Electric Company, U.S. District Court for the District of Oregon, Case No. CV 08-1136-HA.

On January 15, 2008, plaintiffs sent PGE a sixty-day notice of intent to sue for alleged violations of the federal Clean Air Act (CAA), Oregon's State Implementation Plan (SIP) at PGE's Boardman Coal Plant, and the Plant's CAA Title V permit. On September 30, 2008, the plaintiffs sued PGE for these and additional alleged violations of various environmental related regulations.

The plaintiffs seek injunctive relief that includes permanently enjoining PGE from operating the Boardman Coal Plant except in accordance with the CAA, Oregon's SIP, and the Plant's Title V Permit. In addition, plaintiffs seek civil penalties against PGE including $27,500 per day per alleged violation for violations occurring before March 15, 2004 and $32,500 per day per alleged violation occurring thereafter. The total amount of monetary penalties and damages asserted in the complaint cannot be determined with certainty. However, based solely on the complaint, the Company estimates that the amount is approximately $60 million.

On September 30, 2009, the District Court ruled on PGE's motion to dismiss most of the claims. In summary, the court denied PGE's motion with respect to most of the plaintiff's claims, but granted PGE's motion with respect to certain of the plaintiff's claims. The principal claims that remain are (i) that PGE constructed Boardman without complying with the 1974 and 1977 federal pre-construction permitting requirements, (ii) that PGE modified Boardman in the 1990s without complying with Oregon's pre-construction permitting requirements, and (iii) that certain modifications to Boardman triggered new source performance standards.

Management cannot predict the ultimate outcome of the above matter. However, the Company believes that it has strong defenses to the plaintiffs' claims and intends to vigorously defend against this lawsuit.

General

From time to time in the normal course of business, PGE is subject to various other regulatory proceedings, lawsuits, claims and other matters, certain of which may result in adverse judgments, settlements, fines, penalties, injunctions or other relief. Management currently does not believe any of these other matters will have a material adverse effect on the Company's financial position, results of operations or cash flows.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS.

None.

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 18, 2010, there were 1,182 holders of record of PGE's common stock and the closing sales price of PGE's common stock on that date was $19.10 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
Fiscal 2009:			
Fourth Quarter	$21.39	$18.25	$0.255
Third Quarter	20.95	17.69	0.255
Second Quarter	20.26	16.43	0.255
First Quarter	19.88	13.45	0.245
Fiscal 2008:			
Fourth Quarter	$24.55	$15.36	$0.245
Third Quarter	26.82	22.23	0.245
Second Quarter	24.92	22.44	0.245
First Quarter	27.70	21.89	0.235

While PGE expects to pay regular quarterly dividends on its common stock, 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 deem 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.

As required by Section 303A.12 of the NYSE Listed Company Manual, James J. Piro, the Chief Executive Officer of the Company, certified to the NYSE on June 4, 2009 that he was not aware of any violation by the Company of the NYSE's corporate governance listing standards.

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,				
	2009	2008	2007	2006	2005
	(In millions, except per share amounts)				
Statement of Income Data:					
Revenues	$1,804	$1,745	$1,743	$1,520	$1,446
Income from operations	208	217	269	159	172
Net income	89	87	145	71	64
Net income attributable to Portland General Electric Company	95	87	145	71	64
Earnings per share—basic and diluted	1.31	1.39	2.33	1.14	1.02
Dividends declared per common share	1.01	0.97	0.93	0.68	(a)
Statement of Cash Flows Data:					
Capital expenditures	696	383	455	371	255

	As of December 31,				
	2009	2008	2007	2006	2005
	(Dollars in millions)				
Balance Sheet Data:					
Total assets	$5,172	$4,889	$4,108	$3,767	$3,638
Total long-term debt (b)	1,744	1,306	1,313	1,003	890
Total Portland General Electric Company shareholders' equity	1,542	1,354	1,316	1,224	1,197
Common equity ratio	46.9%	47.3%	50.0%	53.0%	57.5%

(a) Not meaningful as PGE was a wholly-owned subsidiary of Enron.
(b) For 2006 and 2005, includes preferred stock subject to mandatory redemption requirements.

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

Information Regarding 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 relate to expectations, beliefs, plans, objectives for future operations, assumptions, business prospects, the outcome of litigation and regulatory proceedings, future capital expenditures, market conditions, future events, liquidity or performance, and other matters. Words or phrases such as "anticipates," "believes," "should," "estimates," "expects," "intends," "plans," "predicts," "projects," "will likely result," "will continue," or similar expressions are intended to identify such forward-looking statements.

Forward-looking statements are not guarantees of future performance and involve risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed. PGE's expectations, beliefs, projections and forecasts 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, data contained in the Company's records and other data available from third parties. There can be no assurance that PGE's expectations, beliefs or projections and forecasts will be achieved or accomplished.

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

- governmental policies and regulatory audits, investigations, and actions, including those of the FERC and OPUC with respect to allowed rates of return, financings, electricity pricing and price structures, acquisition and disposal of assets and facilities, operation and construction of plant facilities, transmission of electricity, recovery of power costs and capital investments, and current or prospective wholesale and retail competition;
- the continuing effects of the economic downturn in the state of Oregon, the United States and other parts of the world, including reductions in demand for electricity, sale of excess energy during periods of low wholesale market prices, impaired financial soundness 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 proceedings related to the Trojan Investment Recovery, the Pacific Northwest Refund proceeding, the Portland Harbor investigation, and other matters described in Note 18, Contingencies, in the Notes to Consolidated Financial Statements in Item 8 of this Annual Report on Form 10-K;
- operational factors affecting PGE's power generation facilities, including forced outages, hydro conditions, wind conditions, and disruption of fuel supply, which may result in repair costs as well as higher costs for replacement power;
- unanticipated delays and cost increases in connection with the construction or modification of generating facilities and other capital projects, which could result in the disallowance of certain costs pursuant to the rate determination process;
- capital market conditions, including interest rate volatility and reductions in demand for investment-grade bonds or 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;
- declines in the market prices of assets held by defined benefit pension plans and other benefit plans and decreases in the discount rate associated with plan liabilities that may result in increased funding requirements for such plans;

- wholesale prices for natural gas, coal, oil and other fuels and their impact on the availability and price of wholesale power in the western United States;
- declines in wholesale power and natural gas prices or reductions in PGE's credit rating below investment grade, which would require the Company to post additional collateral, in the form of either letters of credit or cash, to counterparties pursuant to existing power and natural gas purchase agreements;
- changes in residential, commercial, and industrial growth and demographic patterns in PGE's service territory;
- 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 pollution control equipment 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;
- unseasonable or extreme weather and other natural phenomena, which, in addition to affecting customer demand for power, could significantly affect PGE's ability and cost to procure adequate supplies of fuel or power to serve its customers, and could increase the costs to maintain the Company's generating facilities and transmission and distribution system;
- the effectiveness of PGE's risk management policies concerning the creditworthiness of its customers and counterparties;
- the effects of Oregon law related to utility rate treatment of income taxes, which may result in earnings volatility and adversely affect PGE's results of operations;
- the outcome of efforts to relicense the Company's Clackamas River hydroelectric projects, as required by the FERC;
- changes in, and compliance with, laws and policies concerning endangered species or protection of the environment;
- the effects of climate change, including effects on energy costs and consumption, as well as effects on the Company's operations and expenses;
- new federal, state, and local laws that could have adverse effects on operating results;
- employee workforce factors, including aging, potential strikes, work stoppages, and transitions in senior management;
- general political, economic, and financial market conditions;
- natural disasters and similar risks, such as earthquake, flood, drought, lightning, wind, and fire;
- acts of war or terrorism; and
- financial or regulatory accounting principles or policies imposed by governing bodies.

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

Overview

PGE is a vertically integrated electric utility engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the state of Oregon, as well as the wholesale sale of electricity and natural gas in the western 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 are subject to fluctuations during the year due to the impacts of seasonal weather conditions on demand for electricity, price changes, customer usage patterns (which are affected by the condition of the local economy), and the availability and price of purchased power and fuel. PGE is a winter peaking utility that typically experiences its highest retail energy sales during the winter heating season, with a slightly lower peak in the summer that generally results from air conditioning demand.

Future Energy Resource Strategy—In November 2009, PGE filed a new IRP that includes a four-year strategy for the acquisition of new resources and a 20-year strategy that outlines long-term expectations for resource needs and portfolio performance. PGE projects that it will need approximately 873 MWa of new resources by 2015, increasing to approximately 1,396 MWa by 2020, to meet customer demand. These requirements, primarily driven by continued load growth and the expiration of certain long-term power supply contracts, are expected to be met by energy efficiency measures, increased renewable resources, new transmission capability, and new generating plants.

Although the IRP as filed includes operating Boardman until 2040, the Company is exploring alternatives for the plant, including operating it until 2020 or using an alternative fuel source.

For additional information, see "Future Energy Resource Strategy" in the Power Supply section of Item 1.—"Business" and the Capital Requirements section in this Item 7.

General Rate Case—On February 16, 2010, PGE filed with the OPUC a 2011 General Rate Case, which is based on a 2011 test year. PGE filed for a $125 million increase in annual revenues, representing an approximate 7.4% overall increase in customer prices, which includes a 2% decrease related to projected power costs. In addition, PGE is proposing a capital structure of 50% debt and 50% equity, a return on equity of 10.5%, a cost of capital of 8.289%, an average rate base of approximately $3.2 billion, and the following:

- Modification of the PCAM for closer alignment with similar mechanisms of comparable electric utilities, with a symmetrical deadband of $10 million above or below the established net variable power cost baseline;
- Continuation of decoupling and certain other adjustment mechanisms;
- Plan to recover costs of future major storm damage;
- Recovery of carrying costs/benefits related to power supply collateral requirements; and
- Recovery of costs associated with the Company's defined benefit pension plan.

Based upon uncertainties related to the expected life and alternative operating plans for PGE's Boardman coal plant, the Company has included a separate tariff to implement necessary rate changes resulting from decisions regarding the future operation of the plant. For additional information, see *Boardman emissions controls* in the Capital Requirements section of Item 7.—"Management's Discussion and Analysis of Financial Condition and Results of Operations."

Regulatory review of the 2011 General Rate Case will continue throughout 2010, with a final order expected to be issued by the OPUC by mid-December 2010. New rates are expected to become effective January 1, 2011. Additional information regarding PGE's 2011 General Rate Case filing, including copies of direct testimony and exhibits, is available on the Company's Internet website at www.portlandgeneral.com. Information may also be obtained on the OPUC Internet website at www.puc.state.or.us.

Capital and Financing—PGE's 2009 and 2010 capital requirements are related primarily to the following major Board-approved projects and debt maturities:

- Construction of Biglow Canyon Phase II and III, the smart meter project, and ongoing capital expenditures for the upgrade, replacement, and expansion of transmission, distribution and generation infrastructure. Capital expenditures were $696 million in 2009 and are expected to approximate $540 million in 2010;

- The purchase of $142 million of Pollution Control Bonds in May 2009; and
- The maturity of $186 million of long-term debt in 2010.

To fund these projects and debt maturities, the Company issued $580 million of first mortgage bonds and 12,477,500 shares of common stock for net proceeds of $170 million in 2009. In addition, PGE expects cash from operations to be approximately $526 million in 2010 and plans to issue $250 million of long-term debt in 2010, of which $70 million was issued in January 2010.

Customers and Demand—The economic downturn resulted in an 11.4% unemployment rate in the state of Oregon as of December 31, 2009. As a result, the Company experienced an overall decrease of 3.3% in retail energy deliveries (2.4% weather adjusted) in 2009 compared to 2008. The following table indicates deliveries, by customer class, including Direct Access customers, during the past two years:

	2009		2008		
	Average Number of Customers	Energy Deliveries (1)	Average Number of Customers	Energy Deliveries (1)	Increase/ (Decrease) in Energy Deliveries
Residential	714,377	7,901	710,991	7,878	0.3%
Commercial	101,221	7,559	100,061	7,841	(3.6)
Industrial	271	3,876	263	4,275	(9.3)
Total	815,869	19,336	811,315	19,994	(3.3)%

(1) - In thousands of MWh.

Wholesale energy markets were also affected by the weak economy, with prices continuing at low levels. As a result of both lower prices and a reduction in energy sales, wholesale revenues in 2009 declined 43% from 2008.

The Company projects that weather adjusted retail energy deliveries will remain flat in 2010 due to the offsetting effects of continued weak employment and a moderate rebound in deliveries to industrial customers, including those in the high technology sector.

As indicated below, seasonally adjusted 2009 unemployment rates for the United States, the state of Oregon, and the Portland/Salem metropolitan area were all higher than in 2008. Further, unemployment rates for both Oregon and the Portland/Salem area exceeded the national average in both years. The majority of the Company's service territory lies within the Portland/Salem metropolitan area.

	United States	Oregon	Portland/ Salem
2009	9.3%	11.4%	11.0%
2008	5.8	6.4	6.1

Power Operations—PGE utilizes its own generating resources and wholesale market purchases to meet the energy and capacity needs of its customers. In 2009, the Company's generating plants provided approximately 57% of its retail load requirement, compared to 62% in 2008. The decrease in 2009 compared to 2008 was due to economic dispatch decisions and the following extended maintenance and repair outages in 2009:

- Colstrip Unit 4 is one of PGE's coal-fired thermal generating resources, providing approximately 6% (148 MW) of the Company's total generating capacity. In connection with its scheduled maintenance outage in March 2009, two turbine rotors were found to be damaged, with both sent to the manufacturer for repair. Colstrip Unit 4 was back online by the end of October 2009. PGE's incremental replacement power and repair costs were approximately $12 million and $1 million, respectively.

- Boardman is one of PGE's coal-fired thermal generating resources, providing approximately 14% (374 MW) of the Company's total generating capacity. Its scheduled maintenance outage in May 2009 was extended through mid-August 2009 due to high generator rotor vibrations. PGE's incremental replacement power costs were approximately $4 million, with the Company's share of repair costs not material.

Availability of the plants that PGE operates approximated 89% in 2009, 92% in 2008, and 93% in 2007. The availability of Colstrip, which PGE does not operate, approximated 68% in 2009, compared to 97% in 2008 and 87% in 2007. Although generation from PGE's hydroelectric plants provided approximately 10% of the Company's retail load requirement in 2009, 2008 and 2007, hydro generation decreased 1% in 2009 compared to 2008, with current forecasts indicating continued below normal regional hydro conditions for 2010.

Biglow Canyon Phase II, a 150 MW wind project, was completed in August 2009, with completion of Phase III, a 175 MW wind project, expected in the third quarter of 2010. These additions to PGE's generation portfolio are important steps in helping to meet Oregon's Renewable Energy Standard (RES). Wind generation increased 30% in 2009 compared to 2008 and provided 3% of PGE's retail load requirement in 2009 compared to 2% in 2008.

Legal, Regulatory and Environmental Matters—PGE is a party to certain proceedings whose ultimate outcome could have a material impact on the results of operations and cash flows in future reporting periods. These include 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 proceeding; and
- 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.

Boardman Deferral Amortization—On February 12, 2010, PGE received an order from the OPUC that granted the recovery of 50% of the $26.4 million of deferred excess replacement power costs associated with the forced outage of Boardman from November 18, 2005 through February 5, 2006. PGE had deferred such costs in accordance with an order issued by the OPUC on February 12, 2007, with amortization of the deferral to be determined in a future ratemaking proceeding that would include a prudency review of the Company's actions with respect to the outage and the acquisition of replacement power. Upon completion of the review, the OPUC concluded that a partially unsecured bearing pedestal was one of several factors that resulted in the outage. As a result, the OPUC concluded that partial recovery of the replacement power costs was warranted. In its order the OPUC authorized the collection of $13.2 million, plus interest (approximately $5.3 million as of December 31, 2009), of the deferred amount. Such recovery will be offset in the first quarter of 2010 with certain credits currently owed customers related to accrued savings on prior decommissioning activities at PGE's closed Trojan Nuclear Plant, with no impact on current customer prices. As a result of the reduction in the allowed recovery amount, the Company recorded a pre-tax write-off of approximately $18 million, including interest, in the fourth quarter of 2009.

The following retail price adjustments, as approved by the OPUC, became effective on January 1, 2010:

- Power Costs—Pursuant to the Annual Power Cost Update Tariff (AUT) process, PGE annually files an estimate of the following year's forecasted power costs. Under this process, new prices become effective January 1st each year. In the event a general rate case is filed in any given year, forecasted power costs would be included in such filing. The AUT for 2010 resulted in an overall 4.1% decrease in retail prices.

- Renewable Resources—Pursuant to a renewable adjustment clause mechanism (RAC), 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 submits an annual filing to the OPUC by April 1st each year, with rates 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 rates until the January 1st effective date of the new rates. Under this mechanism, PGE filed for recovery of its investments in Biglow Canyon Phase II and certain solar generating facilities in 2009, which resulted in an overall 2.5% increase in retail customer prices.
- PCAM—Customer refunds related to results of the 2007 PCAM, totaling $16 million, were completed in 2009, resulting in an approximate 1.1% increase in customer prices as the credits ended. There were no customer refunds or collections recorded in 2009 or 2008 pursuant to the PCAM.

The above items, combined with other miscellaneous tariff changes, result in an overall retail price decrease of approximately 1.8% effective January 1, 2010.

Rate actions pending as of January 1, 2010 include, but are not limited to, the following:

- Utility Rate Treatment of Income Taxes (SB 408)—PGE filed its report for 2008 with the OPUC reflecting the amount of taxes paid by the Company, as well as the amount of taxes authorized to be collected in rates. The report is being reviewed as part of a formal regulatory process, under which interested parties have reached an agreement that the appropriate refund due to customers is $10 million plus accrued interest, based on the OPUC's administrative rules that govern the calculation of the amount. Such amount is included in Regulatory liabilities as of December 31, 2009. The OPUC is expected to issue an order in April 2010, with customer refunds to begin on June 1, 2010.

  For 2009, PGE recorded an estimated $13 million refund to customers, which, if approved by the OPUC, would begin June 1, 2011.
- Selective Water Withdrawal project—In April 2009, during the final stages of construction, the structural failure of a major component of the Selective Water Withdrawal structure occurred during its installation. As a result, completion of the project, initially planned for the second quarter of 2009, was delayed until January 2010. On January 4, 2010, PGE and the other parties to the regulatory proceeding concerning rate recovery of the costs of the project entered into a stipulation settling all issues in the proceeding. The stipulation, which included a reduction of $6 million of certain capital costs related to a construction delay, allows PGE an annualized revenue requirement of $9.8 million, representing a 0.6% overall increase in customer prices. Such increase, which became effective on February 1, 2010, will remain in effect until new rates are established pursuant to the Company's 2011 General Rate Case.
- Decoupling Mechanism—First year results of the decoupling mechanism, which became effective on February 1, 2009, resulted in an approximate $6.8 million future refund to customers, as weather adjusted use per customer exceeded that included in PGE's 2009 General Rate Case. Such refunds, included in Regulatory liabilities as of December 31, 2009, will begin June 1, 2010, subject to review and approval by the OPUC.

The American Recovery and Reinvestment Act of 2009—On February 17, 2009, the American Recovery and Reinvestment Act of 2009 (the Act) was enacted. The Act includes provisions for several enhanced tax benefits, many of which are favorable to renewable energy and energy efficiency projects. For PGE's renewable energy projects, such as Biglow Canyon, the production tax credit was extended from 2009 through 2012. In addition pursuant to the Act, PGE was able to claim bonus depreciation in 2009. Bonus depreciation equals 50% of the basis of certain assets placed in service in the given year.

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 for 2009 compared to 2008, and for 2008 compared to 2007, which follow hereafter.

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

	Years Ended December 31,					
	2009		2008		2007	
	Amount	As % of Rev	Amount	As % of Rev	Amount	As % of Rev
Revenues, net	$1,804	100%	$1,745	100%	$1,743	100%
Operating expenses:						
Purchased power and fuel	944	52	878	50	879	50
Production and distribution	178	10	169	10	150	9
Administrative and other	179	10	190	11	184	11
Depreciation and amortization	211	12	208	12	181	10
Taxes other than income taxes	84	4	83	5	80	5
Total operating expenses	1,596	88	1,528	88	1,474	85
Income from operations	208	12	217	12	269	15
Other income (expense):						
Allowance for equity funds used during construction	18	1	9	1	16	1
Miscellaneous income (expense), net	3	—	(14)	(1)	8	—
Other income (expense), net	21	1	(5)	—	24	1
Interest expense	104	6	90	5	74	4
Income before income taxes	125	7	122	7	219	12
Income taxes	36	2	35	2	74	4
Net income	89	5	87	5	145	8
Less: net loss attributable to noncontrolling interests	(6)	—	—	—	—	—
Net income attributable to Portland General Electric Company	$ 95	5%	$ 87	5%	$ 145	8%

Revenues, energy sold and delivered (based on MWh), and retail customers consist of the following for the periods presented (dollars in millions and MWh in thousands):

	Years Ended December 31,					
	2009		2008		2007	
	Amount	As % of Total	Amount	As % of Total	Amount	As % of Total
Revenues:						
Retail sales:						
Residential	$ 794	44%	$ 758	44%	$ 716	41%
Commercial	619	35	598	34	593	34
Industrial	167	9	158	9	159	9
Total retail sales	1,580	88	1,514	87	1,468	84
Other retail revenues	77	4	4	—	60	4
Direct access customers	—	—	(10)	(1)	(12)	(1)
Total retail revenues	1,657	92	1,508	86	1,516	87
Wholesale revenues	112	6	195	11	201	12
Other operating revenues	35	2	42	3	26	1
Revenues, net	$ 1,804	100%	$ 1,745	100%	$ 1,743	100%
Energy sold and delivered (based on MWh):						
Retail energy deliveries:						
Residential	7,901	35%	7,878	34%	7,688	32%
Commercial	7,154	32	7,226	31	7,289	31
Industrial	2,364	11	2,472	11	2,485	11
	17,419	78	17,576	76	17,462	74
Direct access customers:						
Commercial	405	2	615	2	492	2
Industrial	1,512	7	1,803	8	1,673	7
	1,917	9	2,418	10	2,165	9
Total retail energy deliveries	19,336	87	19,994	86	19,627	83
Wholesale sales	2,896	13	3,190	14	4,042	17
Total energy sold and delivered	22,232	100%	23,184	100%	23,669	100%
Average number of retail customers:						
Residential	714,377	88%	710,991	88%	701,952	88%
Commercial	100,978	12	99,690	12	98,096	12
Industrial	253	—	217	—	217	—
Direct access	261	—	417	—	322	—
Total	815,869	100%	811,315	100%	800,587	100%

PGE's total system load and retail load requirement for the periods presented are as follows (MWh in thousands):

	Years Ended December 31,					
	2009		2008		2007	
Generation:						
Thermal:						
Natural gas	4,500	21%	4,460	20%	3,523	16%
Coal	3,760	18	4,994	23	5,051	22
Total thermal	8,260	39	9,454	43	8,574	38
Hydro	1,800	8	1,822	8	1,801	8
Wind	499	2	384	2	28	—
Total generation	10,559	49	11,660	53	10,403	46
Purchased power:						
Term purchases	6,437	30	5,569	25	7,598	33
Purchased hydro	2,801	13	3,037	14	3,300	15
Spot purchases	1,641	8	1,648	8	1,379	6
Total purchased power	10,879	51	10,254	47	12,277	54
Total system load	21,438	100%	21,914	100%	22,680	100%
Less: wholesale sales	(2,896)		(3,190)		(4,042)	
Retail load requirement	18,542		18,724		18,638	

Net income attributable to Portland General Electric Company for the year ended December 31, 2009 was $95 million, or $1.31 per diluted share, compared to $87 million, or $1.39 per diluted share, for the year ended December 31, 2008. An approximate 8% retail price increase, which became effective January 1, 2009, was offset by a 3% decline in retail energy deliveries resulting from the continued economic recession. Wholesale energy sales declined 9%, as power initially acquired to meet retail load was sold into a low-priced wholesale market. Also reducing net income were increased power costs, resulting primarily from the impact of an 8% shortfall in energy projected from hydro resources and higher costs to replace the output of both Colstrip and Boardman during their extended maintenance and repair outages. Incremental replacement power costs related to these outages amounted to $16 million in 2009.

The net effect of the following contributed to the increase in net income (net of income taxes):

- A $20 million increase from a provision for refund due to customers, recorded in 2008, related to the settlement of certain Trojan matters;
- A $17 million increase from a recovery in the fair value of non-qualified benefit plan trust assets. While 2009 fair value increases had a positive $5 million impact on net income, decreases in 2008 had a negative $12 million impact;
- A $5 million increase related to a reduction in employee benefit expenses;
- An $11 million decrease related to the fourth quarter 2009 write-off of a portion of a regulatory asset (including interest) representing deferred excess replacement power costs associated with Boardman's forced outage from late 2005 to early 2006. This adjustment was made pursuant to the February 12, 2010 OPUC order regarding ratemaking treatment for these costs;
- A $4 million decrease related to 2009 results of the decoupling mechanism; and
- A $4 million decrease related to certain capital costs expensed for the Selective Water Withdrawal project.

Net income attributable to Portland General Electric Company for the year ended December 31, 2008 was $87 million, or $1.39 per diluted share, compared to $145 million, or $2.33 per diluted share, for the year ended December 31, 2007. The decrease in net income was due primarily to the net effect of the following (net of income taxes):

- A $20 million decrease resulting from a provision for a future refund to customers, related to the Trojan order;
- A $17 million decrease resulting from the impact of SB 408, with a $6 million customer refund recorded in 2008 and an $11 million collection recorded in 2007;
- A $16 million decrease from the after-tax impact of the deferral in 2007 of a portion of Boardman excess replacement power costs (including accrued interest) for potential future recovery (as approved by the OPUC);
- A $15 million decrease from a decline in the fair market value of non-qualified benefit plan trust assets. While 2007 fair market value increases had a positive $3 million impact on net income, decreases in 2008 had a negative $12 million impact; and
- A $6 million increase from gains realized on the sale of fuel oil in 2008.

Operating results were also affected by increased production and distribution and administrative and other expenses in 2008 relative to 2007, which were partially offset by a 2% increase in both retail energy deliveries and average price.

2009 Compared to 2008

Revenues increased $59 million, or 3%, in 2009 compared to 2008 as a result of the net effect of the items discussed below.

Total retail revenues increased $149 million, or 10%, due primarily to the following:

- A $125 million increase resulting from higher average prices, driven primarily by OPUC—approved price increases in PGE's 2009 General Rate Case, which became effective January 1, 2009;
- A $33 million increase resulting from the accrual of refunds to customers related to certain Trojan matters, which is reflected as a reduction to Other retail revenues in 2008;
- An $11 million increase related to cost recovery of Biglow Canyon Phase II, included in Other retail revenues;
- A $10 million increase resulting from a reduction in transition adjustment credits provided to Direct Access customers. Such credits are based on the difference between the cost and market value of PGE's power supply;
- A $14 million decrease driven by a decline in retail energy deliveries, with the impact of the continued economic slowdown in 2009 only partially offset by an increase in the average number of customers served during the year. Economic shutdowns by some large industrial customers contributed to a 9.3% decrease in energy deliveries to industrial customers;
- A $10 million decrease in supplemental tariffs, which is fully offset in Depreciation and amortization expense; and
- A $7 million decrease related to the decoupling mechanism, which went into effect on February 1, 2009 (included in Other retail revenues).

Heating degree-days in 2009 decreased 7.8% compared to 2008, while cooling degree-days, which were 34% greater than the 15-year average, increased 32%. The following table indicates the number of heating and cooling degree-days for the periods presented, along with 15-year averages provided by the National Weather Service, as measured at Portland International Airport:

	Heating Degree-Days		Cooling Degree-Days	
	2009	2008	2009	2008
1st Quarter	2,022	1,981	—	—
2nd Quarter	578	860	90	98
3rd Quarter	63	80	537	376
4th Quarter	1,561	1,661	—	—
Year-to-date	4,224	4,582	627	474
15-year average for the year-to-date	4,169	4,169	467	467

On a weather adjusted basis, retail energy deliveries decreased 2.4% in 2009 compared to 2008, with deliveries to residential, commercial, and industrial customers increasing (decreasing) by 1.1%, (2.7)%, and (8.4)%, respectively. PGE forecasts total weather adjusted energy deliveries for 2010 will be flat relative to 2009.

In addition to those items listed above as "included in Other retail revenues," Other retail revenues includes certain customer credits and refunds that are fully offset in Retail sales, therefore having no impact to Total retail revenues. These consist primarily of the following items:

- A $19 million increase related to the resumption of customer credits pursuant to the Residential Exchange Program administered by the Bonneville Power Administration, which resulted in an average price reduction of approximately 6.3% for residential and small farm customers, effective April 15, 2008; and
- An $18 million increase, reflecting customer refunds related to results of the 2007 PCAM, which were made during 2009.

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 contacts. Such sales can vary significantly from year to year as a result of economic conditions and customer demand.

The national economic downturn has resulted in both lower wholesale energy sales and prices due to a reduction in both actual and projected demand for electricity. In 2009, electricity demand by PGE customers was less than projected, with excess power, initially acquired to meet retail load, sold into a low-priced wholesale market. Also contributing to lower wholesale energy sales was the combined effect of the Company's requirement to replace the output of Colstrip and Boardman during their extended outages and lower than projected hydro production. Wholesale revenues in 2009 decreased $83 million, or 43%, from 2008 as a result of the following:

- A $65 million decrease related to a 37% decline in average wholesale prices, driven by lower natural gas and electricity prices; and
- An $18 million decrease due to a 9% decline in wholesale energy sales volume.

Other operating revenues decreased $7 million, or 17%, primarily due to fuel oil sales of $8 million in 2009 from the Company's Beaver generating plant compared to $15 million in 2008. Such sales resulted in realized gains of $3 million in 2009 and $11 million in 2008.

Purchased power and fuel expense includes the cost of power purchased and fuel used to generate electricity to meet PGE's energy requirements, as well as the cost of settled electric and natural gas financial contracts. In 2009, Purchased power and fuel expense increased $66 million, or 8%, from 2008. The increase consisted of $69 million related to an 8% increase in average variable power cost and $18 million related to the write-off of a portion of a regulatory asset representing deferred excess replacement power costs associated with Boardman's forced outage from late 2005 to early 2006. These increases were partially offset by the $20 million impact of a 2% decrease in total system load, which includes the impact of lower wholesale sales. The increase was due to the net effect of the following:

- A $63 million, or 12%, increase in the cost of purchased power, resulting from a 6% increase in both purchases and average cost. Increased purchases were required to replace the output of Colstrip and Boardman during extended maintenance and repair outages at these plants in 2009, resulting in incremental replacement power costs of approximately $16 million. A decrease in energy received under contracts with mid-Columbia hydroelectric projects contributed to the increase in the average cost;
- An $18 million increase related to the write-off of a portion of a regulatory asset consisting of deferred excess replacement power costs associated with Boardman's forced outage discussed above; and
- A $14 million, or 4%, decrease in the cost of thermal production, resulting primarily from a 25% decrease in generation at Colstrip and Boardman as a result of their extended outages and a 2% decrease in the average cost of natural gas-fired generation. These decreases were partially offset by the impact of a 13% increase in the average cost of coal-fired generation and a 1% decrease in PGE hydro production.

Pursuant to the PCAM, in 2009 PGE's actual NVPC was $22 million above the baseline, but within the established deadband of $15 million below and $29 million above 2009 forecasted NVPC. Accordingly, no collection from customers was recorded in 2009. In 2008, PGE's actual NVPC was $31 million below the baseline and $17 million below the established deadband of $14 million below the 2008 forecasted NVPC, resulting in a potential refund due to customers. However, based on results of the regulated earnings test, which was approved by the OPUC, no refund to customers was recorded in 2008. Preliminary estimates indicate that the 2010 deadband will range from $17 million below to $34 million above 2010 forecasted NVPC.

The average variable power cost of PGE's total system load was $43.22 and $40.01 per MWh in 2009 and 2008, respectively, an increase of 8%. The 2009 average variable power cost excludes the effect of the $18 million write-off of deferred excess replacement power costs related to Boardman's forced outage from late 2005 to early 2006.

Regional hydro conditions were below normal in 2009, with PGE-owned hydro production and energy received from mid-Columbia projects down 1% and 8%, respectively, from 2008. Current forecasts indicate that regional hydro conditions in 2010 will again be below normal levels. 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.

The following indicates the forecast of the April-to-September 2010 runoff (issued February 18, 2010) compared to the actual runoffs for 2009 and 2008 (as a percentage of normal, as measured over the 30-year period from 1971 through 2000):

Location	2010 Forecast	2009 Actual	2008 Actual
Columbia River at The Dalles, Oregon	71%	85%	101%
Mid-Columbia River at Grand Coulee, Washington	79	80	102
Clackamas River	78	122	163
Deschutes River	76	92	101

Production and distribution expense increased $9 million, or 5%, in 2009 compared to 2008, primarily due to the net effect of the following:

- A $6 million increase related to certain capital costs expensed for the Selective Water Withdrawal project, pursuant to a stipulation with the OPUC;
- A $4 million increase in maintenance costs at Colstrip Unit 4, consisting of $3 million related to an extended overhaul and $1 million for the repair of damaged turbine rotors;
- A $4 million increase related to cost escalation provisions in Coyote Spring's long-term service agreement (fully offset in Depreciation and amortization expense);
- A $3 million increase for repair and restoration activities, related primarily to 2009 wind storms;
- A $6 million decrease related to the deferral of certain plant maintenance costs at Boardman, Beaver, and Colstrip. As authorized by the OPUC in PGE's 2009 General Rate Case, certain maintenance costs that exceed those covered in current prices are deferred and amortized over ten years, beginning in 2009; and
- A $2 million decrease in planned maintenance outage expenses at Boardman.

Administrative and other expense decreased $11 million, or 6%, in 2009 compared to 2008, primarily due to the net effect of the following:

- An $8 million decrease in incentive compensation, due to changes in the provisions of officer and employee plans that resulted in reduced awards based on 2009 performance;
- A $3 million decrease in customer support expenses, including reductions related to implementation of the smart meter project;
- A $5 million decrease related to both the settlement of a legal claim in 2008 and lower legal and general support expenses in 2009; and
- A $5 million increase in employee benefit expenses, related primarily to pension and healthcare costs.

Depreciation and amortization expense increased $3 million, or 1%, in 2009 compared to 2008, due largely to the net effect of the following:

- A $14 million increase in depreciation related to Biglow Canyon Phase II, the smart meter project, and other capital additions in 2009;
- A $5 million increase related to impairment losses recognized on photovoltaic solar power facilities, the majority of which was allocated to noncontrolling interests through the Net loss attributable to the noncontrolling interests. For additional information, see Note 16, Variable Interest Entities, in the Notes to Consolidated Financial Statements included in Item 8—"Financial Statements";
- A $10 million decrease related to the 2008 recovery of certain regulatory assets (fully offset in Retail sales);
- A $4 million decrease related to the regulatory deferral of certain plant maintenance expenses at Coyote Springs (fully offset in Production and distribution expense); and
- A $3 million decrease resulting from a reduction in the deferral of certain Oregon tax credits for future ratemaking treatment, as the Company was unable to utilize such credits (offset in Income taxes).

Taxes other than income taxes increased $1 million, or 1%, in 2009 compared to 2008, due primarily to higher franchise fees resulting from increased retail revenues.

Other income (expense), net was $21 million in 2009 compared to ($5) million in 2008. The change is primarily due to the net effect of the following:

- A $26 million increase in income from non-qualified benefit plan trust assets, resulting from a $9 million increase in the fair value of the plan assets in 2009 compared to a $17 million decrease in 2008;
- An $8 million increase in the allowance for equity funds used during construction, as a result of higher construction work in progress balances during 2009, related primarily to Biglow Canyon Phases II and III; and
- A $7 million decrease in miscellaneous income, resulting primarily from lower interest on regulatory assets and money market account balances.

Interest expense increased $14 million, or 15%, in 2009 compared to 2008 primarily due to the net effect of the following:

- An $18 million increase resulting from a higher average long-term debt balance during 2009 compared to 2008, related primarily to issuances of first mortgage bonds in 2009 to fund the construction of new generating facilities. In 2009, the average balance of long-term debt outstanding was $1,525 million compared to $1,310 million in 2008;
- A $2 million increase in credit facility fees; and
- A $6 million decrease resulting from an increase in the allowance for funds used during construction, related primarily to the construction of Biglow Canyon Phases II and III.

Income taxes increased $1 million, or 3%, in 2009, with an effective tax rate of 28.8% in 2009, comparable to the 28.4% rate in 2008.

In January 2010, an increase in the state corporate tax rate became effective, retroactive to January 1, 2009. The increase in the state corporate tax rate is substantially offset by the effects of SB 408. Accordingly, the increase is not expected to have a significant impact on the Company's future results of operations.

Net loss attributable to noncontrolling interests of $6 million represents the noncontrolling interests' portion of the net loss of PGE's less-than-wholly-owned subsidiaries, the majority of which consists of the impairment losses recognized on the photovoltaic solar power facilities, discussed previously in Depreciation and amortization.

2008 Compared to 2007

Revenues in 2008 were comparable to 2007, with an increase of $2 million, which is the result of the following offsetting factors:

Total retail revenues decreased $8 million, or 1%, due primarily to the following offsetting factors:

- A $33 million decrease related to the accrual of refunds to customers pursuant to the OPUC order issued September 30, 2008 related to certain Trojan matters;
- A $28 million decrease related to SB 408, with an estimated refund to customers of $10 million recorded in 2008, resulting primarily from the Trojan order, compared to an estimated collection from customers of $18 million recorded in 2007;
- A $36 million increase resulting from a 2% increase in average price, which was driven by price increases for the Company's smart meter project and recovery of Biglow Canyon Phase I, partially offset by a price decrease for changes in forecasted 2008 power and fuel costs;

- A $10 million increase resulting from a 2% increase in total retail energy deliveries, due to more extreme weather conditions in 2008, as indicated in the table below, and a 1.3% increase in the average number of customers served in 2008 compared to 2007; and
- A $5 million increase in supplemental tariffs, which are fully offset in depreciation and amortization.

The following table indicates the number of heating and cooling degree-days for the periods presented, along with 15-year averages provided by the National Weather Service, as measured at Portland International Airport:

	Heating Degree-Days		Cooling Degree-Days	
	2008	**2007**	**2008**	**2007**
1st Quarter	1,981	1,852	—	—
2nd Quarter	860	698	98	56
3rd Quarter	80	123	376	344
4th Quarter	1,661	1,701	—	—
Year-to-date	4,582	4,374	474	400
15-year average for the year-to-date	4,169	4,161	467	454

On a weather adjusted basis, retail energy deliveries increased 0.8% in 2008 compared to 2007, with deliveries to residential, commercial, and industrial customers increasing (decreasing) by 1.0%, (0.4)%, and 2.9%, respectively.

Other retail revenues for 2008 and 2007 include $34 million and $42 million, respectively, in customer credits under the Residential Exchange Program administered by the BPA, with such amounts fully offset within Retail sales to residential and commercial customers.

Wholesale revenues in 2008 decreased $6 million, or 3%, from 2007 as a result of:

- A $42 million decrease related to a 21% decrease in wholesale energy sales; partially offset by
- A $36 million increase related to a 23% increase in average sales price, driven by higher natural gas prices and lower regional hydro availability.

Other operating revenues increased $16 million, or 62%, primarily due to fuel oil sales of $15 million in 2008.

Purchased power and fuel expense for 2008 decreased slightly from 2007 as a result of the following offsetting factors:

- A $69 million, or 12%, decrease in the cost of purchased power resulting from a 16% decrease in purchases, partially offset by a 4% increase in the average cost of purchased power. The addition of Port Westward in June 2007 and Biglow Canyon Phase I in December 2007 to the Company's generating portfolio resulted in reduced reliance on purchased power from the wholesale market;
- A $15 million decrease in the estimated amount recorded for future refund to customers under the PCAM. In 2008, PGE's actual NVPC was less than the $13.8 million deadband threshold by approximately $17 million, resulting in a refund calculation comparable to that of 2007. However, based on the results of a regulated earnings test, no refund was recorded in 2008;
- A $58 million, or 19%, increase in the cost of thermal generation, driven by a 12% increase in generation and a 7% increase in the average cost of power generated. Generation as a percent of total system load increased to 53% in 2008 compared to 46% in 2007. This increase was largely driven by a 27% increase in gas-fired generation due to the addition of Port Westward;
- A $20 million increase related to the deferral of excess Boardman power costs in 2007, which were incurred in late 2005 and early 2006; and
- A $5 million increase due to a reduction in the Company's wholesale credit reserve in 2007, primarily as a result of a settlement with certain California parties involving transactions in 2000-2001.

The average variable power cost of PGE's total system load was $40.01 and $39.19 per MWh in 2008 and 2007, respectively, an increase of 2%. Averages exclude the effect of amounts related to regulatory power cost deferrals and wholesale credit provisions.

Energy from hydro resources decreased 5% in 2008 compared to 2007 and represented 26% and 27% of PGE's retail load requirement in 2008 and 2007, respectively. Reduced energy received pursuant to contracts with mid-Columbia projects during 2008 was largely offset by increased energy from Company-owned hydro resources.

Production and distribution expense increased $19 million, or 13%, in 2008 compared to 2007, due to the following:

- A $7 million increase in operating costs at the Company's generating facilities, including Port Westward and Biglow Canyon Phase I;
- A $4 million increase related to line maintenance, including locating expense related to the installation of fiber optic lines by other utilities and increased tree trimming;
- A $4 million increase resulting from a higher number of employees and general wage increases;
- A $3 million increase resulting from higher maintenance and repair expenses incurred at the Boardman and Beaver plants in connection with scheduled maintenance activities in 2008; and
- A $1 million increase related to the December 2008 snow and ice storm, net of a $7 million expected insurance recovery.

Administrative and other expense increased $6 million, or 3%, in 2008 compared to 2007, due to the following:

- A $3 million increase associated with higher uncollectible retail customer accounts. In 2008, the provision for the allowance for uncollectible accounts increased $2 million, which was driven by the weakening of the economy, compared to a decrease of $1 million in 2007;
- A $2 million increase related to the settlement of a legal claim; and
- A $2 million increase in legal fees, including those related to the Company's 2009 General Rate Case proceedings and other regulatory matters.

Depreciation and amortization expense increased $27 million, or 15%, in 2008 compared to 2007, due largely to the net effect of the following:

- A $17 million increase in depreciation related to capital plant additions, consisting primarily of $15 million for Port Westward and Biglow Canyon Phase I;
- An $8 million increase related to the accelerated depreciation of existing meters that were replaced as part of the Company's smart meter project;
- A $5 million increase related to the refund of regulatory liabilities during 2007 (fully offset in Retail sales); and
- A $3 million decrease in the amortization of computer software.

Taxes other than income taxes increased $3 million, or 4%, in 2008 compared to 2007, due primarily to higher property taxes resulting from increases in assessed values, increased franchise fees resulting from higher retail revenues, and an increase in payroll taxes.

Other income (expense), net was ($5) million in 2008 compared to $24 million in 2007. The change is due primarily to the following:

- A $22 million decrease in income from non-qualified benefit plan trust assets resulting from a $17 million decrease in the fair value of the plan assets during 2008 compared to a $5 million increase in 2007; and
- A $7 million decrease in the allowance for equity funds used during construction, which resulted from lower construction work in progress balances during 2008 due to the completion of both Port Westward and Biglow Canyon Phase I in 2007.

Interest expense increased $16 million, or 22%, in 2008 compared to 2007, due primarily to the following:

- A $13 million increase resulting from a higher level of outstanding long-term debt related to the issuance of additional first mortgage bonds during the second half of 2007 and into 2008. During 2008, the average outstanding balance of long-term debt was $1,310 million compared to $1,158 million for 2007; and
- A $3 million increase resulting from a decrease in the allowance for funds used during construction, which was driven by lower construction work in progress balances during 2008 compared to 2007.

Income taxes decreased $39 million, or 53%, in 2008 compared to 2007, with an effective tax rate of 28.4% in 2008 compared to 33.8% in 2007. These decreases are due primarily to lower taxable income and an increase of $9 million in federal and state energy tax credits generated from the operation of Biglow Canyon Phase I in 2008.

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 may adversely affect the Company's access to capital, cost of capital, and ability to execute its business plan as scheduled." in Item 1A.—"Risk Factors."

Capital Requirements

PGE has undertaken projects which will require significant capital spending during the next several years. The following table indicates projected cash requirements for 2010 through 2014, and actual capital expenditures for 2009 (in millions):

	Years Ending December 31,					
	2009	2010	2011	2012	2013	2014
Ongoing capital expenditures	$214	$260	$235 - $255	$225 - $245	$235 - $255	$275 - $295
Biglow Canyon Phase II	222	—	—	—	—	—
Biglow Canyon Phase III	166	210	—	—	—	—
Hydro licensing and construction	18	15	$90 - $110			
Smart meter project	79	40	—	—	—	—
Boardman emissions controls (1)	1	15	$10 - $30		—	—
Total capital expenditures	$700(2)	$540				
Long-term debt maturities		$186	$ —	$ 100	$ 100	$ 73

(1) Represents 80% of estimated total costs based on installation of nitrogen oxide and mercury controls to meet regulatory requirements. In 1985, PGE sold an undivided 15% interest in Boardman to a third party, reducing the Company's ownership interest from 80% to 65%. The purchaser has certain rights to participate in the financing of the portion of the total capital cost attributable to its interest. If the purchaser does not exercise its rights to finance the portion of the total cost attributable to its interest, PGE's share of the total cost for the emissions controls at Boardman is expected to be 80%.

(2) Differs from amount reported on statement of cash flows and includes preliminary engineering and retirement costs and excludes amount expensed related to the Selective Water Withdrawal project.

Estimated future expenditures related to the addition or modification of energy resources and a significant new high voltage transmission project (the Cascade Crossing project) pursuant to PGE's IRP are not included in the table above and include:

- The construction of Cascade Crossing project at an estimated total cost of $610 million to $825 million, with an estimated in service date of 2015;
- The installation of certain emissions controls at Boardman, as discussed below in *Boardman emissions controls*; and
- Other projects included in the Company's IRP. The timing and total cost of any project, which would be subject to a formal bidding process, are not certain at this time.

For additional information, see "Future Energy Resource Strategy" in the Power Supply section and the Transmission and Distribution section of Item 1.—"Business."

The following provides information regarding the items presented in the table above.

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

Biglow Canyon—Phase II of Biglow Canyon, with an installed capacity of 150 MW and a total cost of $321 million (including $12 million of AFDC), was completed in August 2009. Construction of Phase III, with an installed capacity of 175 MW and an estimated cost of $428 million (including $23 million of AFDC), is continuing, with completion expected in the third quarter of 2010.

Hydro licensing and construction—As required under the 50-year license that the FERC issued to PGE in 2005 for its Pelton/Round Butte project on the Deschutes River, PGE began construction of a selective water withdrawal system in late 2007 in an effort to restore fish passage on the upper portion of the river. The system is designed to collect juvenile salmon and steelhead, allowing them to bypass the dam when migrating to the Pacific Ocean, and regulate downstream water temperature. As a result of a delay in construction, completion of the system, initially planned for the second quarter of 2009, occurred in January 2010. PGE's portion of the total cost, including AFDC and costs incurred due to the delay, was approximately $85 million.

The Company filed an application with the FERC in 2004 to relicense the Clackamas River hydroelectric projects. A settlement agreement, resolving most of the issues raised in the licensing proceeding and providing for a 45-year license term, was signed by the thirty-three participating parties in March 2006 and was submitted to the FERC for review and approval. Capital spending requirements reflected in the table above relate primarily to modifications to the projects to enhance fish passage and survival, as required by conditions contained in the settlement agreement. Pending issuance of the new license, the project is operating under annual licenses issued by the FERC. PGE anticipates that the FERC will issue a decision on approval of a new license for the Clackamas River projects in 2010.

Smart meter project—The Company has installed approximately 450,000 new customer smart meters as of December 31, 2009. A total of 850,000 new customer smart meters is expected to be installed, with the remainder expected to be installed in 2010. This project, which enables two-way remote communication with the Company, is expected to provide improved services, operational efficiencies, and a reduction in future operating expenses. The capital cost of this project is estimated at $130 million to $135 million, excluding AFDC.

Boardman emissions controls—In accordance with federal regional haze rules, the DEQ conducted an assessment of emissions sources which indicated that Boardman would be subject to a Regional Haze Best Available Retrofit Technology (BART) Determination, as required under the Clean Air Act.

Pursuant to the BART Determination process, in June 2009, the OEQC adopted a rule that would require the installation of controls at Boardman in three phases. The first phase would require installation of controls for nitrogen oxides (NO_X), with estimated completion by July 1, 2011. The second phase would address mercury and sulfur dioxide removal using a semi-dry scrubber and bag house, with estimated completion by July 1, 2014. The first two phases would meet federal requirements for installing BART. The third phase, which would require the installation of Selective Catalytic Reduction (SCR) for additional NO_X control, with estimated completion by July 1, 2017, would meet regulatory requirements for reasonable progress towards haze emissions reduction goals. The OEQC rule has been submitted to the EPA for approval as part of the Oregon Regional Haze State Implementation Plan (SIP). The Company expects the EPA to issue a decision on the SIP in 2010. PGE estimates that the approximate cost of the controls required by the OEQC rule under the three phases would be between $520 million and $560 million (100% of total costs, excluding AFDC). These cost estimates are preliminary and subject to change. The Company will continue to seek recovery of its costs through the ratemaking process.

PGE submitted its most recent IRP to the OPUC in November 2009. In that plan, given the options provided by the OEQC of either ceasing operation of Boardman or installing controls and continuing operations, the Company recommended the long-term continued operation of Boardman through 2040 with the addition of the controls called for in the OEQC rule. This determination was made based upon the expected cost and risks relating to (i) carbon dioxide emissions, (ii) replacement generation, (iii) coal and natural gas, and (iv) emissions controls required to meet the OEQC's rule. For additional information concerning the IRP, see the "Future Energy Resource Strategy" in the Power Supply section of Item 1.—"Business."

Continuing discussions with IRP stakeholders indicate support for the analysis of an alternative strategy regarding Boardman. PGE is committed to seeking the best plan to provide reliable and reasonably priced electricity for customers. Accordingly, the Company informed the OPUC that it intends to consider an alternative operating plan for Boardman, under which the plant would either discontinue the use of pulverized coal as a fuel source, or cease operation in 2020 and be replaced with a new base load resource. As a result, the Company requested that the OPUC delay consideration of the IRP to allow for additional analysis. The Company intends to file an addendum to its IRP during March 2010, following the presentation of the Company's proposal to intervenors in this matter.

If agreement with regulatory bodies cannot be reached for an alternative plan, PGE will continue to seek approval for the installation of all required emissions controls and continued operation of the plant through 2040. Regardless of whether the plant continues to operate through 2020 or 2040, the Company intends to install emissions controls for nitrogen oxide and mercury at a total cost of approximately $40 million, excluding AFDC. The Company's share of these costs of approximately $32 million is included in the table above. Costs associated with the semi-dry scrubber, bag house, and SCR controls are not included in the table due to uncertainties with respect to their installation.

In the event of a 2020 closure, the Company would seek to recover in future rates its remaining investment in Boardman (approximately $125 million as of December 31, 2009), plus the cost of the mercury controls, low nitrogen oxide burners and decommissioning and other costs related to the plant's closure, as well as the construction or acquisition costs of replacement generating capacity. It is estimated that accelerating the recovery of such costs over ten years rather than 30 years would result in an approximate 1% increase in customer prices.

In June 2008, PGE received a request for information from the EPA under section 114 of the Clean Air Act (CAA), requesting a broad range of information regarding Boardman to determine whether the plant is in compliance with the Oregon State Implementation Plan, federal New Source Performance Standards and other CAA requirements. On March 20, 2009, the Company received a follow-up request for information relating to the generation, heat input, and emissions of the plant. The Company has responded to both requests. The EPA has not informed the Company of any violations or possible violations of the CAA with respect to Boardman and the Company is not aware of any such violations. As a result, the Company cannot predict the outcome of this matter.

The Company also faces legal challenges over past and current operating standards for the plant. For additional information, see "Sierra Club et al. v. Portland General Electric Company" in Item 3.—"Legal Proceedings."

Liquidity

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

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

	Years Ended December 31,		
	2009	**2008**	**2007**
Cash and cash equivalents, beginning of year	$ 10	$ 73	$ 12
Net cash provided by (used in):			
Operating activities	386	183	344
Investing activities	(700)	(382)	(451)
Financing activities	335	136	168
Net change in cash and cash equivalents	21	(63)	61
Cash and cash equivalents, end of year	$ 31	$ 10	$ 73

2009 Compared to 2008

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 $203 million increase in cash provided by operating activities in 2009 compared to 2008 was largely due to a decrease in margin deposit requirements pursuant to power and natural gas purchase agreements, driven primarily by increases in the forward market prices of power and natural gas, partially offset by customer refunds related to certain Trojan matters. The $60 million increase in the change of Deferred income taxes, a non-cash charge included in Net income, is related primarily to the Company's price risk management activities.

A significant portion of cash provided by operations consists of recovery in customer prices of non-cash charges for depreciation and amortization. The Company estimates that depreciation and amortization charges will approximate $225 million in 2010. Combined with all other sources, cash provided by operations is estimated to be approximately $526 million for 2010. This estimate includes the return of $6 million of margin deposits held by certain wholesale customers and brokers as of December 31, 2009, and is based on both the timing of contract settlements and projected energy prices. The remaining $295 million in estimated cash flows from operations in 2010 is expected from normal operating activities.

Cash Flows from Investing Activities—Cash flows used in investing activities consist primarily of capital expenditures related to new construction and improvements to PGE's distribution, transmission, and generation facilities. Capital expenditures increased $313 million in 2009 compared to 2008 due to increased construction costs related to Biglow Canyon Phases II and III and the smart meter project, partially offset by a decrease in construction costs related to the Selective Water Withdrawal project.

The Company plans $540 million of capital expenditures in 2010 related to Biglow Canyon Phase III, the smart meter project, hydro licensing and construction, and ongoing capital expenditures related to upgrades to and replacement of transmission, distribution and generation infrastructure. See "Capital Requirements" section above for additional information.

Cash Flows from Financing Activities—Financing activities provide supplemental cash for both day-to-day operations and capital requirements as needed. During 2009, net cash provided by financing activities primarily consisted of proceeds received from the issuance of long-term debt of $580 million and common stock for net proceeds of $170 million, partially offset by the net repayment of short-term debt of $203 million, the repayment of long-term debt of $142 million, and the payment of dividends of $72 million. Financing activities also included the receipt of $7 million in capital contributions from noncontrolling interests in two solar projects. During 2008, net cash provided by financing activities consisted of short-term borrowings of $203 million and the issuance of long-term debt of $49 million, net of issuance costs, partially offset by the repayment of long-term debt of $56 million and the payment of dividends of $60 million.

PGE currently expects to issue approximately $250 million of debt in 2010, of which $70 million was issued in January 2010.

2008 Compared to 2007

Cash Flows from Operating Activities—The $161 million decrease in cash provided by operating activities in 2008 compared to 2007 was primarily due to an increase in margin deposits required under power and natural gas purchase agreements, driven by a decrease in the forward market prices of power and natural gas, partially offset by an increase in cash received from retail electricity sales resulting from increased energy deliveries. The $27 million increase in non-cash charges for depreciation and amortization in 2008 from 2007 was primarily related to Port Westward and Biglow Canyon Phase I, which were placed in service in June and December 2007, respectively, as well as the accelerated depreciation of existing meters being replaced pursuant to the smart meter project.

Cash Flows from Investing Activities—Capital expenditures decreased $72 million in 2008 from 2007 primarily due to decreased construction costs related to Biglow Canyon Phase I, which was completed in December 2007, and Port Westward, which was completed in June 2007. The decrease was partially offset by increased construction costs related to Biglow Canyon Phases II and III, which began construction in the last half of 2008, and the Selective Water Withdrawal project, which began construction in late 2007.

Cash Flows from Financing Activities—During 2008, net cash provided by financing activities consisted of short-term borrowings of $203 million and the issuance of long-term debt of $49 million, net of issuance costs, partially offset by the repayment of long-term debt of $56 million and the payment of dividends of $60 million. During 2007, net cash provided by financing activities consisted of the issuance of long-term debt of $378 million, net of issuance costs, partially offset by the repayment of short-term borrowings of $81 million, the repayment of long-term debt of $71 million and the payment of dividends of $58 million.

Dividends on Common Stock

The following table indicates common stock dividends declared in 2009:

Declaration Date	Record Date	Payment Date	Declared Per Common Share
February 19, 2009	March 25, 2009	April 15, 2009	$0.245
May 13, 2009	June 25, 2009	July 15, 2009	0.255
August 5, 2009	September 25, 2009	October 15, 2009	0.255
October 28, 2009	December 28, 2009	January 15, 2010	0.255

While the Company expects to pay regular quarterly dividends on its common stock, 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 deem 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 17, 2010, the Board of Directors declared a dividend of $0.255 per share of common stock to stockholders of record on March 25, 2010, payable on or before April 15, 2010.

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

In January 2010, S&P lowered its ratings on PGE's senior secured debt from 'A' to 'A-' and senior unsecured debt from 'BBB+' to 'BBB'. S&P's ratings changes reflect their view of current weak economic conditions and concerns regarding PGE's "under-earning" of authorized returns. S&P also revised its outlook on the Company from 'negative' to 'stable' based on their expectation that credit metrics will not diminish and that PGE will maintain sufficient liquidity to absorb the impacts of a major outage and other events.

Should Moody's and/or S&P reduce their credit rating on PGE's unsecured debt to below investment grade, the Company could be subject to requests by certain of its wholesale, commodity and related transmission counterparties to post additional performance assurance collateral in connection with its price risk management activities. These deposits, which are classified as Margin deposits in PGE's consolidated balance sheet, are based on the contract terms and commodity prices and can vary from period to period. As of December 31, 2009, PGE had posted approximately $200 million of collateral with these counterparties, consisting of $56 million in cash and $144 million in letters of credit, $28 million of which is affiliated with master netting agreements. Provided that market prices remain unchanged, the Company anticipates that approximately 64% of the posted collateral would no longer be required by the end of 2010 as the related contracts are settled, with another 25% expected to roll off by the end of 2011. Based on the Company's energy portfolio, estimates of energy market prices, and the level of collateral outstanding as of December 31, 2009, the approximate amount of additional collateral that could be requested upon a single agency downgrade to below investment grade is approximately $86 million and decreases to approximately $35 million by December 31, 2010. The amount of additional collateral that could be requested upon a dual agency downgrade to below investment grade is approximately $150 million and decreases to approximately $72 million by December 31, 2010.

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.

The issuance of additional 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, under the most restrictive issuance test in the Indenture of Mortgage and Deed of Trust, the Company could have issued up to approximately $280 million of additional first mortgage bonds on December 31, 2009, of which $70 million was issued in January 2010. Any additional 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 on the basis of property additions, bond credits, and/or deposits of cash.

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, 2009, the Company's debt ratio, as calculated under the credit agreements, was 53.1%.

Debt and Equity Financings

PGE's ability to secure sufficient long-term capital at a reasonable cost is determined by its financial performance and outlook, capital expenditure requirements, alternatives available to investors, and other factors. The Company's ability to obtain and renew such financing depends on its credit ratings, as well as on credit markets, both generally and for electric utilities in particular. Management believes that the availability of credit facilities, the expected ability to issue long-term debt and equity securities, and cash expected to be generated from operations provide sufficient liquidity to meet the Company's anticipated capital and operating requirements. However, the Company's ability to issue long-term debt and equity could be adversely affected by changes in capital market conditions. PGE currently expects to issue approximately $250 million of debt in 2010, of which $70 million was issued on January 15, 2010.

Short-term Debt. PGE has approval from the FERC to issue short-term debt up to a total of $750 million through February 6, 2012 and currently has the following unsecured revolving credit facilities:

- A $370 million credit facility with a group of banks, with $10 million and $360 million scheduled to terminate in July 2012 and July 2013, respectively;
- A $200 million credit facility with a group of banks, which is scheduled to terminate in December 2012; and
- A $30 million credit facility with a bank, which is scheduled to terminate in June 2012.

These credit facilities supplement operating cash flows and provide a primary source of liquidity. Pursuant to the individual terms of the agreements, the credit facilities may be used for general corporate purposes and as a backup for commercial paper borrowings. The $370 million and $30 million credit facilities also permit the issuance of standby letters of credit. As of December 31, 2009, PGE had no borrowings or commercial paper outstanding and had $163 million of letters of credit outstanding under the credit facilities. As of December 31, 2009, the aggregate unused available credit under the credit facilities was $437 million.

Long-term Debt. In 2009, PGE issued the following first mortgage bonds:

- $130 million in January 2009 consisting of $67 million of 6.8% Series, which mature January 15, 2016, and $63 million of 6.5% Series, which mature January 15, 2014;
- $300 million of 6.1% Series in April 2009, which mature April 15, 2019; and
- $150 million of 5.43% Series in November 2009, which mature May 3, 2040.

On May 1, 2009, PGE purchased $142 million of its Pollution Control Bonds, which are now owned by the Company. These Pollution Control Bonds may be remarketed at a later date at PGE's option through 2033. As of December 31, 2009, total long-term debt outstanding was $1,744 million.

In January 2010, PGE issued $70 million of 3.46% Series First Mortgage Bonds which mature January 15, 2015.

Equity. In March 2009, PGE issued 12,477,500 shares of common stock. The net proceeds of $170 million were used to repay outstanding short-term debt, fund capital expenditures, and for general corporate purposes.

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 46.9% and 47.3% as of December 31, 2009 and 2008, respectively.

Contractual Obligations and Commercial Commitments

The following indicates PGE's contractual obligations as of December 31, 2009 (in millions):

	Payments Due						
	2010	2011	2012	2013	2014	There-after	Total
Long-term debt	$ 186	$—	$100	$100	$ 73	$1,285	$1,744
Interest on long-term debt (1)	97	94	93	86	79	1,159	1,608
Capital and other purchase commitments	315	36	7	8	1	18	385
Purchased power and fuel:							
Electricity purchases	324	89	65	66	63	521	1,128
Capacity contracts	22	21	20	20	20	38	141
Public Utility Districts	7	7	5	5	5	34	63
Natural gas	97	36	17	16	13	29	208
Coal and transportation	20	17	3	3	—	—	43
Pension plan contributions (2)	—	19	18	16	6	1	60
Operating leases	8	9	9	10	10	234	280
Total	$1,076	$328	$337	$330	$270	$3,319	$5,660

(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, 2009.

(2) Contributions to the Company's pension plan are estimated based on numerous plan assumptions, including plan funded status. For plan year 2010, a discount rate of 6.63% was used and for plan years 2011 through 2015, a discount rate of 6.5% and return on plan assets of 8.5% were used. Contributions in 2015 are estimated to be $1 million. Contributions beyond 2015 have not been estimated.

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 four hydroelectric projects (the Rocky Reach, 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 Rocky Reach and Wells projects, 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 that have, or are likely to have, a material current or future effect on its consolidated financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Critical Accounting Policies

The preparation of the 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 consolidated financial 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

PGE is a rate-regulated enterprise and applies regulatory accounting, which results in regulatory assets or regulatory liabilities on its consolidated balance sheets. Regulatory assets represent probable future revenue associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited or refunded to customers through the ratemaking process. Regulatory accounting is appropriate as long as rates are established by or subject to approval by independent third-party regulators; rates are designed to recover the specific enterprise's cost of service; and in view of demand for service, it is reasonable to assume that rates set at levels that will recover costs can be charged to and collected from customers. Once the regulatory asset or liability is reflected in prices, the respective regulatory asset or liability is amortized to the appropriate line item in the statement of income over the period in which it is included in prices.

If future recovery of costs ceases to be probable, however, PGE would be required to write off its regulatory assets. In addition, 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 could 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. 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 statement of income, with those related to other property included in Other income (expense), net. Accretion of the ARO liability is classified as an operating expense in the consolidated statement 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 revenue is billed monthly and is based on meter readings taken throughout the month. At the end of each reporting period, PGE estimates the revenue earned from the last meter read date through the last day of the month, which has not been billed as of the last day of the month. Such amount is classified as Unbilled revenues in the Company's consolidated balance sheets. Unbilled revenues is calculated based on each month's actual net retail system load, the number of days from the last meter read date through the last day of the month, and current retail customer prices.

Contingencies

The Company has unresolved legal and regulatory issues for which there is inherent uncertainty with respect to the ultimate outcome of the respective matter. Contingencies are evaluated using the best information available. A material loss contingency is accrued and disclosed when it is probable that an asset has been impaired or a liability incurred and the amount of the loss can be reasonably estimated. If a range of probable loss is established, the minimum amount in the range is accrued, unless some other amount within the range appears to be a better estimate. If the probable loss cannot be reasonably estimated, no accrual is recorded, but the loss contingency is disclosed to the effect that it cannot be reasonably estimated. Material loss contingencies are disclosed when it is reasonably possible that an asset has been impaired or a liability incurred. Established accruals reflect management's assessment of inherent risks, credit worthiness, and complexities involved in the process. No assurance can be given for the ultimate outcome of any particular contingency.

Price Risk Management

PGE engages in price risk management activities to minimize net variable power costs for retail customers. PGE utilizes financial instruments such as electricity forward, swap, and option contracts and natural gas forward, swap, option, and futures contracts to protect the Company against variability in expected future cash flows due to associated price risk. These financial instruments are recorded at fair value, or "mark-to-market", in PGE's consolidated financial statements.

Marking a contract to market consists of reevaluating the market value at the end of each reporting period for the entire term of the contract and recording any change in value (difference between the contract price and current market price) in either net income or other comprehensive income for the period. Valuation of these financial instruments reflects management's best estimates of market prices, including closing New York Mercantile Exchange (NYMEX) and over-the-counter quotations, time value of money, and volatility factors underlying the commitments.

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 price 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, NYMEX, and other sources, and are validated using independent publications. Estimates used in creating forward price curves can change with market conditions and can be materially affected by unpredictable factors such as weather and the economy. The difference between PGE's forward price curves and four independently published price curves averages 1%. The difference at any single location, delivery date and commodity is less than 5%.

For purchases and sales of forward physical or financial contracts, the mark-to-market value is the present value of the difference between PGE's contracted price and the forward price multiplied by the total quantity of the contract. For option contracts, a theoretical value is computed using standard financial models that utilize price volatility, price correlation, time to expiration, interest rate and price curves. The mark-to-market of these options includes the premium paid or received as a component of the theoretical value.

Pension Plan

Pension expense is dependent on several assumptions used in the actuarial valuation of the plan. Primary assumptions 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 based on assumptions regarding rates of return on long-term high quality bonds. Assumptions regarding the expected rate of return on plan assets are based on historical and projected average rates of return for current asset classes in the plan investment portfolio. The expected rate of return reflects expected future returns for the portfolio, and was used in determining net periodic pension expense for the year.

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 would have increased 2009 net periodic pension expense by approximately $1.2 million. A 0.25% reduction in the discount rate would have increased 2009 net periodic pension expense by approximately $1.5 million.

Fair Value Measurements

In accordance with accounting and reporting requirements, PGE applies fair value measurements to its financial assets and liabilities. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The Company's financial assets and liabilities consist of derivative instruments, money market funds and fixed income securities held by the Nuclear decommissioning 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 market 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, which provides quarterly reports to the Audit Committee of PGE's Board of Directors, 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 recommends for adoption policies and procedures, establishes risk limits subject to PGE Board approval, and monitors compliance with policies, procedures, and limits on a regular basis through reports and meetings.

Commodity Price Risk

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

PGE actively manages its risk to ensure compliance with its risk management policies. The Company monitors open commodity positions in its energy portfolio that extend over the next 24 months using a value at risk methodology, which measures the potential impact of market movements over a one-day holding period using a variance/covariance approach at a 95% confidence interval. The portfolio is modeled using net open power and natural gas positions, with power averaged over peak and off-peak periods by month, and includes all financial and physical positions for the next 24 months, including estimates of retail load and plant generation. The risk factors include commodity prices for power and natural gas at various locations and do not include volumetric variability. Based on this methodology, the average, high, and low value at risk on the Company's energy portfolio in 2009 were $2.7 million, $5.1 million, and $1.2 million, respectively, and in 2008 were $4.8 million, $7.0 million, and $2.2 million, respectively. PGE's value at risk measurement is performed prior to the effects of regulation as discussed below.

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 margining requirements based on the value of open positions and regulatory risk if recovery is disallowed by the OPUC. PGE mitigates 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, 2009, a 10% change in the value of the Canadian dollar would result in an immaterial change in income before income taxes for transactions that will settle over the next 12 months.

Interest Rate Risk

To meet short-term cash requirements, PGE has established a program under which it may from time to time issue commercial paper for terms of up to 270 days; such issuances are supported by the Company's unsecured revolving credit facilities. Although any borrowings under the commercial paper program subject the Company to fluctuations in interest rates, reflecting current market conditions, individual instruments carry a fixed rate during their respective terms. As of December 31, 2009, PGE had no borrowings or outstanding commercial paper.

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, 2009, the total fair value and carrying amounts by maturity date of PGE's long-term debt are as follows (in millions):

	Total Fair Value	Carrying Amounts by Maturity Date						
		Total	2010	2011	2012	2013	2014	There-after
First Mortgage Bonds	$1,622	$1,548	$—	$—	$100	$100	$ 63	$1,285
Pollution Control Revenue Bonds	47	47	37	—	—	—	10	—
7.875% unsecured notes	149	149	149	—	—	—	—	—
Total	$1,818	$1,744	$186	$—	$100	$100	$ 73	$1,285

As of December 31, 2009, PGE had no long-term variable rate debt outstanding. Therefore, the Company's outstanding long-term debt is not subject to interest rate risk exposures.

Credit Risk

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

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

As of December 31, 2009, PGE's credit risk exposure is $30 million for commodity activities with externally—rated investment grade counterparties and matures as follows: $2 million in 2010; $5 million in 2011 and 2012; and $6 million in 2013, 2014 and thereafter. 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 Notes to Consolidated Financial Statements in Item 8.—"Financial Statements and Supplementary Data." Management believes that circumstances that could result in the nonperformance by these counterparties are remote.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

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

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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, 2009 and 2008, and the related consolidated statements of income, equity, comprehensive income, and cash flows for each of the three years in the period ended December 31, 2009. We also have audited the Company's internal control over financial reporting as of December 31, 2009, 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 Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting based on our audits.

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

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

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Portland General Electric Company and subsidiaries as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009, 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, 2009, 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 24, 2010

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME
(Dollars in millions, except per share amounts)

Years Ended December 31,	2009	2008	2007
Revenues, net	$ 1,804	$ 1,745	$ 1,743
Operating expenses:			
Purchased power and fuel	944	878	879
Production and distribution	178	169	150
Administrative and other	179	190	184
Depreciation and amortization	211	208	181
Taxes other than income taxes	84	83	80
Total operating expenses	1,596	1,528	1,474
Income from operations	208	217	269
Other income (expense):			
Allowance for equity funds used during construction	18	9	16
Miscellaneous income (expense), net	3	(14)	8
Other income (expense), net	21	(5)	24
Interest expense	104	90	74
Income before income taxes	125	122	219
Income taxes	36	35	74
Net income	89	87	145
Less: net loss attributable to noncontrolling interests	(6)	—	—
Net income attributable to Portland General Electric Company	$ 95	$ 87	$ 145
Weighted-average shares outstanding (in thousands):			
Basic	72,790	62,544	62,512
Diluted	72,852	62,581	62,534
Earnings per share—basic and diluted	$ 1.31	$ 1.39	$ 2.33
Dividends declared per common share	$ 1.01	$ 0.97	$ 0.93

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(In millions)

As of December 31,	2009	2008
ASSETS		
Current assets:		
Cash and cash equivalents	$ 31	$ 10
Accounts receivable, net	159	168
Unbilled revenues	95	96
Inventories, at average cost:		
Materials and supplies	34	36
Fuel	24	35
Margin deposits	56	189
Regulatory assets—current	197	194
Other current assets	94	92
Total current assets	690	820
Electric utility plant:		
Production	2,269	1,943
Transmission	364	351
Distribution	2,472	2,307
General	277	259
Intangible	214	206
Construction work in progress	406	284
Total electric utility plant	6,002	5,350
Accumulated depreciation and amortization	(2,144)	(2,049)
Electric utility plant, net	3,858	3,301
Regulatory assets—noncurrent	465	631
Nuclear decommissioning trust	50	46
Non-qualified benefit plan trust	47	46
Other noncurrent assets	62	45
Total assets	$ 5,172	$ 4,889

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS, continued
(In millions, except share amounts)

As of December 31,	2009	2008
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 187	$ 217
Liabilities from price risk management activities—current	128	225
Short-term debt	—	203
Current portion of long-term debt	186	142
Regulatory liabilities—current	27	43
Other current liabilities	92	59
Total current liabilities	620	889
Long-term debt, net of current portion	1,558	1,164
Regulatory liabilities—noncurrent	654	640
Deferred income taxes	356	304
Unfunded status of pension and postretirement plans	143	174
Liabilities from price risk management activities—noncurrent	127	201
Non-qualified benefit plan liabilities	96	91
Other noncurrent liabilities	75	72
Total liabilities	3,629	3,535
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 as of December 31, 2009 and 2008	—	—
Common stock, no par value, 160,000,000 shares authorized; 75,210,580 and 62,575,257 shares issued and outstanding as of December 31, 2009 and 2008, respectively	829	659
Accumulated other comprehensive loss	(6)	(5)
Retained earnings	719	700
Total Portland General Electric Company shareholders' equity	1,542	1,354
Noncontrolling interests' equity	1	—
Total equity	1,543	1,354
Total liabilities and equity	$5,172	$4,889

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF EQUITY
(Dollars in millions)

	Portland General Electric Company Shareholders' Equity				
	Common Stock		Accumulated Other Comprehensive Loss	Retained Earnings	Noncontrolling Interests' Equity
	Shares	Amount			
Balances as of December 31, 2006	62,504,767	$643	$ (6)	$587	$—
Vesting of restricted stock units	16,841	—	—	—	—
Shares issued pursuant to employee stock purchase plan	8,179	—	—	—	—
Stock-based compensation	—	3	—	—	—
Dividends declared	—	—	—	(58)	—
Net income	—	—	—	145	—
Other comprehensive income	—	—	2	—	—
Balances as of December 31, 2007	62,529,787	646	(4)	674	—
Vesting of restricted stock units	19,884	—	—	—	—
Shares issued pursuant to employee stock purchase plan	25,586	1	—	—	—
Former parent capital contribution	—	8	—	—	—
Stock-based compensation	—	4	—	—	—
Dividends declared	—	—	—	(61)	—
Net income	—	—	—	87	—
Other comprehensive loss	—	—	(1)	—	—
Balances as of December 31, 2008	62,575,257	659	(5)	700	—
Issuance of common stock, net of issuance costs of $6	12,477,500	170	—	—	—
Vesting of restricted and performance stock units	128,175	—	—	—	—
Shares issued pursuant to employee stock purchase plan	29,648	—	—	—	—
Noncontrolling interests' capital contributions	—	—	—	—	7
Stock-based compensation	—	—	—	—	—
Dividends declared	—	—	—	(76)	—
Net income (loss)	—	—	—	95	(6)
Other comprehensive loss	—	—	(1)	—	—
Balances as of December 31, 2009	75,210,580	$829	$ (6)	$719	$ 1

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions)

Years Ended December 31,	**2009**	**2008**	**2007**
Net income	$ 89	$ 87	$145
Other comprehensive income (loss) items, net of taxes:			
Pension and other postretirement plans' funded position, net of taxes of $(14) in 2009, $69 in 2008 and $(12) in 2007	21	(108)	20
Reclassification of defined benefit pension plan and other benefits to regulatory (asset) liability, net of taxes of $14 in 2009, $(69) in 2008 and $12 in 2007	(22)	107	(18)
Gains (losses) on cash flow hedges:			
Unrealized holding losses, net of taxes of $2 in 2007	—	—	(2)
Reclassification to net income for contract settlements, net of taxes of $(1) in 2008 and $(1) in 2007	—	2	2
Reclassification of net realized and unrealized gains to regulatory liabilities, net of taxes of $1 in 2008 and $(1) in 2007	—	(2)	—
Total gains on cash flow hedges	—	—	—
Total other comprehensive income (loss) items, net of taxes	(1)	(1)	2
Comprehensive income	88	86	147
Less: comprehensive loss attributable to the noncontrolling interests	(6)	—	—
Comprehensive income attributable to Portland General Electric Company	$ 94	$ 86	$147

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

Years Ended December 31,	2009	2008	2007
Cash flows from operating activities:			
Net income	$ 89	$ 87	$ 145
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	211	208	181
Increase (decrease) in net liabilities from price risk management activities	(145)	350	(26)
Regulatory deferrals—price risk management activities	145	(350)	26
Deferred income taxes	82	22	22
Trojan refund liability	—	34	—
Allowance for equity funds used during construction	(18)	(9)	(16)
Power cost deferrals, net	(18)	2	(9)
(Gains) losses on non-qualified benefit plan trust assets	(8)	17	(5)
Senate Bill 408 deferrals, net of amortization	—	(1)	(16)
Other non-cash income and expenses, net	8	—	6
Changes in working capital:			
(Increase) decrease in margin deposits	133	(163)	21
(Increase) decrease in receivables	11	6	(4)
Increase (decrease) in payables	(16)	(11)	19
Other working capital items, net	(51)	(8)	(2)
Distribution of Trojan refund liability	(34)	—	—
Other, net	(3)	(1)	2
Net cash provided by operating activities	386	183	344
Cash flows from investing activities:			
Capital expenditures	(696)	(383)	(455)
Sales of nuclear decommissioning trust securities	36	23	21
Purchases of nuclear decommissioning trust securities	(36)	(19)	(23)
Insurance proceeds	—	3	—
Other, net	(4)	(6)	6
Net cash used in investing activities	(700)	(382)	(451)

See accompanying notes to consolidated financial statements.

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS, continued
(In millions)

Years Ended December 31,	2009	2008	2007
Cash flows from financing activities:			
Proceeds from issuance of long-term debt	$ 580	$ 50	$381
Proceeds from issuance of common stock, net of issuance costs	170	—	—
Payments on long-term debt	(142)	(56)	(71)
Borrowings on revolving lines of credit	82	189	—
Payments on revolving lines of credit	(213)	(58)	—
(Payments) borrowings on short-term debt, net	(72)	72	(81)
Dividends paid	(72)	(60)	(58)
Debt issuance costs	(5)	(1)	(3)
Noncontrolling interests' capital contribution	7	—	—
Net cash provided by financing activities	335	136	168
Change in cash and cash equivalents	21	(63)	61
Cash and cash equivalents, beginning of year	10	73	12
Cash and cash equivalents, end of year	$ 31	$ 10	$ 73
Supplemental disclosures of cash flow information:			
Cash paid during the year for:			
Interest, net of amounts capitalized	$ 74	$ 73	$ 58
Income taxes	2	20	46
Non-cash investing and financing activities:			
Accrued capital additions	17	16	27
Accrued dividends payable	20	16	15
Former parent's capital contribution of Oregon Tax credits	—	8	—

See accompanying notes to consolidated financial statements.

NOTE 1: BASIS OF PRESENTATION

Nature of Operations

Portland General Electric Company (PGE or the Company) is a single, vertically integrated electric utility engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the state of Oregon. The Company also sells electricity and natural gas in the wholesale market to utilities, brokers, and power marketers. PGE operates as a single segment, with revenues and costs related to its business activities maintained and analyzed on a total electric operations basis. PGE's corporate headquarters is located in Portland, Oregon and its service area is located entirely within Oregon. PGE's service area includes 52 incorporated cities, of which Portland and Salem are the largest, within a state-approved service area allocation of approximately 4,000 square miles. As of December 31, 2009, PGE served 815,739 retail customers with a service area population of approximately 1.7 million, comprising 43% of the state's population.

As of December 31, 2009, PGE had 2,708 employees, with 890 employees covered under agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers (Local 125). Such agreements cover 856 and 34 employees and expire on February 28, 2012 and August 1, 2011, respectively.

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

Consolidation Principles

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

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

Use of Estimates

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

PGE considered events through February 24, 2010, for purposes of determining whether any event warranted recognition or disclosure in its annual consolidated financial statements as of and for the year ended December 31, 2009.

Reclassifications

During the first quarter of 2009, PGE reconsidered the presentation of its Assets and Liabilities from price risk management activities, which previously had all been classified as current, as well as its Regulatory assets and liabilities, which previously had all been classified as noncurrent. The Company determined it was preferable to present such assets and liabilities as either current or noncurrent based on the expected settlement dates of the underlying contracts for price risk management activities and the timing of amortization or the timing of the collection or refund of the respective Regulatory asset or liability. To conform to the 2009 presentation, certain reclassifications have been made to the December 31, 2008 consolidated balance sheet. These reclassifications include the presentation of noncurrent Assets from price risk management activities of $8 million (included in Other noncurrent assets) and noncurrent Liabilities from price risk management activities of $201 million, all of which were previously classified as current, and a current portion of Regulatory assets of $194 million and a current portion of Regulatory liabilities of $43 million, all of which were previously classified as noncurrent. Deferred taxes associated with these Assets and Liabilities from price risk management activities and Regulatory assets and liabilities were also reclassified to current or noncurrent, as appropriate. As a result of the preceding reclassifications, current deferred income tax assets of $134 million have been reclassified to noncurrent Deferred income tax liabilities as of December 31, 2008 to conform to the 2009 presentation.

NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Cash and Cash Equivalents

Highly liquid investments with maturities of three months or less at the date of acquisition are classified as cash equivalents. Cash equivalents consist of money market funds, of which PGE had $18 million as of December 31, 2009 and none as of December 31, 2008.

Accounts Receivable

Accounts receivable are recorded at invoiced amount and do not bear interest when recorded. A late fee of 1.5% may be assessed on residential account balances after 60 days and on nonresidential balances after 30 days. An account balance is charged-off after efforts have been made to collect such amount, but no sooner than 45 days after the final due date.

Estimated provisions for uncollectible accounts receivable related to retail sales, charged to Administrative and other expense, are recorded in the same period as the related revenues, with an offsetting credit to the allowance for uncollectible accounts. Such estimates are based on management’s assessment of the probability of collection of customer accounts, aging of accounts receivable, bad debt write-offs, actual customer billings, and other factors.

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

Price Risk Management

PGE engages in price risk management activities, utilizing financial instruments such as forward, swap, and option contracts for electricity and natural gas, and futures contracts for natural gas. These instruments are measured at fair value and recorded on the consolidated balance sheets as assets or liabilities from price risk management activities, unless they qualify for the normal purchases and normal sales exception. Changes in fair value are recognized in the statement of income unless hedge accounting applies, offset by the effects of regulatory accounting.

Certain electricity forward contracts that were entered into in anticipation of serving the Company's regulated retail load meet the requirements for treatment under the normal purchases and normal sales exception. Other activities consist of certain electricity forwards, options and swaps, certain natural gas forwards, options, and swaps, and forward contracts for acquiring Canadian dollars. Such activities are utilized as economic hedges to protect against variability in expected future cash flows due to associated price risk and to minimize net power costs for retail customers.

The OPUC recognizes derivative contracts only at the time of settlement. Contracts that qualify for the normal purchases and normal sales exception are not required to be recorded at fair value. Unrealized gains and losses from contracts that qualify as cash flow hedges are recorded net in other comprehensive income and contracts not designated as cash flow hedges are recorded net in Purchased power and fuel expense on the statements of income. The timing difference between the recognition of unrealized gains and losses on derivative instruments and their realization and subsequent recovery in rates is recorded as a regulatory asset or regulatory liability to reflect the effects of regulatory accounting.

Electricity sales and purchases that are physically settled are recorded in Revenues and Purchased power and fuel expense upon settlement, respectively. Electricity sales and purchases resulting from derivative activities that are not physically settled are recorded on a net basis in Purchased power and fuel expense.

Pursuant to transactions entered into in connection with PGE's price risk management activities, the Company may be required to provide deposits with certain counterparties. These deposits are based on the contract terms and commodity prices and can vary period to period. These deposits are classified as Margin deposits in the accompanying consolidated balance sheets and were $56 million and $189 million as of December 31, 2009 and 2008, respectively.

Inventories

PGE's inventories, recorded at average cost, consist primarily of materials and supplies for use in operations, maintenance and capital activities and fuel for use in generating plants. Fuel inventories include natural gas, oil, and coal. Natural gas inventory is valued at the lower of average cost or market. Oil and coal inventories are valued at average cost as they are recovered at average cost when utilized.

Property, Plant and Equipment

Capitalization Policy

Electric utility plant is capitalized at its original cost. Costs include direct labor, materials and supplies, and contractor costs, as well as indirect costs such as engineering, supervision, employee benefits, and allowance for funds used during construction (AFDC). Plant replacements are capitalized, with minor items charged to expense as incurred. Costs to purchase or develop software applications for internal use only are capitalized and amortized over the estimated useful life of the software. Costs of obtaining a FERC license for the Company's hydroelectric projects are capitalized and amortized over the related license period.

Costs which are disallowed for recovery in rates are charged to expense at the time such disallowance is probable. Pursuant to a stipulation entered into with the OPUC and other interested parties in January 2010, PGE agreed to forego the recovery of certain capital costs incurred in connection with a delay in the completion of the Selective Water Withdrawal project, and pursue recovery of these costs through insurance and from firms involved in the design, construction and installation of the project. Accordingly, during the fourth quarter of 2009, PGE charged to expense approximately $6 million of costs related to the Selective Water Withdrawal project. Such amount is included in Production and distribution expense in the consolidated statement of income for the year ended December 31, 2009.

PGE records AFDC, which represents the pre-tax cost of borrowed funds used for construction purposes and the rate granted in the latest rate proceeding for equity funds. AFDC is capitalized as part of the cost of plant and credited to the statement of income. The average rate used by PGE was 7% in 2009, 8% in 2008 and 2007. AFDC from borrowed funds was $12 million in 2009, $6 million in 2008, and $10 million in 2007 and is reflected in the consolidated statements of income as a reduction to interest expense. AFDC from equity funds was $18 million in 2009, $9 million in 2008 and $16 million in 2007 and is reflected as a component of Other income (expense), net.

Costs of periodic major maintenance inspections and overhauls at the Company's generating plants are charged to operating expense as incurred.

Depreciation and Amortization

Depreciation is computed using the straight-line method, based upon original cost, and includes an estimate for cost of removal and expected salvage. Depreciation expense as a percent of the related average depreciable plant in service was approximately 3.8% in 2009, 3.7% in 2008, and 3.9% in 2007. Estimated asset retirement removal costs included in depreciation expense were $47 million, $47 million, and $43 million for the years ended December 31, 2009, 2008, and 2007, respectively.

Periodic studies are conducted to update depreciation parameters (i.e. retirement dispersion patterns, average service lives, and net salvage rates), including estimates of asset retirement obligations (AROs) and asset retirement removal costs. The studies are conducted every five years and are filed with the OPUC for approval and inclusion in a future rate proceeding. On November 18, 2009, PGE filed its most recent depreciation study with the OPUC.

Thermal production plants are depreciated using a life-span methodology which ensures that plant investment is recovered by the forecasted retirement date, which range from 2020 to 2042. Depreciation is provided on the Company's other classes of plant in service over their estimated average service lives, which are as follows:

Production, excluding thermal:	
Hydro	88 years
Wind	27 years
Transmission	48 years
Distribution	30 years
General	13 years

The original cost of depreciable property units, net of any related salvage value, is charged to accumulated depreciation when property is retired and removed from service. Cost of removal expenditures are charged to AROs for assets that meet the definition of a legal obligation and to accumulated asset retirement removal costs, included in Regulatory liabilities, for assets without AROs.

Intangible plant consists primarily of computer software development costs, which are amortized over either five or ten years, and hydro licensing costs, which are amortized over the applicable license term, which range from 30 to 50 years. Amortization expense was $16 million in 2009, $14 million in 2008, and $15 million in 2007. Accumulated amortization was $122 million and $109 million as of December 31, 2009 and 2008, respectively. Future estimated amortization expense as of December 31, 2009 is as follows: $16 million in 2010, $13 million in 2011, $11 million in 2012, $5 million in 2013, and $2 million in 2014.

Marketable Securities

All of PGE's investments in marketable securities, included in the Non-qualified benefit plan trust and Nuclear decommissioning trust on the consolidated balance sheets, are classified as trading. Trading securities are stated at fair value based on quoted market prices. Realized and unrealized gains and losses on the Non-qualified benefit plan trust assets are included in Other income (expense), net. Realized and unrealized gains and losses on the Nuclear decommissioning trust fund assets are recorded as regulatory liabilities or assets, respectively, as PGE expects to recover costs for these activities through rates. The cost of securities sold is based on the average cost method.

Regulatory Accounting

Regulatory Assets and Liabilities

As a rate-regulated enterprise, the Company applies regulatory accounting, resulting in regulatory assets or regulatory liabilities. Regulatory assets represent probable future revenue associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenue associated with amounts that are expected to be credited to customers through the ratemaking process. Regulatory accounting is appropriate as long as rates are established by or subject to approval by independent third-party regulators; rates are designed to recover the specific enterprise's cost of service; and in view of demand for service, it is reasonable to assume that rates set at levels that will recover costs can be charged to and collected from customers. Once the regulatory asset or liability is reflected in rates, the respective regulatory asset or liability is amortized to the appropriate line item in the statement of income over the period in which it is included in rates.

Circumstances that could result in the discontinuance of regulatory accounting include (1) increased competition that restricts the Company's ability to establish prices to recover specific costs, and (2) a significant change in the manner in which rates are set by regulators from cost-based regulation to another form of regulation. PGE periodically reviews the criteria of regulatory accounting to ensure that its continued application is appropriate. Based on a current evaluation of the various factors and conditions that are expected to impact future cost recovery, management believes that the Company's regulatory assets are probable of future recovery.

See Note 6 for additional information concerning the Company's regulatory assets and liabilities.

Power Cost Adjustment Mechanism

PGE is subject to a power cost adjustment mechanism (PCAM) as approved by the OPUC. Pursuant to the PCAM, the Company can adjust future prices to reflect a portion of the difference between each year's forecasted NVPC included in prices (baseline) and actual NVPC. PGE is subject to a portion of the business risk or benefit associated with the difference between actual NVPC and that included in base prices by application of an asymmetrical deadband within which PGE absorbs cost increases or decreases, with a 90/10 sharing of costs and benefits between customers and the Company, respectively, outside of the deadband. Any customer refund or collection is also subject to a regulated earnings test. A refund will occur only to the extent that it results in PGE's actual 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 ROE for that year being no greater than 1% below the Company's last authorized ROE. PGE's authorized ROE was 10.0% for 2009 and 10.1% for 2008. A final determination of any customer refund or collection is made by the OPUC through an annual public filing and review.

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

For 2009, the deadband ranged from $15 million below, to $29 million above, the baseline. Although PGE's actual NVPC as determined pursuant to the PCAM for 2009 exceeded the baseline by $22 million, it was within the established deadband and, accordingly, no customer collection was recorded in 2009. A final determination regarding the 2009 PCAM results will be made by the OPUC through a public filing and review in 2010.

For 2008, the deadband ranged from $14 million below, to $28 million above, the baseline. PGE's actual NVPC as determined under the PCAM for 2008 was less than the established baseline by approximately $31 million. No regulatory liability was recorded in 2008 for this amount however, as PGE's earnings did not attain the level required under the PCAM's regulated earnings test.

Asset Retirement Obligations

The fair value of a liability for an ARO is recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. PGE recognizes those legal obligations related to dismantlement and restoration costs associated with the future retirement of tangible long-lived assets. Because of the long lead time involved until future decommissioning activities occur, the Company uses present value techniques as quoted market prices and a market-risk premium are not available. The present value of estimated future removal expenditures is capitalized as an ARO on the consolidated balance sheets and revised periodically, with actual expenditures charged to the ARO as incurred.

The estimated capitalized costs of AROs are depreciated over the estimated life of the related asset, which is included in Depreciation and amortization for electric utility plant and Other income (expense), net for non-utility property in the consolidated statements of income.

Contingencies

Contingencies are evaluated using the best information available at the time the consolidated financial statements are prepared. A material loss contingency is accrued and disclosed when it is probable that an asset has been impaired or a liability incurred and the amount of the loss can be reasonably estimated. If a range of possible 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 the probable loss cannot be reasonably estimated. A material loss contingency will be disclosed when it is reasonably possible that an asset has been impaired or a liability incurred. Gain contingencies are recognized when realized and are disclosed when material. Legal costs incurred in connection with loss contingencies are expensed as incurred.

Accumulated Other Comprehensive Loss

Accumulated other comprehensive loss (AOCL) is comprised of the difference between the pension and other postretirement plans' obligations recognized in net income to date, and the unfunded position as of December 31, 2009 and 2008.

Revenue Recognition

Revenues are recognized as electricity is delivered to customers and include amounts for any services provided. The rates charged to customers are subject to federal (FERC), and state (OPUC) regulation. Franchise taxes, which are collected from customers and remitted to taxing authorities, are recorded on a gross basis in PGE's consolidated statements of income. Amounts collected from customers are included in Revenues, net and amounts due to taxing authorities are included in Taxes other than income taxes and totaled $38 million in 2009, $36 million in 2008, and $35 million in 2007.

Retail revenue is billed monthly based on meter readings taken throughout the month. Unbilled revenue represents the revenue earned from the last meter read date through the last day of the month, which has not been billed as of the last day of the month. Unbilled revenue is calculated based on each month's actual net retail system load, the number of days from the last meter read date through the last day of the month, and current retail customer prices.

As a rate-regulated utility, there are situations in which PGE defers the recognition of certain revenues until the period in which the related costs are incurred or approved by the OPUC for amortization. For additional information, see *Regulatory Assets and Liabilities* in this Note 2.

Stock-Based Compensation

The measurement and recognition of compensation expense for all share-based payment awards, including restricted stock units, is based on the estimated fair value of the awards. The fair value of the portion of the award that is ultimately expected to vest is recognized as expense over the requisite service period. PGE attributes the value of stock-based compensation to expense on a straight-line basis.

Income Taxes

Income taxes are accounted for under the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between financial statement carrying amounts and tax bases of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in current and future periods that includes the enactment date. Any valuation allowance is established to reduce deferred tax assets to the "more likely than not" amount expected to be realized in future tax returns.

As a rate-regulated enterprise, changes in deferred tax assets and liabilities that are related to certain property are required to be passed on to customers through future rates and are charged or credited directly to a regulatory asset or regulatory liability. These amounts were recognized as net regulatory assets of $91 million and $88 million as of December 31, 2009 and 2008, respectively, and will be included in rates when the temporary differences reverse.

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

Uncertain tax positions represent management's expected treatment of a tax position taken in a filed tax return, or planned to be taken in a future tax return, that has not been reflected in measuring income tax expense for financial reporting purposes. Until such positions are sustained by the taxing authorities, PGE would not recognize the tax benefits resulting from such positions and would report the tax effect as a liability in the Company's consolidated balance sheet. As of December 31, 2009, PGE had no material uncertain tax positions.

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

New Accounting Standards

Adopted Accounting Pronouncements

On September 30, 2009, PGE adopted Statement of Financial Accounting Standards No. (SFAS) 168, *The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles—a replacement of FASB Statement No. 162* (SFAS 168). SFAS 168 modifies the U.S. generally accepted accounting principles (GAAP) hierarchy created by SFAS 162 by establishing only two levels of GAAP: authoritative and nonauthoritative. SFAS 168, which was codified within ASC 105, *Generally Accepted Accounting Principles*, establishes the *FASB Accounting Standards Codification* (ASC or Codification) as the single source of authoritative U.S. accounting and reporting standards, except for rules and interpretive releases of the SEC under authority of the federal securities laws, which are sources of authoritative GAAP for SEC registrants. All existing accounting standard documents are superseded and all other accounting literature not included in the Codification is considered nonauthoritative. Accordingly, the Codification is referenced as the sole source of authoritative literature. As the Codification does not change current GAAP, the adoption of SFAS 168 had no material impact on the Company's consolidated financial position, consolidated results of operation, or consolidated cash flows.

On January 1, 2009, PGE adopted SFAS 160, *Noncontrolling Interests in Consolidated Financial Statements—an amendment of ARB No 51* (SFAS 160), which establishes accounting and reporting standards for the noncontrolling interest in a subsidiary, as well as the deconsolidation of a subsidiary. SFAS 160 clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the deconsolidated entity that should be reported as equity in the consolidated financial statements. It also (1) changes the way the consolidated income statement is presented by requiring consolidated net income to be reported at amounts that include the amounts attributable to both the parent and the noncontrolling interest, (2) establishes a single method of accounting for changes in a parent's ownership interest in a subsidiary that do not result in deconsolidation, and (3) continues to allocate to a noncontrolling interest its share of losses if ever that attribution results in a deficit noncontrolling interest balance. SFAS 160 is to be applied prospectively, with the exception of the presentation and disclosure requirements, which are to be applied retrospectively for all periods presented. Beginning January 1, 2009, any noncontrolling interests resulting from the consolidation of a less-than-wholly-owned subsidiary are accounted for in accordance with SFAS 160. The adoption of SFAS 160, which was codified within ASC 810, *Consolidation*, upon the adoption of SFAS 168, did not have a material impact on PGE's consolidated financial position or consolidated results of operation. However, it did have an impact on the presentation of noncontrolling interests, formerly known as "minority interests", in PGE's consolidated financial position, consolidated results of operation, and consolidated cash flows.

On December 31, 2009, PGE adopted FSP FAS 132(R)-1, *Employers' Disclosures about Postretirement Benefit Plan Assets* (FSP FAS 132(R)-1), which requires enhanced annual disclosures about plan assets of an employer's defined benefit pension or other postretirement plans. Upon initial application, the provisions of this FSP are not required for earlier periods presented for comparative purposes. The adoption of FSP FAS 132(R)-1, which was codified within ASC 715, *Compensation—Retirement Benefits*, upon the adoption of SFAS 168, did not have a material impact on PGE's consolidated financial position, consolidated results of operation, or consolidated cash flows.

On December 31, 2009, PGE adopted ASU 2009-12, *Fair Value Measurements and Disclosures (Topic 820)—Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)* (ASU 2009-12). This Update provides additional guidance related to measuring the fair value of certain alternative investments and permits, in certain situations, a reporting entity to use the net asset value per share as a practical expedient to measure the fair value of these certain alternative investments. The ASU also requires disclosure by major category of investment about the attributes of the investments, such as the nature of any restrictions on the investor's ability to redeem its investments at the measurement date. The adoption of ASU 2009-12, did not have a material impact on PGE's consolidated financial position, consolidated results of operation, or consolidated cash flows.

New Accounting Pronouncement

On June 12, 2009, the FASB issued SFAS 167, *Amendments to FASB Interpretation No. 46(R)* (SFAS 167), a revision of FIN 46(R) that changes how a company determines when a variable interest entity (VIE) should be consolidated. The determination of whether a company is required to consolidate an entity is based on, among other things, an entity's purpose and design and a company's ability to direct the activities of the entity that most significantly impact the entity's economic performance. SFAS 167 requires a company to provide additional disclosures about its involvement with variable interest entities and what any significant change in risk exposure does to that involvement. A company will also be required to disclose how its involvement with a VIE affects the company's performance. SFAS 167 is effective for fiscal years beginning after November 15, 2009. Earlier application is prohibited. PGE is in the process of determining what impact, if any, that the adoption of SFAS 167, as codified within ASC 810, *Consolidation*, upon the adoption of SFAS 168, will have on its consolidated financial position, consolidated results of operation, or consolidated cash flows.

NOTE 3: BALANCE SHEET COMPONENTS

Accounts Receivable, Net

Accounts receivable is net of an allowance for uncollectible accounts of $5 million and $4 million as of December 31, 2009 and 2008, respectively. The following is the activity in the allowance for uncollectible accounts (in millions):

	Years Ended December 31,		
	2009	**2008**	**2007**
Balance as of beginning of year	$ 4	$ 5	$ 45
Increase (decrease) in provision	9	8	(34)
Amounts written off, less recoveries	(8)	(9)	(6)
Balance as of end of year	$ 5	$ 4	$ 5

Prior to January 1, 2006, PGE had established a reserve of $40 million related to pending legal matters between the Company and certain California parties related to wholesale energy transactions in the western markets from January 1, 2000 through June 20, 2001. In the first quarter of 2007, PGE reached a settlement that resolved these matters, resulting in the reversal of this reserve, which is reflected as a decrease in the provision for uncollectible accounts for the year ended December 31, 2007 in the table above.

Trust Accounts

PGE maintains two trust accounts: (1) the non-qualified benefit plan trust, which represents amounts set aside by the Company to fund its obligation under the non-qualified benefit plans, primarily the Supplemental Executive

Retirement Plan (SERP), management deferred compensation plans (MDCPs) and other non-qualified plans for certain current and former employees and directors, and (2) the nuclear decommissioning trust, which is restricted to reimbursing PGE for Trojan decommissioning expenditures and represents amounts collected from customers less qualified expenditures plus any realized and unrealized gains and losses on the investments held therein.

The trusts hold investments in cash, cash equivalents, marketable securities, and insurance contracts. The insurance contracts are recorded at cash surrender value, with any changes recorded in earnings. The trusts are comprised of the following investments as of December 31 (in millions):

	Nuclear Decommissioning Trust		Non-Qualified Benefit Plan Trust	
	2009	2008	2009	2008
Cash equivalents	$ 31	$ 27	$—	$—
Marketable securities, at fair value:				
Equity securities	—	—	21	23
Debt securities	19	19	4	3
Insurance contracts, at cash surrender value	—	—	22	20
Total	$ 50	$ 46	$ 47	$ 46

NOTE 4: FAIR VALUE OF FINANCIAL INSTRUMENTS

The fair value of financial instruments, both assets and liabilities recognized and not recognized in PGE's consolidated balance sheet, for which it is practicable to estimate fair value is as follows as of December 31, 2009 and 2008:

- The fair value of cash and cash equivalents and short-term debt approximate their carrying amounts due to the short-term nature of these balances.
- Derivative instruments are recorded at fair value and are based on published market indices as adjusted for other market factors such as location pricing differences or internally developed models;
- Certain trust assets, consisting of money market funds and fixed income securities included in the Nuclear decommissioning trust and marketable securities included in the Non-qualified benefit plan trust, are recorded at fair value and are based on quoted market prices; and
- The fair value of long-term debt is estimated based on the quoted market prices for the same or similar issues or on the current rates offered to PGE for debt of similar remaining maturities. As of December 31, 2009, the estimated aggregate fair value of PGE's long-term debt was $1,818 million, compared to its $1,744 million carrying amount. As of December 31, 2008, the estimated aggregate fair value of PGE's long-term debt was $1,286 million, compared to its $1,306 million carrying amount.

A fair value hierarchy is used to prioritize the inputs to the valuation techniques used to measure fair value. These three broad levels and application to the Company are discussed below.

Level 1—Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives, listed equities and U.S. government treasury securities.

Level 2—Pricing inputs are other than quoted market prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data, or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange-traded derivatives such as over-the-counter forwards and swaps.

Level 3—Pricing inputs include significant inputs that are generally less observable than objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. Level 3 instruments include those that may be more structured or otherwise tailored to customers' needs. At each balance sheet date, the Company performs an analysis of all instruments subject to fair value measurement and includes in Level 3 all of those whose fair value is based on significant unobservable inputs.

The Company's financial assets and liabilities whose fair values were recognized at fair value are as follows by level within the fair value hierarchy (in millions):

	Level 1	Level 2	Level 3	Total
As of December 31, 2009:				
Assets:				
Nuclear decommissioning trust (1):				
Cash	$ 31	$—	$—	$ 31
Debt securities:				
U.S. treasury securities	4	—	—	4
Corporate debt securities	—	8	—	8
Mortgage-backed securities	—	5	—	5
Municipal securities	—	2	—	2
Non-qualified benefit plan trust:				
Equity securities	21	—	—	21
Debt securities—mutual funds	4	—	—	4
Assets from price risk management activities (1)	—	13	—	13
	$ 60	$ 28	$—	$ 88
Liabilities—Liabilities from price risk management activities (1)	$—	$101	$154	$255
As of December 31, 2008:				
Assets:				
Nuclear decommissioning trust (1):				
Cash	$ 27	$—	$—	$ 27
Debt securities:				
Mortgage-backed securities	—	7	—	7
Corporate debt securities	—	4	—	4
Municipal securities	—	4	—	4
Other	—	4	—	4
Non-qualified benefit plan trust:				
Equity securities	23	—	—	23
Debt securities—mutual funds	3	—	—	3
Assets from price risk management activities (1)	—	33	6	39
	$ 53	$ 52	$ 6	$111
Liabilities—Liabilities from price risk management activities (1)	$—	$297	$129	$426

(1) Activities are subject to regulation, with certain gains and losses deferred pursuant to regulatory accounting and included in regulatory assets or regulatory liabilities as appropriate.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

Nuclear decommissioning trust assets reflect the assets held in trust to cover general decommissioning costs and operation of the Independent Spent Fuel Storage Installation (ISFSI) and consist of money market funds and fixed income securities. Non-qualified benefit plan trust reflects the assets held in trust to cover the obligations of PGE's non-qualified benefit plans and consist primarily of marketable securities. These assets also include investments recorded at cash surrender value, which are excluded from the table above.

Assets and liabilities from price risk management activities represent derivative transactions entered into by PGE to manage its exposure to commodity price risk and minimize net power costs for service to the Company's retail customers and may consist of forward, swap, and option contracts for electricity, natural gas, oil, and foreign currency, and futures contracts for natural gas and oil. PGE applies a market based approach to the fair value measurement of its derivative transactions. Inputs into the valuation of derivative activities include forward commodity and foreign exchange pricing, interest rates, volatility and correlation. PGE utilizes the Black-Scholes and Monte Carlo pricing models for commodity option contracts. Forward pricing, which employs the mid-point of the market's bid-ask spread, is derived using observed transactions in active markets, as well as historical experience as a participant in those markets, and is validated against nonbinding quotes from brokers with whom the Company transacts. Interest rates used to calculate the present value of derivative valuations incorporate PGE's borrowing ability. The Company also considered the liquidity of delivery points of executed transactions when determining where in the fair value hierarchy a transaction should be classified. PGE considers its creditworthiness and the creditworthiness of its counterparties when determining the appropriateness of a particular transaction's assigned Level in the fair value hierarchy.

Changes in the fair value of assets and liabilities from price risk management activities classified as Level 3 in the fair value hierarchy were as follows (in millions):

	Years Ended December 31,	
	2009	2008
Assets (liabilities) from price risk management activities, net as of beginning of year	$(123)	$ 1
Net realized and unrealized losses	(47)	(166)
Purchases, issuances, and settlements, net	—	(12)
Net transfers out of Level 3	16	54
Liabilities from price risk management activities, net as of end of year	$(154)	$(123)

Net realized and unrealized losses are recorded in Purchased power and fuel expense in the consolidated statements of income, and include $49 million in net losses in 2009 and $120 million in 2008, of Level 3 net realized and unrealized losses that have been fully offset by the effects of regulatory accounting.

NOTE 5: PRICE RISK MANAGEMENT

PGE participates in the wholesale marketplace in order to balance its supply of power, which consists of its own generating resources combined with wholesale market transactions, to meet the needs of its retail customers, manage risk, and administer its existing long-term wholesale contracts. Such activities include power purchases and sales resulting from economic dispatch decisions for its own generation. As a result of this ongoing business activity, PGE is exposed to commodity price risk and foreign currency exchange rate risk, where adverse changes in prices and/or rates may affect the Company's financial position, performance, or cash flow.

PGE utilizes derivative instruments, which may include forward, swap, and option contracts for electricity, natural gas, oil, and foreign currency, and futures contracts for natural gas and oil, in its retail electric utility activities to manage its exposure to commodity price risk and foreign exchange rate risk, mitigate the effects of market fluctuations, and minimize net power costs for service to its retail customers. These derivative instruments are recorded at fair value on the statement of financial position, with changes in fair value recorded in the statement of income. However, as a regulated entity, PGE recognizes a regulatory asset or liability in order to defer the gains and losses from derivative activity until realized, in accordance with ratemaking and cost recovery processes authorized by the OPUC. In effect, this accounting treatment defers the mark-to-market gains and losses on derivative activities until settlement, reducing volatility related to commodity price and foreign currency exchange rate risk. PGE may designate certain derivative instruments as cash flow hedges or may use derivative instruments as economic hedges. PGE does not engage in trading activities for non-retail purposes.

PGE has elected not to net on the balance sheet the positive and negative exposures resulting from derivative instruments entered into with counterparties where a master netting arrangement exists.

As of December 31, 2009, PGE's net volume related to its Price risk management assets and liabilities resulting from its derivative activities, which are expected to deliver or settle at various dates through 2014, was as follows (in millions):

Type	Volume
Commodity:	
Electricity	12 MWh
Natural gas	96 Decatherms
Foreign exchange	$ 5 Canadian

As of December 31, 2009, PGE's Assets and Liabilities from price risk management activities resulting from its derivative activities, offset by regulatory accounting, consist of the following (in millions):

	Asset Derivatives		Liability Derivatives	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
Derivatives not designated as hedging instruments:				
Commodity contracts:				
Electricity	Current assets	$ 6	Current liabilities	$ 57
Natural gas	Current assets	5	Current liabilities	71
Total current derivative activity		11 (1)		128
Commodity contracts:				
Electricity	Noncurrent assets	1	Noncurrent liabilities	24
Natural gas	Noncurrent assets	1	Noncurrent liabilities	103
Total long-term derivative activity		2 (2)		127
Total derivatives not designated as hedging instruments		$ 13		$255
Total derivatives		$ 13		$255

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

Net realized and unrealized losses on derivative transactions were recognized in the statement of income for the year ended December 31, 2009 as follows (in millions):

Derivatives not designated as hedging instruments	Location of net loss recognized in net income on derivative activities	Net loss recognized in net income on derivative activities *
Commodity contracts:		
Electricity	Purchased power and fuel expense	$ 79
Natural Gas	Purchased power and fuel expense	101

* Unrealized gains and losses and certain realized gains and losses are offset by regulatory accounting. Of the net loss recognized in net income for the year ended December 31, 2009, $98 million has been offset.

Assuming no changes in market prices and interest rates, the following table indicates the year in which the net unrealized loss recorded as of December 31, 2009 related to PGE's derivative activities would be realized as a result of the settlement of the underlying derivative instrument (in millions):

	2010	2011	2012	2013	Total
Commodity contracts:					
Electricity	$ 51	$17	$ 4	$ 1	$ 73
Natural gas	66	39	45	19	169
Net unrealized loss	$117	$56	$49	$20	$242

The Company's secured and unsecured debt is currently rated at investment grade by Moody's Investors Service (Moody's) and Standard and Poor's Ratings Services (S&P). Should Moody's and/or S&P reduce their rating on the Company's unsecured debt to below investment grade, PGE could be subject to requests by certain wholesale counterparties to post additional performance assurance collateral, in the form of cash or letters of credit, based on total portfolio positions with each of those counterparties and some other counterparties will have the right to terminate their agreements with the Company.

The aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a liability position as of December 31, 2009 was $216 million. As of December 31, 2009, the Company had $144 million in posted collateral associated with such liability positions, which consisted entirely of letters of credit. If the credit-risk-related contingent features underlying these agreements were triggered at December 31, 2009, the cash requirement would have been $207 million.

At December 31, 2009, contracts with four different counterparties represent approximately 70% and 46% of PGE's Price risk management assets and liabilities, respectively. Three counterparties represent 41%, 15%, and 14% of Price risk management assets. Three counterparties (two are also represented in the assets) represent 19%, 14%, and 13% of Price risk management liabilities. No other counterparty represents more than 10% of the Price risk management assets and liabilities.

See Note 4 for additional information concerning the determination of fair value for the Company's Price risk management assets and liabilities.

NOTE 6: REGULATORY ASSETS AND LIABILITIES

The majority of PGE's regulatory assets and liabilities are reflected in customer prices and are amortized over the period in which they are reflected in customer prices. Items not currently reflected in prices are pending before the regulatory body as discussed below.

Regulatory assets and liabilities consist of the following (in millions):

	Weighted Average Remaining Life	As of December 31, 2009		2008	
		Current	Noncurrent	Current	Noncurrent
Regulatory assets:					
Price risk management (1)	2 years	$118	$125	$194	$193
Pension and other postretirement plans (1)	(2)	—	196	—	232
Deferred income taxes (1)	(3)	—	91	—	88
Deferred broker settlements (1)	1 year	49	1	—	19
Boardman power cost deferral	(4)	17	—	—	34
Debt reacquisition costs (1)	24 years	—	26	—	28
Utility rate treatment of income taxes	1 year	7	—	—	17
Other	Various	6	26	—	20
Total regulatory assets		$197	$465	$194	$631
Regulatory liabilities:					
Asset retirement removal costs (5)	(3)	$—	$541	$—	$494
Utility rate treatment of income taxes	2 years	9	24	24	19
Asset retirement obligations (5)	(3)	—	30	—	26
Trojan ISFSI pollution control tax credits	(6)	—	17	—	17
Power Cost Adjustment Mechanism	1 year	1	—	19	—
Trojan refund liability	—	—	—	—	34
Other	Various	17	42	—	50
Total regulatory liabilities		$ 27	$654	$ 43	$640

(1) Does not include a return on investment.
(2) Recovery expected over the average service life of employees. For additional information see Note 2.
(3) Recovery expected over the estimated lives of the assets.
(4) Recovery will occur in the first quarter of 2010.
(5) Included in rate base for ratemaking purposes.
(6) Timing of refund not yet determined.

As of December 31, 2009, PGE had regulatory assets of $56 million earning a return on investment at the following rates: (1) $34 million at PGE's authorized cost of capital, currently 8.284%; (2) $13 million at the approved rate for deferred accounts under amortization, ranging from 2.05% to 4.27%, depending on the year of approval; and (3) $9 million earning a return by inclusion in rate base.

Price risk management represents the difference between the recognition of unrealized gains and losses on derivative instruments related to price risk management activities and their realization and subsequent recovery in rates. See Note 5.

Pension and other postretirement plans represents unrecognized components of the benefit plans' funded status, which are recoverable in rates when recognized in net periodic benefit cost. See Note 10.

Deferred income taxes represents income tax benefits resulting from property-related timing differences that previously flowed to customers and will be included in rates when the temporary differences reverse. See Note 11.

Deferred broker settlements consist of transactions that have been financially settled by clearing brokers prior to the contract delivery date. These gains and losses are deferred for future rate recovery in the corresponding contract settlement month.

Boardman power cost deferral represents that portion of excess replacement power costs, plus accrued interest, associated with the forced outage of Boardman from November 18, 2005 through February 5, 2006, which was deferred for later ratemaking treatment. In the fourth quarter of 2009, the deferred amount was reduced by $18 million pursuant to a February 12, 2010 OPUC order on the amount to be recovered from customers; such reduction was charged to Purchased power and fuel expense. Pursuant to the order, collection of the remaining deferred balance will be offset in early 2010 with certain credits currently owed to customers related to accrued savings on decommissioning activities at PGE's closed Trojan Nuclear Plant; such amount is included in Other regulatory liabilities.

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

Utility rate treatment of income taxes regulatory asset or regulatory liability is established pursuant to Oregon Senate Bill 408 (SB 408), which was enacted in 2005. SB 408 requires regulated investor-owned utilities that provide electric or natural gas service to more closely match income tax amounts forecasted to be collected in revenues with the amount of income taxes paid to governmental entities by the investor-owned utilities or their consolidated group. The law requires a report to be filed annually with the OPUC regarding the amount of taxes paid by the utility and the amount of taxes authorized to be collected in rates. If the difference between these two amounts is greater than $100,000, the utility is required to adjust rates prospectively. In any given reporting year, a regulatory liability is established for future refunds to customers while a regulatory asset is established for future collections from customers, with interest accrued thereon as approved by the OPUC.

Trojan refund liability was established as a result of the OPUC order issued on September 30, 2008 requiring a $33.1 million refund to customers for the settlement of certain Trojan-related matters. By December 31, 2009, PGE had substantially completed the refund to customers, including interest at 9.6% from September 30, 2008 through the date the funds were distributed.

NOTE 7: ASSET RETIREMENT OBLIGATIONS

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

	As of December 31,	
	2009	2008
Trojan decommissioning activities	$39	$37
Utility plant	14	11
Non-utility property	10	10
Asset retirement obligations	$63	$58

Trojan decommissioning activities represents the present value of future decommissioning expenditures for the plant which ceased operation in 1993. The remaining decommissioning activities consist of the long-term operation and decommissioning of the ISFSI, an NRC-licensed interim dry storage facility that houses the spent nuclear fuel at the plant site until permanent off-site storage is available. Decommissioning of the ISFSI and final site restoration activities will begin once the spent fuel is shipped to a U.S. Department of Energy (USDOE) facility, which is not expected prior to 2033.

Utility plant represents AROs which have been recognized for the Company's thermal and wind generation sites, distribution and transmission assets where disposal is governed by environmental regulation, as well as the Bull Run hydro project. Decommissioning work has been substantially completed at Bull Run as of December 31, 2009, with the possible demolition of the powerhouse planned for summer 2010 if an alternative use for the facility is not chosen. Environmental monitoring is scheduled to continue through 2012.

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

	Years Ended December 31,		
	2009	2008	2007
Balance as of beginning of year	$ 58	$ 91	$134
Liabilities incurred	—	—	7
Liabilities settled	(4)	(13)	(9)
Accretion expense	4	2	7
Revisions in estimated cash flows	5	(22)	(48)
Balance as of end of year	$ 63	$ 58	$ 91

Pursuant to regulation, utility plant AROs are included in depreciation expense and in prices charged to customers. Any differences in the timing of recognition of costs for financial reporting and ratemaking purposes are deferred as a regulatory asset or regulatory liability. Recovery of Trojan decommissioning costs is included in PGE's retail prices, currently at $5 million annually, with an equal amount recorded in Depreciation and amortization expense.

PGE maintains a separate trust account, Nuclear decommissioning trust in the consolidated balance sheet, for funds collected from customers through rates to cover the cost of Trojan decommissioning activities. See "Trust Accounts" in Note 3 for additional information on the nuclear decommissioning trust account.

The Oak Grove hydro project and transmission and distribution plant located on public right-of-ways and on certain easements meet the requirements of a legal obligation and will require removal when the plant is no longer in service. An ARO liability is not currently measurable however as management believes that these assets will be used in utility operations for the foreseeable future. Ongoing removable activity as equipment is replaced is charged to accumulated asset retirement removal costs, included in Regulatory liabilities.

NOTE 8: REVOLVING CREDIT FACILITIES

PGE has the following unsecured revolving credit facilities:

- A $370 million unsecured revolving credit facility with a group of banks, of which $10 million is scheduled to terminate in July 2012 and $360 million in July 2013;
- A $200 million credit facility with a group of banks, which is scheduled to terminate in December 2012; and
- A $30 million credit facility with a bank, which is scheduled to terminate in June 2012.

Pursuant to the individual terms of the agreements, all credit facilities may be used for general corporate purposes and as backup for commercial paper borrowings. The $370 million and $30 million credit facilities also permit the issuance of standby letters of credit. PGE may borrow for one, two, three, or six months at a fixed interest rate established at the time of the borrowing, or at a variable interest rate for any period up to the then remaining term of the applicable credit facility. All credit facilities require annual fees based on PGE's unsecured credit ratings, and contain customary covenants and default provisions, including a requirement that limits consolidated indebtedness, as defined in the agreement, to 65% of total capitalization. As of December 31, 2009, PGE was in compliance with this covenant with a 53.1% debt ratio.

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

Pursuant to an order issued by the FERC, the Company is authorized to issue short-term debt up to $750 million through February 6, 2012. The authorization provides that if utility assets financed by unsecured debt are divested, then a proportionate share of the unsecured debt must also be divested.

As of December 31, 2009, PGE had no borrowings or commercial paper outstanding under the credit facilities and had $163 million in letters of credit outstanding. As of December 31, 2009, the aggregate unused available credit under the credit facilities is $437 million.

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

	Years Ended December 31,		
	2009	2008	2007
Average daily amount of short-term debt outstanding	$ 28	$ 33	$ 22
Weighted daily average interest rate [(1)]	1.3%	3.8%	5.6%
Maximum amount outstanding during the year	$205	$199	$ 93

(1) Excludes the effect of commitment fees, facility fees and other financing fees.

NOTE 9: LONG-TERM DEBT

Long-term debt consists of the following (in millions):

	As of December 31, 2009	As of December 31, 2008
First Mortgage Bonds, rates range from 4.45% to 9.31%, with a weighted average rate of 6.0% in 2009 and 2008, due at various dates through 2040	$1,550	$ 970
Pollution Control Revenue Bonds:		
Port of Morrow, Oregon, 5.2% rate to 2009 and variable thereafter, due 2033	23	23
City of Forsyth, Montana, 5.2% to 5.45% rate to 2009 and variable thereafter, due 2033	119	119
Port of St. Helens, Oregon, 4.8% to 5.25% rate, due 2010 to 2014	47	47
Total Pollution Control Revenue Bonds	189	189
7.875% unsecured notes, due March 10, 2010	149	149
Purchase of pollution control revenue bonds	(142)	—
Unamortized debt discount	(2)	(2)
Total long-term debt	1,744	1,306
Less: current portion of long-term debt	(186)	(142)
Long-term debt, net of current portion	$1,558	$1,164

First Mortgage Bonds—The Indenture securing PGE's First Mortgage Bonds constitutes a direct first mortgage lien on substantially all utility property, other than expressly excepted property. During 2009, PGE issued a total of $580 million of first mortgage bonds as follows:

- On January 15th, $67 million of 6.8% Series due January 15, 2016, with interest payable semi-annually on January 15th and July 15th;
- On January 15th, $63 million of 6.5% Series due January 15, 2014, with interest payable semi-annually on January 15th and July 15th;
- On April 16th, $300 million of 6.1% Series due April 15, 2019, with interest payable semi-annually on April 15th and October 15th; and
- On November 30th, $150 million of 5.43% Series due May 3, 2040, with interest payable semi-annually on May 15th and November 15th.

On January 15, 2010, PGE issued $70 million of 3.46% Series First Mortgage Bonds that mature January 15, 2015, with interest payable semi-annually on January 15th and July 15th.

Pollution Control Revenue Bonds—On May 1, 2009, PGE repurchased $142 million of Pollution Control Revenue Bonds (Bonds), consisting of $23 million issued through the Port of Morrow, Oregon, and $119 million issued through the City of Forsyth, Montana. PGE has the option to remarket the Bonds and can choose a new interest rate period that would be daily, weekly, or a fixed term. The new interest rate would be based on market conditions at the time of remarketing and could be backed by first mortgage bonds or a bank letter of credit depending on market conditions.

As of December 31, 2009, the future minimum principal payments on long-term debt are as follows (in millions):

Years ending December 31:	
2010	$ 186
2011	—
2012	100
2013	100
2014	73
Thereafter	1,285
	$1,744

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

NOTE 10: EMPLOYEE BENEFITS

Pension and Other Postretirement Plans

Defined Benefit Pension Plan—PGE sponsors a non-contributory defined benefit pension plan, of which substantially all participants are current or former PGE employees. The assets of the pension plan are held in a trust and are comprised in investment vehicles such as: common stocks, mutual funds, private equity funds, fixed income securities, common and collective trust funds, partnerships/joint ventures, corporate debt securities, and other investments; all of which are recorded at fair value. Pension plan calculations include several assumptions which are reviewed annually and are updated as appropriate. The measurement date for the pension plan is December 31.

PGE made no contributions to the pension plan in 2009, 2008, and 2007, and does not expect to make any contribution in 2010. As a result of the underfunded status of the pension plan as of January 1, 2010, the Company is expected to make an estimated contribution of $19 million in 2011.

Effective January 31, 2009, the pension plan was closed to new non-bargaining employees, with no changes in benefits to current participants of the pension plan. For non-bargaining employees hired on or after February 1, 2009, the pension plan has been replaced with a new contribution to the defined contribution plan. For additional information, see description of the Company's 401(k) plan included in this Note. Effective January 1, 1999, the pension plan was closed to new bargaining employees.

Other Postretirement Benefits—PGE has non-contributory postretirement health and life insurance plans (collectively "Other Postretirement Benefits" in the following tables). Employees are covered under a Defined Dollar Medical Benefit Plan which limits PGE's obligation by establishing a maximum benefit per employee with employees paying the additional cost. Contributions made to a voluntary employees' beneficiary association trust are used to fund these plans. The assets of other postretirement plans are comprised of investments in: money market funds, common stocks, common and collective trust funds, partnerships/joint ventures, and registered investment companies, all of which are recorded at fair value. Costs of these plans, based upon an actuarial study, are included in rates charged to customers. Postretirement benefit plan calculations include several assumptions which are reviewed annually with PGE's consulting actuaries and trust investment consultants and updated as appropriate.

PGE has Health Reimbursement Accounts (HRAs) for its employees. Contributions are made to trust accounts to provide for claims by retirees for qualified medical costs. For active bargaining employees, the participants' accounts are credited with 58% of the value of the employee's accumulated sick time as of April 30, 2004, plus

100% of their earned time off accumulated at the time of retirement. Between July 1, 2007 and June 30, 2008, the Company made additional contributions to the trust of $0.25 per compensable hour for each bargaining unit participant, increasing to $0.50 per compensable hour from July 1, 2008 through March 3, 2009. The compensable hour contribution as of March 4, 2009 has been redirected to the participants' 401(k) plan. For active non-bargaining employees, the Company grants a fixed dollar amount that will become available for qualified medical expenses upon their retirement.

Minimal contributions were made to the postretirement and non-bargaining HRA plans in 2009, 2008 and 2007. Contributions totaling $1 million were made to the bargaining unit HRA in 2009, 2008 and 2007. No contributions are currently expected to be made to the other postretirement plans in 2010. The measurement date for the postretirement plans is December 31.

Non-Qualified Benefit Plans—The Non-Qualified Benefit Plans (NQBP) in the following tables consist primarily of obligations for a SERP, which was closed to new participants in 1997. Investments in a non-qualified benefit plan trust, consisting of trust-owned life insurance policies and marketable securities, provide funding for the future requirements of these plans. These trust assets are included in the accompanying tables for informational purposes only and are not considered segregated and restricted under current accounting standards. The investments in marketable securities, consisting of money market, bond, and equity mutual funds, are classified as trading and recorded at fair value. The measurement date for the non-qualified benefit plans is December 31.

Other Compensation Plans—In addition to the non-qualified benefit plans discussed above, PGE provides certain employees with benefits under unfunded MDCPs, whereby participants may defer a portion of their compensation, as well as other non-qualified plans for certain employees and directors. PGE holds investments in a non-qualified benefit plan trust which are intended to be the primary source for funding these plans.

The following table provides information on the trust assets and plan liabilities included in PGE's consolidated balance sheets as of December 31, 2009 and 2008 (in millions):

	2009			2008		
	NQBP	**MDCP**	**Total**	**NQBP**	**MDCP**	**Total**
Non-qualified benefit plan trust	$20	$27	$47	$18	$28	$46
Non-qualified benefit plan liabilities [(1)]	25	71	96	23	68	91

(1) For the NQBP, excludes the current portion of $2 million in 2009 and 2008, which is classified in Other current liabilities in the consolidated balance sheets.

Investment Policy and Asset Allocation—The Board of Directors of PGE appoints an Investment Committee, which is comprised of officers of the Company. In addition, the Board also establishes the Company's asset allocation of risk. The Investment Committee is then responsible for implementation and oversight of the asset allocation. The Company's investment policy for its pension and other postretirement plans is to balance risk and return through a diversified portfolio of equity securities, fixed income securities and other alternative investments. The commitments to each class are controlled by an asset deployment and cash management strategy that takes profits from asset classes whose allocations have shifted above their target ranges to fund benefit payments and investments in asset classes whose allocations have shifted below their target ranges.

The asset allocations for the plans, and the target allocation, are as follows:

	December 31, 2009	December 31, 2008	Target
Defined Benefit Pension Plan:			
Equity securities	67%	68%	67%
Debt securities	33	32	33
	100%	100%	100%
Other Postretirement Benefit Plans:			
Equity securities	50%	60%	60%
Debt securities	50	40	40
	100%	100%	100%
Non-Qualified Benefits Plans:			
Debt securities	8%	7%	16%
Equity securities	46	51	38
Insurance contracts	46	42	46
	100%	100%	100%

The Company's overall investment strategy is to meet the goals and objectives of the individual plans through a wide diversification of asset types, fund strategies, and fund managers. Equity securities primarily include investments across the capitalization ranges and style biases, both domestically and internationally. Fixed income securities include, but are not limited to, corporate bonds of companies from diversified industries, mortgage-backed securities, and U.S. Treasuries. Other types of investments include investments in hedge funds and private equity funds that follow several different strategies.

The fair values of the Company's pension plan assets and other postretirement benefit plan assets as of December 31, 2009 by asset category are as follows (in millions):

	Level 1	Level 2	Level 3	Total
Defined Benefit Pension Plan assets:				
Equity securities:				
U.S. small cap core	$ 11	$—	$—	$ 11
U.S. small cap value	12	—	—	12
U.S. micro cap	12	—	—	12
U.S. large cap growth	—	24	—	24
U.S. large cap value	—	23	—	23
Large cap long/short	—	47	—	47
International large cap growth	—	46	—	46
Fixed income securities:				
U.S. core plus	—	34	—	34
U.S. long government/credit	—	32	—	32
Short duration	—	2	—	2
Mutual funds (1)	123	—	—	123
Private equity funds (2)	—	—	17	17
U.S. large cap futures and U.S. hedge funds (3)	—	—	23	23
	$158	$208	$ 40	$406
Other Postretirement Benefit Plans assets:				
Equity securities:				
U.S. small cap core	$ 1	$—	$—	$ 1
U.S. large cap growth	—	2	—	2
U.S. large cap value	—	1	—	1
International large cap growth	—	1	—	1
Fixed income securities:				
Short term investment fund	—	7	—	7
Mutual funds	7	—	—	7
	$ 8	$ 11	$—	$ 19

(1) Mutual funds: a combination of small capitalization growth equity and medium and long duration fixed income funds which can invest across all of the major fixed income sectors. These mutual funds are actively managed.
(2) Private equity: a combination of primary and secondary fund-of-funds which hold ownership positions in privately held companies across the major domestic and international private equity sectors, including but not limited to, venture capital, buyout and special situations.
(3) Portable alpha: an investment mandate comprised of long position in S&P 500 futures contracts and a hedge fund-of-funds comprised of diversified group, by sector and market capitalization of long only, short only and/or both long/short equity hedge funds.

Changes in the fair value of assets held by the pension plan classified as Level 3 in the fair value hierarchy presented in the table above were as follows for the year ended December 31, 2009 (in millions):

	Private equity	U.S. large cap and U.S. hedge funds	Total Level 3
Balance as of December 31, 2008	$ 16	$18	$34
Purchases and sales	1	1	2
Unrealized gain on assets	—	4	4
Balance as of December 31, 2009	$ 17	$23	$40

Trust assets and obligations related to the other compensation plans are not included in the following tables.

The following tables provide certain information with respect to the Company's defined benefit pension plan, other postretirement benefits, and non-qualified benefit plans as of and for the years ended December 31, 2009 and 2008 (dollars in millions):

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2009	2008	2009	2008	2009	2008
Benefit obligation:						
As of January 1	$467	$ 475	$ 73	$ 68	$ 25	$ 24
Service cost	11	12	2	2	—	—
Interest cost	31	30	4	4	2	2
Plan amendments	1	—	—	—	—	—
Participants' contributions	—	—	2	1	—	—
Actuarial (gain) loss	5	(24)	2	3	2	1
Benefit payments	(24)	(26)	(6)	(5)	(2)	(2)
As of December 31	$491	$ 467	$ 77	$ 73	$ 27	$ 25
Fair value of plan assets:						
As of January 1	$347	$ 518	$ 19	$ 27	$ 18	$ 25
Actual return on plan assets	83	(145)	3	(6)	4	(5)
Company contributions	—	—	1	2	—	—
Participants' contributions	—	—	2	1	—	—
Benefit payments	(24)	(26)	(6)	(5)	(2)	(2)
As of December 31	$406	$ 347	$ 19	$ 19	$ 20	$ 18
Unfunded position as of December 31	$ (85)	$(120)	$ (58)	$ (54)	$ (7)	$ (7)

	Defined Benefit Pension Plan		Other Postretirement Benefits		Non-Qualified Benefit Plans	
	2009	2008	2009	2008	2009	2008
Accumulated benefit plan obligation as of December 31	$ 446	$ 420	N/A	N/A	$ 26	$ 25
Classification in consolidated balance sheet:						
Noncurrent asset	$ —	$ —	$ —	$ —	$ 20	$ 18
Current liability	—	—	—	—	(2)	(2)
Noncurrent liability	(85)	(120)	(58)	(54)	(25)	(23)
Net liability	$ (85)	$(120)	$ (58)	$ (54)	$ (7)	$ (7)
Amounts included in comprehensive income:						
Net actuarial (gain) loss	$ (35)	$ 166	$ —	$ 12	$ 2	$ 1
Prior service cost	1	—	—	—	—	—
Amortization of net actuarial gain (loss)	—	—	(1)	—	—	1
Amortization of prior service cost	(1)	(1)	(1)	(1)	—	—
Amortization of transition obligation	—	—	—	(1)	—	—
	$ (35)	$ 165	$ (2)	$ 10	$ 2	$ 2
Amounts included in AOCL (1):						
Net actuarial loss	$ 167	$ 202	$ 20	$ 21	$ 9	$ 8
Prior service cost	3	2	6	7	—	—
	$ 170	$ 204	$ 26	$ 28	$ 9	$ 8
Assumptions used:						
Average discount rate used to calculate benefit obligation	5.90%	6.90%	4.66% - 5.92%	5.77% - 6.09%	5.90%	6.90%
Weighted average rate of increase in future compensation levels	3.79%	4.42%	5.07%	5.07%	N/A	N/A
Long-term rate of return on plan assets	8.50%	9.00%	6.88%	7.67%	N/A	N/A

(1) Amounts included in AOCL related to the Company's defined benefit pension plan and other postretirement benefits are transferred to Regulatory assets due to the future recoverability from retail customers. Accordingly, as of the balance sheet date, such amounts are included in Regulatory assets.

Net periodic benefit cost consists of the following for the years ended December 31 (in millions):

	Defined Benefit Pension Plan			Other Postretirement Benefits			Non-Qualified Benefit Plans		
	2009	2008	2007	2009	2008	2007	2009	2008	2007
Service cost	$ 11	$ 12	$ 13	$ 2	$ 2	$ 2	$—	$—	$—
Interest cost on benefit obligation	31	30	27	4	4	4	2	2	1
Expected return on plan assets	(43)	(45)	(42)	(1)	(2)	(2)	—	—	—
Amortization of transition obligation	—	—	—	—	1	1	—	—	—
Amortization of prior service cost	1	1	1	1	1	3	—	—	—
Amortization of net actuarial loss	—	—	3	1	—	—	—	—	1
Net periodic benefit cost	$—	$ (2)	$ 2	$ 7	$ 6	$ 8	$ 2	$ 2	$ 2

PGE estimates that $7 million will be amortized from AOCL into net periodic benefit cost in 2010, consisting of a net actuarial loss of $3 million for pension benefits, $1 million for non-qualified benefits and $1 million for other postretirement benefits, and prior service cost of $1 million for pension benefits and $1 million for other postretirement benefits.

The following table summarizes the benefits expected to be paid to participants in each of the next five years and in the aggregate for the five years thereafter (in millions):

	Payments Due					
	2010	2011	2012	2013	2014	2015 - 2019
Defined benefit pension plan	$27	$29	$31	$33	$34	$187
Other postretirement benefits	6	6	6	6	6	28
Non-qualified benefit plans	2	2	3	2	3	12
Total	$35	$37	$40	$41	$43	$227

All of the plans develop expected long-term rates of return for the major asset classes using long-term historical returns, with adjustments based on current levels and forecasts of inflation, interest rates, and economic growth. Also included are incremental rates of return provided by investment managers whose returns are expected to be greater than the markets in which they invest.

For measurement purposes, a 7.5% annual rate of increase in the per capita cost of covered health care benefits is assumed for 2010. The rate is assumed to decrease to 5% by 2015 and remain at that level thereafter. Assumed health care cost trend rates can affect amounts reported for the health care plans. A one-percentage point increase or decrease in assumed health care cost trend rates would not have a material impact on total service or interest cost, but would increase the postretirement benefit obligation by $1 million and decrease it by $1 million, respectively.

401(k) Retirement Savings Plan

PGE sponsors a 401(k) Plan, which covers substantially all employees. For eligible employees hired prior to February 1, 2009, employee contributions to the 401(k) Plan, made on a "pre-tax" basis, are matched by the Company up to 6% of base pay. For contributions made by eligible employees hired after January 31, 2009, and/or who are not covered by a defined benefit pension plan, the Company will match up to 5% of the participating employee's base salary. In addition, PGE makes an additional 5% contribution for these employees regardless of whether or not the employees make a contribution.

For bargaining employees, contributions are based upon provisions of the International Brotherhood of Electrical Workers Local 125 agreement that became effective on March 1, 2009. The following additions were made to the 401(k) plan for active bargaining employees:

- Effective March 4, 2009, the $0.50 per compensable hour contribution, previously deposited into the employee's HRA, is re-directed to the participants' 401(k) plan. This contribution to the participants' 401(k) plan will increase to $1.00 per compensable hour effective November 1, 2011.
- Effective March 3, 2010, employees will receive an additional 1% Company contribution based on the employee's base salary. This is a Company contribution regardless of whether or not the employee makes a contribution.

All contributions are invested in accordance with employees' elections, limited to investment options available under the 401(k) Plan. During each of the years ended December 31, 2009, 2008, and 2007, PGE made contributions of approximately $14 million.

NOTE 11: INCOME TAXES

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

	Years Ended December 31,		
	2009	2008	2007
Current:			
Federal	$ (46)	$12	$50
State and local	—	1	3
	(46)	13	53
Deferred:			
Federal	78	20	20
State and local	6	4	4
	84	24	24
Investment tax credit adjustments	(2)	(2)	(3)
Income tax expense	$ 36	$35	$74

The significant differences between the U.S. federal statutory rate and PGE's effective tax rate for financial reporting purposes are as follows:

	Years Ended December 31,		
	2009	2008	2007
Federal statutory tax rate	35.0%	35.0%	35.0%
Federal tax credits	(8.3)	(6.6)	—
State and local taxes, net of federal tax benefit	3.4	1.4	2.3
Flow through depreciation and cost basis differences	(1.6)	(0.8)	(1.5)
Investment tax credit amortization	(1.5)	(1.6)	(1.5)
Other	1.8	1.0	(0.5)
Effective tax rate	28.8%	28.4%	33.8%

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

	As of December 31, 2009	As of December 31, 2008
Deferred income tax assets:		
Regulatory liabilities	$ 278	$ 288
Price risk management	98	164
Employee benefits	87	97
Depreciation and amortization	26	20
Other	18	13
Valuation allowance	(3)	—
Total deferred income tax assets	504	582
Deferred income tax liabilities:		
Depreciation and amortization	646	559
Price risk management	117	172
Employee benefits	48	62
Regulatory assets	37	48
Other	31	28
Total deferred income tax liabilities	879	869
Deferred income tax liability, net	$(375)	$(287)
Classification of net deferred income taxes:		
Current deferred income tax asset (1)	$ —	$ 17
Current deferred income tax liability (2)	(19)	—
Noncurrent deferred income tax liability	(356)	(304)
	$(375)	$(287)

(1) Included in Other current assets in the consolidated balance sheet as of December 31, 2008.
(2) Included in Other current liabilities in the consolidated balance sheet as of December 31, 2009.

The valuation allowance for deferred tax assets as of December 31, 2009 was $3 million. The net change in the total valuation allowance for the year ended December 31, 2009 was an increase of $3 million. The valuation allowance as of December 31, 2009 relates to state tax credit carryforwards that, in the judgment of management, are not more likely than not to be realized.

As of December 31, 2009, PGE had net operating loss carryforwards for state income tax purposes of $0.4 million, which are available to reduce future state taxable income through 2024. In addition, PGE has Oregon tax credit carryforwards of approximately $12 million, which are available to reduce future state income taxes between 2010 and 2017.

PGE generated approximately $13 million of Oregon tax credits that, due to taxable income limitations, were not utilized by Enron (former parent company of PGE) prior to the separation of the two companies on April 3, 2006. Prior to 2006, pursuant to a tax sharing agreement, PGE utilized these tax credits to reduce its tax payment obligations to Enron. In 2008, PGE made an assessment that it is remote that Enron will be able to utilize these tax credits. Therefore, the realization of such tax credits by PGE was reflected as an adjustment to equity, net of the related federal tax effect, during the year ended December 31, 2008.

PGE files income tax returns in the U.S. federal jurisdiction, the states of Oregon and Montana, and certain local jurisdictions. Open tax years are 2006 and subsequent years for federal, state, and local tax purposes. The Internal Revenue Service informed PGE that examination of PGE's income tax returns for 2007 and 2008 will commence in the first quarter of 2010. The Company is not currently under examination by state or local tax authorities.

NOTE 12: EMPLOYEE STOCK PURCHASE PLAN

In May 2007, PGE shareholders approved the Portland General Electric Company 2007 Employee Stock Purchase Plan (ESPP), under which a total of 625,000 shares may be issued. The ESPP permits all eligible Company employees to purchase shares of PGE common stock through regular payroll deductions, which are limited to 10% of base pay. Each year, employees may purchase up to a maximum of $25,000 worth of stock (based on fair market value on the purchase date) or 1,500 shares, whichever is less. There are two six-month offering periods each year, January 1 - June 30 and July 1 - December 31, during which eligible employees may purchase shares of PGE common stock at a price equal to 95% of the fair market value of the stock on the purchase date, the last day of the offering period. During the years ended December 31, 2009, 2008, and 2007, the Company issued 29,648 shares, 25,586 shares, and 8,179 shares, respectively, under the ESPP, with proceeds totaling approximately $0.6 million, $0.5 million, and $0.2 million, respectively.

NOTE 13: STOCK-BASED COMPENSATION EXPENSE

Pursuant to the Portland General Electric Company 2006 Stock Incentive Plan (the Plan), the Company may grant a variety of equity-based awards, including restricted stock units with time-based vesting conditions (Restricted Stock Units) and performance-based vesting conditions (Performance Stock Units) to non-employee directors, officers and certain key employees. Service requirements generally must be met for stock units to vest. For each grant, the number of Stock Units is determined by dividing the specified award amount for each grantee by the closing stock price on the date of grant. A total of 4,687,500 shares of common stock were registered for future issuance under the Plan, of which 4,095,570 shares remain available for future issuance as of December 31, 2009.

Restricted Stock Units vest in either equal installments over a one-year period on the last day of each calendar quarter, over a three-year period on each anniversary of the grant date, or at the end of a three-year period following the grant date.

Performance Stock Units vest if performance goals are met at the end of a three-year performance period. Vesting of Performance Stock Units will be calculated by multiplying the number of units granted by a performance percentage determined by the Compensation and Human Resources Committee of PGE's Board of Directors. The performance percentage will be calculated based on the extent to which the performance goals are met. In accordance with the Plan, however, in determining results relative to these goals, the committee may disregard or offset the effect of extraordinary, unusual or non-recurring items. Based on the attainment of the performance goals, the awards can range from zero to 150% of the grant.

Outstanding Restricted and Performance Stock Units provide for the payment of one Dividend Equivalent Right (DER) for each stock unit, which is an amount equal to dividends paid to shareholders on a share of PGE's common stock. The DERs vest on the same schedule as the stock units and are settled in cash (for grants to non-employee directors) or shares of PGE common stock valued either at the closing stock price on the vesting date (for Performance Stock Unit grants) or dividend payment date (for all other grants). The cash from the settlement of the DERs for non-employee directors may be deferred under the terms of the Portland General Electric Company 2006 Outside Directors' Deferred Compensation Plan.

Restricted and Performance Stock Unit activity is summarized in the following table:

	Units	Weighted Average Grant Date Fair Value
Outstanding as of December 31, 2006	180,180	$24.97
Granted	100,425	28.44
Forfeited	(7,194)	25.14
Vested	(20,160)	25.76
Outstanding as of December 31, 2007	253,251	26.28
Granted	133,199	22.66
Forfeited	(3,392)	25.02
Vested	(22,676)	24.87
Outstanding as of December 31, 2008	360,382	25.04
Granted	243,574	14.95
Forfeited	(4,847)	24.85
Vested	(176,846)	23.60
Outstanding as of December 31, 2009	422,263	19.82

The vesting of Restricted and Performance Stock Units presented in the table above differ from the number of shares issued for the vesting of restricted stock units on the consolidated statements of shareholders' equity because of the payment of income taxes on behalf of the employees, in the form of shares, and the vesting of DERs, which totaled 48,671 shares in 2009, 2,792 shares in 2008, and 3,319 shares in 2007.

The weighted average fair value is measured based on the closing price of PGE common stock on the date of grant. For the years ended December 31, 2009, 2008 and 2007, PGE recorded $1.4 million, $4 million and $2.8 million, respectively, of stock-based compensation expense, which is included in Administrative and other expense in the consolidated statements of income. The recorded $1.4 million expense for 2009 is different than the amount reported in the consolidated statement of shareholders' equity for Stock-based compensation due primarily to the impact from the income tax payments made on behalf of employees. The net impact to equity from the income tax payments, partially offset by the issuance of DERs, resulted in a $1.0 million charge to equity not reported in Administrative and other expenses in the consolidated statement of income.

As of December 31, 2009, unrecognized stock-based compensation expense was $1.9 million, of which $1.0 million and $0.9 million is expected to be expensed in 2010 and 2011, respectively. Stock-based compensation expense was calculated assuming the attainment of performance goals that would allow the vesting of 82.3%, 0%, and 120.6% of awarded Performance Stock Units for 2009, 2008, and 2007, respectively, with an estimated 5% forfeiture rate. No stock-based compensation costs have been capitalized and the plan had no material impact on cash flow for the years ended December 31, 2009, 2008, or 2007.

NOTE 14: EARNINGS PER SHARE

Basic earnings per share is computed based on the weighted average number of common shares outstanding during the year. Diluted earnings per share is computed using the weighted average number of common shares outstanding and the effect of dilutive potential common shares outstanding during the year using the treasury stock method. Dilutive potential common shares consist of Restricted Stock Units. Unvested Performance Stock Units and related DERs are not included in the computation of dilutive securities because vesting of these instruments is dependent upon three-year performance periods.

Components of basic and diluted earnings per share are as follows:

	Years Ended December 31,		
	2009	2008	2007
Numerator (in millions):			
Net income attributable to Portland General Electric Company common shareholders	$ 95	$ 87	$ 145
Denominator (in thousands):			
Weighted average common shares outstanding—basic	72,790	62,544	62,512
Dilutive effect of unvested restricted stock units and employee stock purchase plan shares	62	37	22
Weighted average common shares outstanding—diluted	72,852	62,581	62,534
Earnings per share basic and diluted	$ 1.31	$ 1.39	$ 2.33

Basic and diluted earnings per share amounts are calculated based on actual amounts rather than the rounded amounts presented in the table above and on the consolidated statements of income. Accordingly, calculations using the rounded amounts presented for net income and weighted average shares outstanding may yield results that vary slightly from the earnings per share amounts presented in the table above.

NOTE 15: COMMITMENTS AND GUARANTEES

Commitments

As of December 31, 2009, PGE's future minimum payments pursuant to purchase obligations for the following five years and thereafter are as follows (in millions):

	Payments Due						
	2010	2011	2012	2013	2014	There-after	Total
Capital and other purchase commitments	$315	$ 36	$ 7	$ 8	$ 1	$ 18	$ 385
Purchased power and fuel:							
Electricity purchases	324	89	65	66	63	521	1,128
Capacity contracts	22	21	20	20	20	38	141
Public Utility Districts	7	7	5	5	5	34	63
Natural gas	97	36	17	16	13	29	208
Coal and transportation	20	17	3	3	—	—	43
Operating leases	8	9	9	10	10	234	280
Total	$793	$215	$126	$128	$112	$874	$2,248

Capital and other purchase commitments—Certain commitments have been made for capital and other purchases for 2010 and beyond. Such commitments include those related to hydro license agreements, Biglow Canyon Phase III, upgrades to production, distribution and transmission facilities, decommissioning activities, information systems, and system maintenance work. Termination of these agreements could result in cancellation charges.

Electricity purchases and Capacity contracts—PGE has power purchase contracts with counterparties, which expire at varying dates through 2035, and power capacity contracts through 2016. As of December 31, 2009, PGE has power sale contracts with counterparties of approximately $78 million in 2010, $5 million in 2011, and $4 million in 2012.

PGE has two long-term power exchange contracts. One exchange contract is with a summer-peaking California utility to help meet the Company's winter-peaking power requirements and expires in 2012. As of December 31, 2009, PGE was owed 230 MWh of electricity, all of which is expected to be delivered by the end of February 2010. The other exchange contract is with a winter-peaking Northwest utility to help meet the Company's summer-peaking power requirements and expires in 2011. As of December 31, 2009, PGE owed 8,414 MWh of electricity, all of which is expected to be delivered by the end of February 2010.

Public Utility Districts—PGE has long-term power purchase contracts with certain public utility districts in the state of Washington and with the City of Portland, Oregon. The Company is required to pay its proportionate share of the operating and debt service costs of the hydroelectric projects whether or not they are operable. Selected information regarding these projects is summarized as follows (dollars in millions):

	Revenue Bonds as of December 31, 2009	PGE Share		Contract Expiration	PGE Cost, including Debt Service		
		Output	Capacity (in MW)		2009	2008	2007
Rocky Reach	$333	12.0%	156	2011	$ 8	$ 9	$ 9
Priest Rapids and Wanapum	649	11.5	233	2052	17	14	13
Wells	176	19.4	159	2018	8	8	8
Portland Hydro	15	100.0	36	2017	4	3	4

Under contracts with the public utility districts, PGE has acquired a percentage of the output (Allocation) of Rocky Reach, Priest Rapids and Wanapum, and Wells. The contracts provide that, should any other purchaser of output default on payments as a result of bankruptcy or insolvency, PGE would be allocated a pro rata share of the output and operating and debt service costs of the defaulting purchaser. For Rocky Reach and Wells, PGE would be allocated up to a cumulative maximum of 25% of the defaulting purchaser's percentage Allocation. For Priest Rapids and Wanapum, PGE would be allocated up to a cumulative maximum that would not adversely affect the tax exempt status of any outstanding debt.

As the individual contracts related to Priest Rapids and Wanapum expired, the terms governing the output of each hydroelectric project are included in one long-term power purchase agreement. Effective November 1, 2009, the last separate contract expired, resulting in both hydroelectric projects being included in one contract. As a result, the debt service amounts previously reported for 2008 and 2007 for Priest Rapids and Wanapum separately were combined to conform with the 2009 presentation.

Natural gas—PGE has agreements for the purchase and transportation of natural gas from domestic and Canadian sources for its natural gas-fired generating facilities. The Company also has a natural gas storage agreement, which expires April 2017, for the purpose of fueling the Company's Port Westward and Beaver generating plants.

Coal and transportation—PGE has coal and related rail transportation agreements with take-or-pay provisions, which expire at various dates through 2013.

Operating leases—PGE has various operating leases associated with its headquarters and certain of its production, transmission, and support facilities. The majority of the future minimum operating lease payments presented in the table above consist of (1) the corporate headquarters lease, which expires in 2018, but includes renewal period options through 2043, and (2) the Port of St. Helens land lease, where PGE's Beaver and Port Westward generating plants operate, which expires in 2096. Rent expense was $8 million in 2009, 2008, and 2007.

The future minimum operating lease payments presented is net of sublease income of $3 million in 2010 and 2011, $2 million in 2012, and $1 million in 2013 and 2014. Sublease income is classified as Miscellaneous income in the consolidated statements of income and was $3 million in 2009, 2008, and 2007.

Guarantees

PGE entered into a sale transaction in 1985 in which it sold an undivided 15% interest in Boardman and a 10.714% undivided interest in the Pacific Northwest Intertie (Intertie) transmission line (jointly the Boardman Assets) to an unrelated third party (Purchaser). The Purchaser leased the Boardman Assets to a lessee (Lessee) unrelated to PGE or the Purchaser. Concurrently, PGE assigned to the Lessee certain agreements for the sale of power and transmission services from Boardman and the Intertie (P&T Agreements) to a regulated electric utility (Utility) unrelated to PGE, the Purchaser, or the Lessee. The P&T Agreements expire on December 31, 2013. The payments by the Utility under the P&T Agreements exceed the payments to be made by the Lessee to the Purchaser under the lease. In exchange for PGE undertaking certain obligations of the Lessee under the lease, the Lessee reassigned to PGE certain rights, including the excess payments, under the P&T Agreements. However, in the event that the Utility defaults on the payments it owes under the P&T Agreements, PGE may be required to pay the damages owed by the Lessee to the Purchaser under the lease. Assuming no recovery from the Utility and no reduction in damages from mitigating sales or leases related to the Boardman Assets and P&T Agreements, the maximum amount that would be owed by PGE in 2010 is approximately $125 million. Management believes that circumstances that could result in such amount, or any lesser amount, being owed by the Company are remote.

PGE enters into financial agreements and power purchase and sale agreements that include indemnification provisions relating to certain claims or liabilities that may arise relating to the transactions contemplated by these agreements. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and therefore, the overall maximum amount of the obligation under such indemnifications cannot be reasonably estimated. PGE periodically evaluates the likelihood of incurring costs under such indemnities based on PGE's historical experience and the evaluation of the specific indemnities. As of December 31, 2009, management believes the likelihood is remote that PGE would be required to perform or otherwise incur any significant losses with respect to such indemnities. The Company has not recorded any liability on the consolidated balance sheets with respect to these indemnifications.

NOTE 16: VARIABLE INTEREST ENTITIES

PGE has determined that its interest in two VIEs, as outlined below, will absorb the majority of the expected variability generated by the entities. Accordingly, the VIEs are consolidated with the Company's consolidated financial statements. SunWay 1, LLC (SunWay 1) and SunWay 2, LLC (SunWay 2) (or collectively, LLCs) were formed in late 2008 for the sole purpose of designing, developing, constructing, owning, maintaining, operating and financing photovoltaic solar power facilities located on real property owned by third parties and selling the energy generated by the facilities. These facilities can generate up to an aggregate of 1.2 MW of electricity.

PGE is the Managing Member in each of the LLCs, representing less than 1% equity interest in each entity, and a financial institution is the Investor Member, representing more than 99% equity interest in each entity. PGE operates and manages the LLCs pursuant to an operating agreement, which provides PGE with decision making authority without substantive kick-out rights. The operating agreements also provide for the flip of ownership interests upon the culmination of certain events, one of which is the passing of five years. Following the flip, PGE will own 95% of the respective LLCs and the Investor Member will own 5%, without the exchange of any additional consideration. PGE expects to purchase the residual 5% interest from the Investor Member at the then fair market value of the Investor Member's interest.

Determining whether PGE is the primary beneficiary of a VIE is complex, subjective and requires the use of judgments and assumptions. Significant judgments and assumptions made by PGE in determining it is the primary beneficiary of these LLCs include the following: (1) based on projections prepared in accordance with the operating agreement, PGE will absorb a majority of the expected losses of the LLCs; (2) PGE expects to own 100% of the LLCs shortly after five years have lapsed, at which time the facilities will have approximately 75% of their estimated useful life remaining; and (3) PGE has the expertise to own and operate electric generating facilities and is authorized to operate the LLCs pursuant to the operating agreements.

PGE's consolidated financial statements as of and for the years ended December 31, 2009 and 2008 reflect the consolidation of SunWay 1 and SunWay 2.

During 2009, impairment losses of $5 million, which are classified in Depreciation and amortization expense, were recognized on the photovoltaic solar power facilities held by the LLCs. Based on PGE's intent to ultimately acquire 100% of the LLCs and the fact that the capitalized cost of the photovoltaic solar power facilities exceeded the undiscounted cash flows of the facilities over their estimated useful lives, an impairment analysis was performed at the time each facility was completed. Immediately following the completion of the photovoltaic solar power facilities, impairment losses were recognized on these assets. The impairment losses were equal to the excess of the carrying amount over the estimated fair value of these photovoltaic solar power facilities. Estimated fair value was determined using the discounted cash flow method, assuming a discount rate (after taxes) of approximately 7%, which is PGE's allowed rate of return, and estimated useful life of 20 to 25 years. The new cost basis of these photovoltaic solar power facilities is amortized over their remaining estimated useful lives. The valuation technique used to measure fair value of the photovoltaic solar power facilities at the impairment date is considered Level 3 in the fair value hierarchy, as described in Note 4.

As described above, PGE has consolidated the LLCs even though it has less than a 1% ownership interest in the LLCs. The participating members are allocated their share of the LLCs net losses based on the respective members' ownership percentage. Accordingly, the majority of the impairment losses are attributable to the "noncontrolling interests" through the Net losses attributable to noncontrolling interests in PGE's consolidated statement of income for the year ended December 31, 2009.

There are no restrictions on SunWay 1 and SunWay 2's assets included in PGE's consolidated balance sheet as of December 31, 2009 and 2008, with the carrying amounts of those assets totaling $6.9 million and $8.8 million, respectively, substantially all of which are classified as Electric utility plant, net. As of December 31, 2009, SunWay 1 and SunWay 2's total liabilities were nominal, while as of December 31, 2008 they amounted to $8.5 million, substantially all of which were classified as Short-term debt in PGE's consolidated balance sheet as of December 31, 2008.

NOTE 17: JOINTLY-OWNED PLANT

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

As of December 31, 2009, PGE had the following investments in jointly-owned plant (dollars in millions):

	PGE Share	In-service Date	Plant In-service	Accumulated Depreciation (1)	Construction Work In Progress
Boardman	65.00%	1980	$ 434	$274	$ 5
Colstrip	20.00%	1986	494	315	3
Pelton/Round Butte	66.67%	1958/1964	131	49	84
Total			$1,059	$638	$92

(1) Excludes asset retirement obligations and accumulated asset retirement removal costs.

NOTE 18: CONTINGENCIES

Legal Matters

Trojan Investment Recovery

Background. In 1993, PGE closed the Trojan Nuclear Plant as part of the Company's least cost planning process. PGE sought full recovery of, and a rate of return on, its Trojan plant costs in a general rate case filing with the OPUC. In 1995, the OPUC issued a general rate order that granted the Company recovery of, and a rate of return on, 87% of its remaining investment in Trojan plant costs.

Court Proceedings on OPUC Authority to Grant Recovery of Return on Trojan Investment. Numerous challenges, appeals and reviews were subsequently filed in the Marion County Circuit Court (Circuit Court), the Oregon Court of Appeals, and the Oregon Supreme Court on the issue of the OPUC's authority under Oregon law to grant recovery of, and a return on, the Trojan investment. The primary plaintiffs in the litigation were the Citizens' Utility Board (CUB) and the Utility Reform Project (URP). The Oregon Court of Appeals issued an opinion in 1998, which upheld the OPUC's authorization of PGE's recovery of the Trojan investment, but stated that the OPUC did not have the authority to allow PGE to recover a return on the Trojan investment and remanded the case to the OPUC.

Settlement of Court Proceedings on OPUC Authority. In 2000, PGE, CUB, and the staff of the OPUC entered into agreements to settle the litigation related to PGE's recovery of, and return on, its investment in the Trojan plant. The URP did not participate in the settlement, which was approved by the OPUC in September 2000. The settlement allowed PGE to remove from its balance sheet the remaining before-tax investment in Trojan of approximately $180 million at September 30, 2000, along with several largely offsetting regulatory liabilities.

Challenge to Settlement of Court Proceeding. The URP filed a complaint with the OPUC challenging the settlement agreements and the OPUC's September 2000 order. In March 2002, the OPUC issued an order (2002 Order) denying all of the URP's challenges, and approving the accounting and ratemaking elements of the 2000 settlement. On October 10, 2007, following several appeals by various parties, the Oregon Court of Appeals issued an opinion that remanded the 2002 Order to the OPUC for reconsideration.

Remand of 2002 Order. As a result of the Oregon Court of Appeals remand of the 2002 Order, the OPUC considered whether the OPUC has authority to engage in retroactive ratemaking and what prices would have been if, in 1995, the OPUC had interpreted the law to prohibit a return on the Trojan investment. On September 30, 2008, the OPUC issued an order that requires PGE to refund $15.4 million, plus interest at 9.6% from September 30, 2000, to customers who received service from PGE during the period October 1, 2000 to September 30, 2001. The order also provides that the total refund amount will accrue interest at 9.6% from

October 1, 2008 until all refunds are issued to customers. The URP and the plaintiffs in the class actions described below have separately appealed the order to the Oregon Court of Appeals.

The $15.4 million amount, plus accrued interest, resulted in a total refund of $33.1 million as of September 30, 2008. As a result of the September 30, 2008 order, PGE recorded, as a regulatory liability, the total refund due to customers of $33.1 million, which reduced 2008 revenues. As of December 31, 2009, the Company had substantially completed the distribution of the refund.

Class Actions. In a separate legal proceeding, two class action suits were filed in Circuit Court against PGE on January 17, 2003 on behalf of two classes of electric service customers (the Class Action Plaintiffs). The cases seek to represent PGE customers during the period from April 1, 1995 to October 1, 2000. The suits seek damages of $260 million plus interest as a result of the inclusion of a return on investment of Trojan in the prices PGE charged its customers.

On December 14, 2004, the judge granted the Class Action Plaintiffs' motion for Class Certification and Partial Summary Judgment and denied PGE's motion for Summary Judgment. On March 3, 2005 and March 29, 2005, PGE filed two Petitions for an Alternative Writ of Mandamus 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.

On August 31, 2006, the Oregon Supreme Court issued a ruling on PGE's Petitions for Alternative Writ of Mandamus, abating the class action proceedings until the OPUC responded with respect to the 2002 Order (described above). The Oregon Supreme Court concluded that the OPUC has primary jurisdiction to determine what, if any, remedy it can offer to PGE customers, through price reductions or refunds, for any amount of return on the Trojan investment PGE collected in prices for the period from April 1, 1995 through October 1, 2000. The Oregon Supreme Court further stated that if the OPUC determined that it can provide a remedy to PGE's customers, then the class action proceedings may become moot in whole or in part. The Oregon Supreme Court further stated that, if the OPUC determined that it cannot provide a remedy, the court system may have a role to play. The Oregon Supreme Court also ruled that the plaintiffs retain the right to return to the Circuit Court for disposition of whatever issues remain unresolved from the remanded OPUC proceedings.

On October 5, 2006, the Circuit Court issued an Order of Abatement in response to the ruling of the Oregon Supreme Court, abating the class actions, but inviting motions to lift the abatement after one year. On October 17, 2007, the plaintiffs filed a motion to lift the abatement. On February 10, 2009, the Circuit Court judge denied the plaintiffs' motion to lift the abatement.

Management cannot predict the ultimate outcome of the above matters. However, it believes that these matters will not have a material adverse impact on the financial condition of the Company, but may have a material adverse impact on the results of operations and cash flows for a future reporting period.

Complaint and Application for Deferral—Income Taxes

On October 5, 2005, the URP and another party (together, the Complainants) filed a Complaint and an Application for Deferred Accounting with the OPUC alleging that, since the September 2, 2005 effective date of Oregon Senate Bill 408 (SB 408), PGE's rates were not just and reasonable and were in violation of SB 408 because they contained approximately $92.6 million in annual charges for state and federal income taxes that are not being paid to any governmental entity. The Complaint and Application for Deferred Accounting requested that the OPUC order the creation of a deferred account for all amounts charged to customers since September 2, 2005 for state and federal income taxes, less amounts actually paid by or on behalf of PGE to the federal and state governments for income taxes.

On August 14, 2007, the OPUC issued an order granting the Application for Deferred Accounting for the period from October 5, 2005 through December 31, 2005 (Deferral Period). The OPUC's order also dismissed the Complaint, without prejudice, on grounds that it was superfluous to the Complainants' request for deferred accounting. The order required that PGE calculate the amounts applicable to the Deferral Period, along with calculations of PGE's earnings and the effect of the deferral on the Company's return on equity. The order also provided that the OPUC would review PGE's earnings at the time it considered amortization of the deferral.

On December 1, 2007, PGE filed its report as required by the OPUC. In the report, PGE determined that (i) the amount of any deferral would be between zero and $26.6 million; and (ii) PGE's earnings over the twelve-month period ended September 30, 2006 would preclude any refund.

On August 18, 2009, the OPUC issued an order that denied amortization of any deferral in this matter, based on a review of PGE's earnings over the 12-month period ended September 30, 2006. On October 16, 2009, plaintiffs filed an appeal of the August 18, 2009 order with the Oregon Court of Appeals.

Management cannot predict the ultimate outcome of this matter. However, management believes this matter will not have a material adverse effect on PGE's financial condition, results of operations or cash flows.

Turlock Irrigation District Claim

PGE and Power Resources Cooperative (PRC) are parties to an Ownership and Operation Agreement (OOA), pursuant to which PRC is entitled to ten percent of the power generated at Boardman. In 1992, PRC entered into a power purchase agreement with Turlock Irrigation District (Turlock) in which PRC agreed to provide Turlock with its share of the Boardman output. In October 2005, Boardman experienced an outage that extended into 2006.

Turlock subsequently filed a lawsuit against PGE in Multnomah County Circuit Court in the state of Oregon, alleging breach of contract, negligence, and gross negligence, seeking damages in excess of $15 million as a result of having to purchase power in the open market to replace lost output from Boardman during the outage. The complaint further alleges that PRC assigned its litigation rights relating to the outage to Turlock pursuant to an assignment agreement executed in 2007.

PGE sought and received an order joining PRC as a necessary party to the litigation in view of PRC's position as a Boardman co-owner and assignor of Turlock's rights. PRC intervened as a plaintiff, also alleging breach of contract and damages in the amount alleged by Turlock, for the purpose of reimbursing Turlock for those expenses. In September 2009, PGE filed a motion for summary judgment, alleging that Turlock lacked standing to bring an action against PGE and that the OOA bars claims based on negligence.

In November 2009, the Court denied PGE's motion for summary judgment and set a trial schedule. In doing so, the court ruled that Turlock has standing to bring a claim against PGE under the OOA, that negligence claims are not barred under the OOA, and that damages based on economic loss are recoverable under a tort claim.

Management cannot predict the outcome of this matter. Management believes that the outcome will not have a material adverse impact on the financial condition of the Company, but may have a material adverse impact on PGE's results of operations and cash flows in future reporting periods.

City of Glendale Claim

In September 1988, PGE and the City of Glendale, California (Glendale) entered into a Long-Term Power Sale and Exchange Agreement (Agreement) pursuant to which Glendale purchases up to 20 MW of firm system capacity from PGE as scheduled by Glendale. The Agreement remains effective until 2012.

In 2005, Glendale disputed the price that PGE had been charging for power under the contract and requested refunds. In addition, Glendale asserted that the closure of Trojan was the equivalent of a sale of a PGE resource, triggering a duty under the Agreement to renegotiate price terms.

On August 25, 2005, PGE filed a complaint in the U.S. District Court for the District of Oregon against Glendale, requesting a declaratory ruling that PGE does not owe Glendale any refunds under the Agreement and that the closure of Trojan was not a "sale" requiring PGE to renegotiate price terms with Glendale.

In response to PGE's complaint, Glendale asserted that the FERC had jurisdiction over the matter and requested that the FERC direct PGE to adjust the prices under the Agreement and refund to Glendale approximately $23.3 million plus interest. On December 19, 2005, the FERC dismissed the proceeding. Following dismissal of the FERC proceeding, Glendale filed a motion in the District Court case to dismiss PGE's complaint. The Court denied Glendale's motion. Glendale then filed an answer and counterclaim against PGE seeking approximately $23.3 million, plus interest. Subsequently, each party filed a motion for summary judgment. In July 2009, the Court granted PGE's motion for summary judgment in substantial part and denied Glendale's motion for summary judgment. As a result of the Court's ruling, the pricing issues relating to Glendale's assertion of a right to a refund under the Agreement remain in the case for trial, but Glendale's claim that the closure of Trojan required a renegotiation of pricing under the Agreement has been dismissed. Until further discovery has been conducted, the Company is unable to estimate the dollar amount that remains at issue in Glendale's refund claim.

Management cannot predict the outcome of this matter. Management believes that the outcome will not have a material adverse impact on the financial condition of the Company, but may have a material adverse impact on PGE's results of operations and cash flows in future reporting periods.

Regulatory Matters

Pacific Northwest Refund Proceeding

On July 25, 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 (Pacific Northwest Refund proceeding). During that period, PGE both sold and purchased electricity in the Pacific Northwest. In September 2001, upon completion of hearings, the appointed administrative law judge issued a recommended order that the claims for refunds be dismissed. In June 2003, the FERC issued an order terminating the proceeding and denying the claims for refunds. Parties appealed various aspects of the FERC order to the U.S. Ninth Circuit Court of Appeals (Ninth Circuit).

On August 24, 2007, the Ninth Circuit issued its decision, concluding that the FERC failed to adequately explain how it considered or examined new evidence showing intentional market manipulation in California and its potential ties to the Pacific Northwest and that the FERC should not have excluded from the Pacific Northwest Refund proceeding purchases of energy made by the California Energy Resources Scheduling (CERS) division in the Pacific Northwest spot market. The Ninth Circuit remanded the case to the FERC to (i) address the new market manipulation evidence in detail and account for it in any future orders regarding the award or denial of refunds in the proceedings, (ii) include sales to CERS in its analysis, and (iii) further consider its refund decision in light of related, intervening opinions of the court. The Ninth Circuit offered no opinion on the FERC's findings based on the record established by the administrative law judge and did not rule on the FERC's ultimate decision to deny refunds. After denying requests for rehearing, the Ninth Circuit on April 16, 2009 issued a mandate giving immediate effect to its August 24, 2007 order remanding the case to the FERC.

Since issuance of the mandate, certain parties proposing refunds have filed pleadings with the FERC suggesting procedures on remand, attempting to initiate new proceedings, and containing additional evidence that they assert shows market-wide manipulation that justifies refunds from early in 2000. Parties opposing refunds, including PGE, have filed various pleadings that contest allegations of market-wide manipulation and urge the FERC to reaffirm, with a more detailed explanation of its consideration of market manipulation claims, its previous decision not to initiate proceedings to order refunds.

On September 4, 2009, various parties, including PGE, filed a petition for a writ of certiorari with the U.S. Supreme Court requesting that the Supreme Court review the decision of the Ninth Circuit in the Pacific Northwest Refund proceeding. In January 2010, the Supreme Court denied the petition for a writ of certiorari.

The settlement between PGE and certain other parties in the California refund case in Docket No. EL00-95, et seq., approved by the FERC on May 17, 2007, resolved all claims as 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 21, 2001, but does not settle potential claims from other market participants relating to transactions in the Pacific Northwest.

Management cannot predict the outcome of the Pacific Northwest Refund proceeding, or whether the FERC will order refunds in this proceeding, and if so, how such refunds would be calculated. Management believes that the outcome will not have a material adverse impact on the financial condition of the Company, but may have a material adverse impact on PGE's results of operations and cash flows in future reporting periods.

FERC Investigation

In May 2008, PGE received a notice of a preliminary non-public investigation from the FERC Division of Investigations concerning PGE's compliance with its Open Access Transmission Tariff. The investigation involves certain issues identified during an audit by FERC staff.

Management cannot predict the final outcome of the investigation or what actions, if any, the FERC will take or require the Company to take. Management believes that the outcome will not have a material adverse impact on the financial condition, results of operations, or cash flows of the Company.

Environmental Matters

Portland Harbor

A 1997 investigation by the U.S. Environmental Protection Agency (EPA) of a segment of the Willamette River known as the Portland Harbor revealed significant contamination of river sediments. The EPA subsequently included this segment on the federal National Priority List pursuant to the federal Comprehensive Environmental Response, Compensation, and Liability Act as a federal Superfund site and listed sixty-nine Potentially Responsible Parties (PRPs). PGE was included among the PRPs as it has historically owned or operated property near the river.

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

On January 22, 2008, PGE received a Section 104(e) Information Request from the EPA requiring the Company to provide information concerning its properties in or near the segment of the river being examined in the RI/FS, as well as several miles beyond that 5.7 mile segment, to which PGE has responded. During 2009, the EPA sent General Notice Letters to 15 additional PRPs.

The EPA will determine the boundaries of the site at the conclusion of the RI/FS in a Record of Decision, now expected in 2012, in which it will document its findings and select a preferred cleanup alternative.

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

The OPUC issued an order authorizing the deferral, for later ratemaking treatment, of incremental investigation and remediation costs related to the Portland Harbor site incurred during the twelve-month period ended March 31, 2009. PGE requested a second twelve-month deferral period beginning April 1, 2009, however subsequently withdrew the request, opting instead to seek recovery of any incurred costs in future rate proceedings. As of December 31, 2009, the Company had not deferred any costs related to Portland Harbor.

Harbor Oil

Harbor Oil, Inc. (Harbor Oil), located in north Portland, was utilized by PGE to process used oil from the Company's power plants and electrical distribution system from at least 1990 until 2003. Harbor Oil continues to be utilized by other entities for the processing of used oil and other lubricants.

In 1974 and 1979, major oil spills occurred at the Harbor Oil site. Elevated levels of contaminants, including metals, pesticides, and polychlorinated biphenyls, have been detected at the site. On September 29, 2003, the Harbor Oil facility was included on the National Priority List as a federal Superfund site.

PGE received a Special Notice Letter for RI/FS from the EPA, dated June 27, 2005, in which the Company was named as one of fourteen PRPs with respect to the Harbor Oil site. On May 31, 2007, an Administrative Order on Consent was signed by the EPA and six other parties, including PGE, to implement an RI/FS at the Harbor Oil site. The EPA has approved an RI/FS work plan. On-site sampling commenced in 2008 and has yet to be completed.

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

The OPUC issued an order authorizing the deferral, for later ratemaking treatment, of incremental costs related to RI/FS work and any resulting remediation costs incurred in relation to the Harbor Oil site during the twelve-month period ended March 31, 2009. PGE requested a second twelve-month deferral period beginning April 1, 2009, however subsequently withdrew the request, opting instead to seek recovery of any recovery of any incurred costs in future rate proceedings. As of December 31, 2009, the Company had not deferred any costs related to Harbor Oil.

Other Matters

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

QUARTERLY FINANCIAL DATA
(Unaudited)

	Quarter Ended			
	March 31	June 30	September 30	December 31
	(In millions, except per share amounts)			
2009				
Revenues	$ 485	$ 389	$ 445	$ 485
Income from operations (1) (2)	63	45	62	38
Net income (1) (2)	24	26	31	8
Net income attributable to Portland General Electric Company (1) (2)	31	24	32	8
Earnings per share—basic and diluted (1) (2) (3)	0.47	0.31	0.43	0.11
2008				
Revenues (4)	$ 471	$ 425	$ 400	$ 449
Income from operations (4)	63	76	21	57
Net income (4)	28	39	—	20
Net income attributable to Portland General Electric Company (4)	28	39	—	20
Earnings per share—basic and diluted (3)	0.44	0.63	—	0.32

(1) Production and distribution expense for the fourth quarter of 2009 includes costs of $6 million related to the Company's Selective Water Withdrawal project.

(2) Income from operations for the fourth quarter of 2009 includes an $18 million expense related to the write-off of a portion of deferred excess replacement power costs associated with the forced outage of Boardman from November 5, 2005 through February 5, 2006. This resulted in a reduction of $11 million in both Net income and Net income attributable to Portland General Electric Company in the fourth quarter of 2009, reducing earnings per share by $0.14.

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

(4) Revenues for the third quarter of 2008 include the accrual of a refund to customers in the amount of $33.1 million pursuant to an OPUC order issued September 30, 2008 related to the settlement of various Trojan matters, which reduced Net income and Net income attributable to Portland General Electric Company by approximately $20 million.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES.

(a) Disclosure Controls and Procedures

Management of the Company, under the supervision and with the participation of the Chief Executive Officer and the Chief Financial Officer, has evaluated the effectiveness of the Company's disclosure controls and procedures (as such term is defined in Rule 13a-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of the end of the period covered by this report pursuant to Rule 13a-15(b) under the Exchange Act. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of such period, the Company's disclosure controls and procedures are effective in recording, processing, summarizing and reporting, on a timely basis, the information relating to the Company (including its consolidated subsidiaries) required to be disclosed by the Company in the reports that it files or submits under the Exchange Act and are effective in ensuring that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is accumulated and communicated to the Company's management, including the Company's Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

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

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

The Company's internal control over financial reporting includes policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and disposition of the assets; provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures are being made only in accordance with authorizations of management and the directors of the Company; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the Company's financial statements.

Management of the Company, under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the Company's internal control over financial reporting as of the end of the period covered by this report pursuant to Rule 13a-15(c) under the Exchange Act. Management's assessment was based on the framework established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management has concluded that, as of December 31, 2009, the Company's internal control over financial reporting is effective.

The Company's internal control over financial reporting, as of December 31, 2009, has been audited by Deloitte & Touche LLP, the independent registered public accounting firm who audits the Company's consolidated financial statements, as stated in their report included in Item 8.—"Financial Statements and Supplementary Data," which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting, as of December 31, 2009.

(c) Changes in Internal Control over Financial Reporting

There have not been any changes in the Company's internal control over financial reporting during the fourth quarter of 2009 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION.

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

The information required by Item 10 is incorporated herein by reference to the relevant information under the captions "Section 16(a) Beneficial Ownership Reporting Compliance," "Corporate Governance," "Proposal 1: Election of Directors—The Board of Directors," and "Executive Officers" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on May 13, 2010.

The information required to be furnished pursuant to this item with respect to the identification of the Audit Committee, the Audit Committee financial expert, and the Company's code of ethics will be set forth under the caption "Corporate Governance" in the definitive proxy statement and is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION.

The information required by Item 11 is incorporated herein by reference to the relevant information under the captions "Corporate Governance—Non-Employee Director Compensation," "Corporate Governance—Compensation Committee Interlocks and Insider Participation," "Compensation and Human Resources Committee Report," "Compensation Discussion and Analysis," and "Executive Compensation Tables" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on May 13, 2010.

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

The information required by Item 12 is incorporated herein by reference to the relevant information under the captions "Security Ownership of Certain Beneficial Owners, Directors and Executive Officers" and "Equity Compensation Plans," in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on May 13, 2010.

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

The information required by Item 13 is incorporated herein by reference to the relevant information under the caption "Corporate Governance" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held on May 13, 2010.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

The information required by Item 14 is incorporated herein by reference to the relevant information under the captions "Principal Accountant Fees and Services" and "Pre-Approval Policy for Independent Auditor Services" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the SEC in connection with the Annual Meeting of Shareholders scheduled to be held May 13, 2010.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES.

(a) Financial Statements and Schedules

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

(b) Exhibit Listing

Exhibit Number	Description
(3)	**Articles of Incorporation and Bylaws**
3.1*	Second Amended and Restated Articles of Incorporation of Portland General Electric Company (Form 10-Q filed August 3, 2009, Exhibit 3.1).
3.2*	Seventh Amended and Restated Bylaws of Portland General Electric Company (Form 8-K filed February 19, 2010, Exhibit 3.1).
(4)	**Instruments defining the rights of security holders, including indentures**
4.1*	Portland General Electric Company Indenture of Mortgage and Deed of Trust dated July 1, 1945 (Form 8, Amendment No. 1 dated June 14, 1965).
4.2*	Fortieth Supplemental Indenture dated October 1, 1990 (Form 10-K for the year ended December 31, 1990, Exhibit 4) (File No. 1-05532-99).
4.3*	Fifty-sixth Supplemental Indenture dated May 1, 2006 (Form 8-K filed May 25, 2006, Exhibit 4).
4.4*	Fifty-seventh Supplemental Indenture dated December 1, 2006 (Form 8-K filed December 21, 2006, Exhibit 4).
4.5*	Fifty-eighth Supplemental Indenture dated April 1, 2007 (Form 8-K filed April 12, 2007, Exhibit 4).
4.6*	Fifty-ninth Supplemental Indenture dated October 1, 2007 (Form 8-K filed October 5, 2007, Exhibit 4).
4.7*	Sixtieth Supplemental Indenture dated April 1, 2008 (Form 8-K filed April 17, 2008, Exhibit 4.1).
4.8*	Sixty-first Supplemental Indenture dated January 15, 2009 (Form 8-K filed January 16, 2009, Exhibit 4.1).
4.9*	Sixty-second Supplemental Indenture dated April 1, 2009 (Form 8-K filed April 16, 2009, Exhibit 4.1).
4.10*	Sixty-third Supplemental Indenture dated November 3, 2009 (Form 8-K filed November 4, 2009, Exhibit 4.1).
(10)	**Material Contracts**
10.1*	Separation Agreement between Enron Corp. and Portland General Electric Company dated April 3, 2006 (Form 8-K filed April 3, 2006, Exhibit 10.1).
10.2*	Five Year Credit Agreement dated May 27, 2005, between Portland General Electric Company, JP Morgan Chase Bank, N. A., as Administrative Agent, and a group of lenders (Form 8-K filed June 2, 2005, Exhibit 4.1).
10.3*	Credit Agreement dated December 8, 2008, between Portland General Electric Company, Wells Fargo Bank, National Association, as Administrative Agent, and a group of lenders (Form 8-K filed December 10, 2008, Exhibit 4.1).

Exhibit Number	Description
10.4*	Credit Agreement dated December 4, 2009, between Portland General Electric Company, Bank of America N.A., as Administrative Agent, and a group of lenders (Form 8-K filed December 8, 2009, Exhibit 4.1).

Exhibits 10.6 through 10.17 were filed in connection with the Company's 1985 Boardman/Intertie Sale:

10.6*	Long-term Power Sale Agreement dated November 5, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.7*	Long-term Transmission Service Agreement dated November 5, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 001-05532-99).
10.8*	Participation Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.9*	Lease Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.10*	PGE-Lessee Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.11*	Asset Sales Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.12*	Bargain and Sale Deed, Bill of Sale, and Grant of Easements and Licenses dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.13*	Supplemental Bill of Sale dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.14*	Trust Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.15*	Tax Indemnification Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.16*	Trust Indenture, Mortgage and Security Agreement dated December 30, 1985 (Form 10-K for the year ended December 31, 1985, Exhibit 10) (File No. 1-05532).
10.17*	Restated and Amended Trust Indenture, Mortgage and Security Agreement dated February 27, 1986 (Form 10-K for the year ended December 31, 1997, Exhibit 10) (File No. 1-05532).
10.18*	Portland General Electric Company Severance Pay Plan for Executive Employees dated June 15, 2005 (Form 8-K filed June 20, 2005, Exhibit 10.1). +
10.19*	Portland General Electric Company Outplacement Assistance Plan dated June 15, 2005 (Form 8-K filed June 20, 2005, Exhibit 10.2). +
10.20*	Portland General Electric Company 2005 Management Deferred Compensation Plan dated March 4, 2005 (Form 10-K filed March 11, 2005, Exhibit 10). +
10.21*	Portland General Electric Company Management Deferred Compensation Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.1). +
10.22*	Portland General Electric Company Supplemental Executive Retirement Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.2). +
10.23*	Portland General Electric Company Senior Officers' Life Insurance Benefit Plan dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.3). +

Exhibit Number	Description
10.24*	Portland General Electric Company Umbrella Trust for Management dated March 12, 2003 (Form 10-Q filed May 15, 2003, Exhibit 10.4). +
10.25*	Portland General Electric Company 2006 Stock Incentive Plan, as amended (Form 10-K filed February 27, 2008). +
10.26*	Portland General Electric Company 2006 Annual Cash Incentive Master Plan (Form 8-K filed March 17, 2006, Exhibit 10.1). +
10.27*	Portland General Electric Company 2006 Outside Directors' Deferred Compensation Plan (Form 8-K filed May 17, 2006, Exhibit 10.1). +
10.28*	Portland General Electric Company 2008 Annual Cash Incentive Master Plan for Executive Officers (Form 8-K filed February 26, 2008, Exhibit 10.1). +
10.29*	Form of Portland General Electric Company Agreement Concerning Indemnification and Related Matters (Form 8-K filed December 24, 2009, Exhibit 10.1). +
10.30*	Form of Directors' Restricted Stock Unit Agreement (Form 8-K filed July 14, 2006, Exhibit 10.1). +
10.31*	Form of Officers' Performance Stock Unit Agreement (Form 8-K filed March 13, 2008, Exhibit 10.1). +
10.32*	Employment Agreement dated and effective May 6, 2008 between Stephen M. Quennoz and Portland General Electric Company (Form 10-Q filed May 7, 2008, Exhibit 10.3). +
(12)	**Statements Re Computation of Ratios**
12.1	Computation of Ratio of Earnings to Fixed Charges.
(23)	**Consents of Experts and Counsel**
23.1	Consent of Independent Registered Public Accounting Firm Deloitte & Touche LLP.
(31)	**Rule 13a-14(a)/15d-14(a) Certifications**
31.1	Certification of Chief Executive Officer.
31.2	Certification of Chief Financial Officer.
(32)	**Section 1350 Certifications**
32.1	Certifications of Chief Executive Officer and Chief Financial Officer.

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

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

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* Incorporated by reference as indicated.

\+ Indicates a management contract or compensatory plan or arrangement.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on February 24, 2010.

PORTLAND GENERAL ELECTRIC COMPANY

By: /s/ JAMES J. PIRO

James J. Piro
Chief Executive Officer and President

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated on February 24, 2010.

Signature	Title
/s/ JAMES J. PIRO **James J. Piro**	*Chief Executive Officer, President and Director* (principal executive officer)
/s/ MARIA M. POPE **Maria M. Pope**	*Senior Vice President, Finance, Chief Financial Officer and Treasurer* (principal financial and accounting officer)
/s/ JOHN W. BALLANTINE **John W. Ballantine**	*Director*
/s/ RODNEY L. BROWN, JR. **Rodney L. Brown, Jr.**	*Director*
/s/ DAVID A. DIETZLER **David A. Dietzler**	*Director*
/s/ KIRBY A. DYESS **Kirby A. Dyess**	*Director*
/s/ PEGGY Y. FOWLER **Peggy Y. Fowler**	*Director*
/s/ MARK B. GANZ **Mark B. Ganz**	*Director*
/s/ CORBIN A. MCNEILL, JR. **Corbin A. McNeill, Jr.**	*Director*
/s/ NEIL J. NELSON **Neil J. Nelson**	*Director*
/s/ M. LEE PELTON **M. Lee Pelton**	*Director*
/s/ ROBERT T.F. REID **Robert T.F. Reid**	*Director*

EXHIBIT 12.1

PORTLAND GENERAL ELECTRIC COMPANY
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES

	Years Ended December 31,				
	2009	2008	2007	2006	2005
	(Dollars in thousands)				
Income from continuing operations before income taxes	$131,636	$121,825	$220,123	$107,240	$105,759
Total fixed charges	129,948	111,589	98,682	91,846	85,330
Total earnings	$261,584	$233,414	$318,805	$199,086	$191,089
Fixed charges:					
Interest expense	$103,389	$ 90,257	$ 74,362	$ 68,932	$ 68,359
Capitalized interest	11,816	6,184	9,596	8,482	3,717
Interest on long-term power contracts (PUDs)	10,038	10,010	9,552	9,927	8,634
Estimated interest factor in rental expense	4,705	5,138	5,172	4,505	4,620
Total fixed charges	$129,948	$111,589	$ 98,682	$ 91,846	$ 85,330
Ratio of earnings to fixed charges	2.01	2.09	3.23	2.17	2.24

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-143472 on Form S-3 and Registration Statement Nos. 333-142694, 333-135726, and 333-158059 on Form S-8 of our report dated February 24, 2010, relating to the consolidated financial statements of Portland General Electric Company, and the effectiveness of Portland General Electric Company's internal control over financial reporting, appearing in this Annual Report on Form 10-K of Portland General Electric Company for the year ended December 31, 2009.

/s/ DELOITTE & TOUCHE LLP

Portland, Oregon
February 24, 2010

EXHIBIT 31.1

CERTIFICATION

I, James J. Piro, certify that:

1. I have reviewed this Annual Report on Form 10-K of Portland General Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2010

/s/ JAMES J. PIRO

James J. Piro
Chief Executive Officer and President

EXHIBIT 31.2

CERTIFICATION

I, Maria M. Pope, certify that:

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

Date: February 24, 2010

/s/ MARIA M. POPE

Maria M. Pope
Senior Vice President, Finance, Chief Financial Officer, and Treasurer

EXHIBIT 32.1

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

We, James J. Piro, Chief Executive Officer and President, and Maria M. Pope, Senior Vice President, Finance, Chief Financial Officer, and Treasurer, of Portland General Electric Company (the "Company"), hereby certify that the Company's Annual Report on Form 10-K for the year ended December 31, 2009, as filed with the Securities and Exchange Commission on the date hereof pursuant to Section 13(a) of the Securities Exchange Act of 1934 (the "Report"), fully complies with the requirements of that section.

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

/s/ JAMES J. PIRO	/s/ MARIA M. POPE
James J. Piro	**Maria M. Pope**
Chief Executive Officer and President	*Senior Vice President, Finance, Chief Financial Officer, and Treasurer*
Date: February 24, 2010	Date: February 24, 2010

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2009 Accomplishments

2009 was marked by many accomplishments for Portland General Electric. Here are a few of the highlights.

450 megawatts
Total installed capacity of the 217 turbines at the Biglow Canyon Wind Farm once all three phases of the approximate $1 billion project are completed

450,000
Number of smart meters installed in our operating area

$696 million
Capital expenditures of which $214 million was invested in system upgrades on transmission, distribution, and existing generation

Top 10
Ranked by the Solar Electric Power Association as a utility leader in the integration of solar power into its generation portfolio

72,814
Number of customers signed up for our renewable power programs

2009 Solar Business Achievement Award
Recognized by the Solar Electric Power Association in the category of Partnering for Success for being the first utility in the nation to develop a unique third-party ownership model to develop large-scale solar projects in its service area

20
Number of electric vehicle plug-in stations installed in the Portland and Salem areas to help Oregon drivers be more sustainable

55,000
PGE employee volunteer hours

815,739
Total number of customers at the close of 2009, an increase of approximately 1%

3,949 megawatts
PGE's all-time "summer peak" of 3,949 MW, driven by unusually warm weather, occurred in July

No. 1
For the fourth year in a row, PGE sold more renewable power to residential customers than any other utility in the United States

$1.6 million
Amount contributed to the community through PGE's Employee Giving Campaign

Corporate Information

Board of Directors

Corbin A. McNeill, Jr.
Chairman of the Board of Directors,
Portland General Electric;
Retired Chairman and co-CEO,
Exelon Corporation

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

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

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

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

Kirby A. Dyess
Principal,
Austin Capital Management LLC

Peggy Y. Fowler
Retired Chief Executive Officer
and President,
Portland General Electric

Mark B. Ganz
President and Chief Executive Officer,
The Regence Group

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

M. Lee Pelton
President,
Willamette University

Robert T. F. Reid
Retired Chair and Corporate Director,
British Columbia
Transmission Corporation

Corporate Officers

James J. Piro
President and Chief Executive Officer

Stephen R. Hawke
Senior Vice President,
Customer Service and Delivery

Maria M. Pope
Senior Vice President, Finance,
Chief Financial Officer and Treasurer

Arleen N. Barnett
Vice President, Administration

O. Bruce Carpenter
Vice President, Transmission and
Distribution Services

Carol A. Dillin
Vice President, Customers and
Economic Development

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

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

James F. Lobdell
Vice President, Power Operations
and Resource Strategy

Joe A. McArthur
Vice President, Transmission

William O. Nicholson
Vice President, Distribution

W. David Robertson
Vice President, Public Policy

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

Investor Information

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

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

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

Form 10-K
A copy of the company's Form 10-K as filed with the Securities and Exchange Commission (SEC) is contained herein and may be obtained without charge by calling or writing Investor Relations at the company's headquarters.

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

To vote online visit:
Investors.PortlandGeneral.com

Mixed Sources
Product group from well-managed forests, controlled sources and recycled wood or fiber
www.fsc.org Cert no. SCS-COC-000648
© 1996 Forest Stewardship Council

Printed on recycled paper containing at least 10 percent post-consumer recycled content

Design: Michael Patrick Partners Portland & Palo Alto

Portland General Electric

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