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, 2006
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
(Address of principal executive offices) (zip code)
Registrant's telephone number, including area code: **(503) 464-8000**

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

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

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

Title of class
Portland General Electric Company 7.75% Series, Cumulative Preferred Stock, no par value

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K 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, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☐ Accelerated filer ☒ Non-accelerated filer ☐

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

The aggregate market value of the voting stock held by non-affiliates of Portland General Electric Company, computed by reference to the price at which the common stock was last sold, as of the last business day of Portland General Electric Company's most recently completed second fiscal quarter was approximately $694,391,829. The number of shares of Portland General Electric Company's common stock outstanding at February 28, 2007 was 62,504,767 shares.

<u>Documents Incorporated by Reference</u>

Part III, Items 10 - 14	Portions of Portland General Electric Company's definitive proxy statement to be filed pursuant to Regulation 14A for the 2007 Annual Meeting of Shareholders to be held on May 2, 2007.

DEFINITIONS

The following abbreviations or acronyms used in the text and notes to the financial statements are defined below:

Abbreviations or Acronyms	
AFDC	Allowance For Funds Used During Construction
Bankruptcy Court	United States Bankruptcy Court for the Southern District of New York
Beaver	Beaver Combustion Turbine Plant
Boardman	Boardman Coal Plant
BPA	Bonneville Power Administration
Chapter 11 Plan	Fifth Amended Joint Plan of Affiliated Debtors Pursuant to Chapter 11 of the United States Bankruptcy Code, dated January 9, 2004 and as thereafter amended and supplemented from time to time
Colstrip	Colstrip Units 3 and 4 Coal Plant
Coyote Springs	Coyote Springs Unit 1 Generating Plant
CUB	Citizens' Utility Board
Debtors	Enron Corp. and its reorganized debtor subsidiaries under the Chapter 11 Plan
DCR	Disputed Claims Reserve
DEQ	Oregon Department of Environmental Quality
Dth	Decatherm = 10 therms = 1,000 cubic feet of natural gas
EFSC	Energy Facility Siting Council
EITF	Emerging Issues Task Force of the Financial Accounting Standards Board
Enron	Enron Corp., as reorganized debtor pursuant to its Supplemental Modified Fifth Amended Joint Plan of Affiliated Debtors Pursuant to Chapter 11 of the Bankruptcy Code, confirmed by the United States Bankruptcy Court For The Southern District of New York (Case No. 01-16034) on July 15, 2004 and effective November 17, 2004
EPA	U.S. Environmental Protection Agency
ERISA	Employee Retirement Income Security Act of 1974
ESA	Endangered Species Act
ESS	Electricity Service Supplier
FERC	Federal Energy Regulatory Commission
Financial Statements	Consolidated Financial Statements of Portland General Electric Company included in Part II, Item 8 of this report
kWh	Kilowatt-hour

DEFINITIONS

Abbreviations or Acronyms

MW	Megawatt
MWa	Average megawatts
MWh	Megawatt-hour
NRC	Nuclear Regulatory Commission
OPUC	Public Utility Commission of Oregon
SB 408	Oregon Senate Bill 408
PGE or the Company	Portland General Electric Company
Port Westward	Port Westward Power Plant
RVM	Resource Valuation Mechanism
SEC	Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards (issued by the Financial Accounting Standards Board)
Trojan	Trojan Nuclear Plant
URP	Utility Reform Project
USDOE	United States Department of Energy

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Part I

Item 1. Business

General

Portland General Electric Company (PGE, or the Company), incorporated in 1930, is a single, integrated electric utility engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the State of Oregon. PGE also sells electricity and natural gas in the wholesale market to utilities and energy marketers in the western United States. 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 service area is located entirely within Oregon and 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. PGE estimates that at the end of 2006 its service area population was approximately 1.6 million, comprising about 43% of the state's population. The Company added approximately 13,000 retail customers during 2006, and at December 31, 2006 served approximately 793,000 retail customers.

On July 2, 1997, Portland General Corporation, the former parent of PGE, merged with Enron Corp., with Enron continuing in existence as the surviving corporation and PGE operating as a wholly owned subsidiary of Enron. On December 2, 2001, Enron, along with certain of its subsidiaries, filed to initiate bankruptcy proceedings under Chapter 11 of the federal Bankruptcy Code. PGE was not included in the filing.

In accordance with Enron's Chapter 11 Plan, on April 3, 2006 the 42.8 million shares of PGE common stock held by Enron were cancelled and PGE issued 62.5 million shares (of 80 million, no par value, shares authorized) of new PGE common stock. Approximately 27 million shares of the new PGE common stock were initially issued to the Debtors' creditors holding allowed claims, and approximately 35.5 million shares were issued to a Disputed Claims Reserve (DCR), where the shares will be held to be released over time to the Debtors' creditors holding allowed claims, in accordance with the Chapter 11 Plan. Distributions are generally scheduled for April and October of each year. Since the initial distribution, approximately 3.5 million shares of PGE common stock have been released from the DCR, with approximately 32 million shares held in the DCR as of February 1, 2007. Following issuance of the new PGE common stock, PGE ceased to be a subsidiary of Enron. The new PGE common stock is listed on the New York Stock Exchange under the ticker symbol POR. For further information, see "Ownership of PGE" in Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operation."

As of December 31, 2006, PGE had 2,635 employees. This compares to 2,620 and 2,644 employees at December 31, 2005 and 2004, respectively. A total of 858 employees are covered under agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 829 employees for a five-year period effective from March 1, 2004 through February 28, 2009. In addition, 29 employees (13 at Coyote Springs and 16 at Port Westward) are currently covered under an agreement that began on September 1, 2001, with a new agreement, effective from March 17, 2007 through March 16, 2012, pending ratification.

Available Information

The Company's annual report 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 or may be accessed free of charge through the Investors section of the Company's website at www.portlandgeneral.com as soon as reasonably practicable after the reports are electronically filed with, or furnished to, the 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.

Customers and Operating Revenues

Retail

PGE serves a diverse retail customer base. Residential, the largest customer class, comprises about 88% of the Company's total number of customers, with the remainder comprised largely of commercial customers. At year-end 2006, PGE served 259 industrial customers. Residential demand is sensitive to the effects of weather, with revenues highest during the winter heating season. Commercial and industrial customer classes are not dominated by any single industry. While the 20 largest customers constitute about 13% of total retail revenues, they represent 9 different commercial and industrial groups, including high technology, paper manufacturing, metal fabrication, health services, and governmental agencies. No single customer represents more than 5% of PGE's total retail load or 4% of total retail revenues.

Wholesale

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. Such participation includes power purchases and sales resulting from economic dispatch decisions for its own generation, which allows PGE to secure reasonably priced power for its customers. Interconnected transmission systems in the western states serve utilities with diverse load requirements, which allows the Company to purchase and sell electricity within the region depending upon the relative price and availability of power, water conditions, and seasonal demand.

Wholesale electricity sales related to activities to serve retail load requirements comprised about 9% and 8% of total operating revenues in 2006 and 2005, respectively. Most 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. These net transactions are also referred to as "book outs." Only the net amount of those purchases or sales required to fulfill retail and wholesale obligations are physically settled.

Other Operating Revenues

Other operating revenues include sales of natural gas in excess of generating plant requirements and revenues from transmission services, pole contact rentals, and certain other electric services to customers.

The following table summarizes PGE's Total Operating Revenues for the years indicated (dollars in millions):

	2006		2005		2004	
	Amount	**%**	**Amount**	**%**	**Amount**	**%**
Operating Revenues						
Retail	$ 1,367	90%	$ 1,305	90%	$ 1,318	91%
Wholesale	135	9%	116	8%	107	7%
Other Operating Revenues	18	1%	25	2%	29	2%
Total Operating Revenues	$ 1,520	100%	$ 1,446	100%	$ 1,454	100%

For further information, including year-to-year comparisons of revenues, energy sales, and number of customers, see Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

Regulation

PGE is subject to the jurisdiction of the Public Utility Commission of Oregon (OPUC), comprised of three members appointed by Oregon's governor to serve non-concurrent four-year terms. The OPUC approves the Company's retail prices and establishes conditions of utility service. The OPUC's obligation under Oregon law is to ensure that the prices and terms of service are fair, non-discriminatory, and provide PGE an opportunity to earn a fair return on its investment. In addition, the OPUC regulates the issuance of stock and long-term debt, prescribes the system of accounts to be kept by Oregon utilities, and reviews applications to sell utility assets and engage in transactions with affiliated companies.

Certain activities of PGE are also subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC). The Company is a "licensee" and a "public utility," as those terms are used in the Federal Power Act, and is subject to regulation by the FERC as to accounting policies and practices, licensing of hydroelectric projects, transmission services, wholesale sales, issuance of short-term debt, and other matters. The Energy Policy Act of 2005, which significantly revised the Federal Power Act and Natural Gas Act, gave the FERC increased authority to implement mandatory transmission and reliability standards as well as enhanced oversight of power and transmission markets, including protection against market manipulation. In addition, PGE's interest in a natural gas pipeline is subject to the FERC's jurisdiction. Under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978, the FERC's authority includes matters related to extension, enlargement, safety, and abandonment of jurisdictional pipeline facilities, as well as transportation rates and accounting for interstate natural gas commerce.

Construction of new generating facilities in Oregon requires a permit from the Energy Facility Siting Council (EFSC).

The Nuclear Regulatory Commission (NRC) regulates the licensing and decommissioning of nuclear power plants. In 1993, the NRC issued a possession-only license amendment to PGE's Trojan operating license, and in early 1996 the NRC and EFSC approved the Trojan Decommissioning Plan, which has allowed PGE to proceed in decommissioning the plant. The NRC approved the completed transfer of spent nuclear fuel from the Trojan spent fuel pool to a separately licensed dry cask storage system that will house the nuclear fuel on the plant site until permanent storage is available. PGE completed the radiological decommissioning of the Trojan site in December 2004 pursuant to an NRC-approved License Termination Plan, with the plant's Facility Operating License terminated by the NRC in May 2005. Spent fuel storage activities will continue to be subject to NRC regulation until all nuclear fuel is removed from the site, decontamination is completed, and the storage installation is fully decommissioned. The Oregon Department of Energy also monitors Trojan. For further information, see "Nuclear Decommissioning" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

Regulatory Matters

Retail Rate Changes

PGE filed a general rate case in March 2006 for consideration by the OPUC. On January 12, 2007, the OPUC issued an order approving an overall price increase of approximately 1.3%. The increase represents the combined effect of a 1.4% decrease related to general costs, which became effective on January 17, 2007, and a 2.8% increase related to cost recovery of Port Westward, to become effective when the plant is placed in service, expected to be in late April 2007. The decrease related to general costs primarily reflects reductions in forecasted test year costs and the effects of decisions regarding the cost of capital. The change in retail prices is based upon a 50% equity capital structure, a 10.1% return on equity, and an overall rate of return of 8.29%.

The OPUC previously authorized a 5.1% average retail price increase, effective on January 1, 2007, under the Resource Valuation Mechanism (RVM) providing price adjustments reflecting annual updates to PGE's forecast of net variable power costs. The OPUC's January 12th order approved a process by which PGE can continue to adjust prices to reflect power cost forecasts for future years. An Annual Power Cost Update Tariff, which replaces the RVM, provides for rate adjustments to reflect updated forecasts of net variable power costs for future calendar years. In addition, a Power Cost Adjustment Mechanism (PCAM) provides for rate adjustments to reflect differences between forecast and actual power costs, with costs and benefits shared with PGE's retail customers. For further information, see "Resource Valuation Mechanism" and "General Rate Case" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

Utility Rate Treatment of Income Taxes

In 2005, the Oregon legislature passed a law that adjusts the way that PGE and other Oregon investor-owned electric and gas utilities recover income tax expense from customers through revenues for utility services. The law, commonly referred to as Oregon Senate Bill 408 (SB 408), 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 utilities or their consolidated group. It requires that utilities file a report with the OPUC each year regarding the amount of taxes paid by the utility or its consolidated group (with certain adjustments), as well as the amount of taxes authorized to be collected in rates, as defined by the statute. This report is to be 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 its rates. The first rate adjustment under the law applies to taxes paid to units of government and amounts collected from customers on or after January 1, 2006.

Based on PGE's assessment of the rules adopted by the OPUC in September 2006 to implement SB 408, the Company has estimated and recorded potential refunds to customers of approximately $42 million (including $2 million in accrued interest) for the year 2006. Any refunds to customers for the 2006 tax year would begin after June 1, 2008. For further information, see "Utility Rate Treatment of Income Taxes" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

Retail Customer Choice Program

Oregon's customer choice program, implemented in 2002 as part of the state's electricity restructuring law, provides all commercial and industrial customers of the two large investor-owned utilities in Oregon direct access to suppliers of electric commodity service other than PGE (Electricity Service Suppliers, or ESSs). In addition, cost-of-service and market price options are offered to these customers. The program further provides for a "transition adjustment" for non-residential customers that choose to purchase energy at market prices from investor-owned utilities or from ESSs. Such charges or credits reflect the above-market or below-market cost, respectively, of energy resources owned or purchased by the utility and are designed to ensure that such costs or benefits do not unfairly shift to the utility's remaining energy customers. Residential and small commercial and industrial 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.

In 2006, the three ESSs registered to transact business with PGE served a total of 25 customers with a total average load of approximately 125 MWa, representing about 8% of PGE's non-residential load and 5% of the Company's total retail load. In addition, a total of 59 commercial and industrial customers were receiving service from PGE under market-based pricing options at the end of 2006. Approximately 50,000 customers have chosen renewable energy options and approximately 1,800 customers have chosen the time-of-use option.

PGE also offers an option by which certain large non-residential customers may, for a minimum three-year or five-year term, elect to be removed from cost-of-service pricing, with energy supplied by an ESS or at a daily market rate by PGE. Two customers, with a total load of approximately 10 MWa, have chosen the five-year option; one began receiving service from PGE in 2003 and the other began receiving service from an ESS in 2004. Three additional customers, with a total load of approximately 145 MWa, have elected to receive service from ESSs beginning in 2007 under the three-year or five-year options. PGE estimates that customers with a total average load of approximately 270 MWa will receive energy from ESSs in 2007. While these “direct access” customers purchase their electricity from other suppliers, PGE continues to deliver energy to these customers and is not adversely impacted financially.

The restructuring law also provides for a 10-year Public Purpose Charge, equal to 3% of retail revenues, designed to fund cost-effective conservation measures, new renewable energy resources, and weatherization measures for low-income housing. In addition, the law provides for low-income electric bill assistance.

In accordance with the restructuring law and an order from the OPUC, PGE deferred certain costs related to implementation of the restructuring plan for recovery in electricity prices. Recovery of these costs is continuing, with unrecovered costs totaling approximately $11 million at December 31, 2006.

PGE continues to operate as a cost-based regulated electric utility, for which revenue requirements are determined based upon the cost to serve customers, including a reasonable rate of return to the Company, and remains obligated to provide full ("bundled") service to all of its customers. PGE's most recent general rate filings with the OPUC, in 2001 and 2006, were both based upon this cost-of-service model. At this time, the large majority of PGE's customers continue to take service under rate tariff schedules determined by the cost of service.

While PGE continues to meet the criteria of Statement of Financial Accounting Standards (SFAS) No. 71, Accounting for the Effect of Certain Types of Regulation, and currently applies its provisions to reflect the effects of rate regulation in its financial statements, the Company periodically assesses the applicability of the statement to its business, or separable portions thereof. These assessments consider both the current and anticipated future rate environment and related accounting guidance, as outlined in SFAS No. 101, Regulated Enterprises - Accounting for the Discontinuation of Application of SFAS No. 71, and Emerging Issues Task Force (EITF) Issue 97-4, Deregulation of the Pricing of Electricity - Issues Related to the Application of SFAS No. 71 and SFAS No. 101.

Integrated Resource Plan

PGE's Integrated Resource Plan (IRP), required by the OPUC, describes the Company's strategy to meet the long-term electric energy needs of its customers, with emphasis on supply reliability, price stability, risk reduction, environmental stewardship, and cost effectiveness. Planning for future resources is guided by PGE's objective to meet its load requirements with supply from its own generating resources (both existing and new) and mid- to long-term power contracts.

PGE has undertaken a process to procure approximately 790 MWa in energy resources (960 MW of capacity), as well as additional capacity resources, as recommended in the Company's Integrated Resource Final Action Plan acknowledged by the OPUC in July 2004.

In accordance with that acknowledgement, the Company has entered into the following power purchase agreements:

- A ten-year purchase agreement for 93 MWa, which began in 2006;
- A thirty-year purchase power agreement for approximately 27 MWa (75 MW capacity) of wind generated power, which began in December 2005;
- Two five-year agreements, consisting of a 25 MW on-peak tolling agreement that began in January 2005, and a power purchase agreement for 25 MWa, which began in late 2006; and,
- Capacity agreements totaling 400 MW, extending from early 2005 to 2011.

PGE's Final Action Plan also included construction of a 350 MWa natural gas-fired plant at the Company's Port Westward site. Construction of the plant began in February 2005 and is expected to go into service in late April 2007. The plant is expected to have a total capacity of approximately 400 MW, including 25 MW from duct firing.

In November 2006, PGE executed an agreement to acquire 76 wind turbines for phase one construction of the Biglow Canyon Wind Farm. The first phase of the project will have a total capacity of 125 MW (48 MWa), with completion expected by December 2007. In combination with an existing wind contract, the Biglow Canyon Wind Farm project will fulfill PGE's 200 MW wind power target contained in the Company's Integrated Resource Final Action Plan.

Other acknowledged actions include:

- Savings of 55 MWa from energy efficiency measures funded by the Energy Trust of Oregon;
- Upgrades to existing plants and contract extensions totaling 60 MWa;
- Acquisition of 30-35 MW of dispatchable standby generation; and,
- Short-term market acquisitions of up to 125 MWa.

The OPUC's 2004 order acknowledging PGE's Integrated Resource Final Action Plan requires that, in addition to specific energy resource acquisitions, the Company address constraints on competitive renewable development in the region, work with the Bonneville Power Administration (BPA) and others to develop transmission access to additional wind (and other) resources at a reasonable price, and demonstrate that the Company has taken measures to acquire, option, or retain cost effective transmission capacity. PGE is actively engaged in regional discussions regarding constraints to competitive renewable development and is evaluating various transmission options that would result in additional capacity.

At the request of the Company, the OPUC agreed that, due to the continuing execution of the current Integrated Resource Final Action Plan, no IRP for the year 2006 would be required. PGE currently plans to file a new IRP with the OPUC in the second quarter of 2007.

Federal Wholesale and Transmission Regulation

In 1998, the FERC granted PGE authority to sell wholesale power at market-based rates. In May 2005, following review of an updated market power analysis submitted by the Company (required of jurisdictional utilities), the FERC granted reauthorization of PGE's market-based rate authority for the period 2005-2008.

In 1999, the FERC issued Order No. 2000 in a continued effort to more efficiently manage transmission, create fair pricing policies, and encourage competition by providing equal access to the nation's electric power grids. The order requires all owners of electricity transmission facilities to file a proposal to join a Regional Transmission Organization or provide reasons that prevent such a filing. In response to this order, the BPA and certain western utilities, including PGE, filed an initial proposal with the FERC to form a regional non-profit transmission organization that would operate the transmission system and manage pricing in the Pacific Northwest and portions of other western states. However, the organization (named Grid West) was dissolved in April 2006 after several major transmission owners elected to withdraw from the organization. As a major transmitting utility, PGE continues to participate in other transmission restructuring efforts to enhance operations of the regional system. The Company will monitor and engage in these efforts, although there remains considerable uncertainty regarding their further development.

In 2005, the Energy Policy Act of 2005 was signed into law. The new law repealed the Public Utility Holding Company Act of 1935 and significantly revised the Federal Power Act and Natural Gas Act. The law gives the FERC increased statutory authority to implement its stated goals, including mandatory transmission and reliability standards and enhanced oversight of power and transmission markets (including protection against market manipulation). The law also enacted tax incentives for the development of renewable and cleaner-fuel electric generating resources and for other electric and gas related purposes and substantially changed the qualifying facility provisions of the Public Utility Regulatory Policies Act of 1978.

City of Portland Investigation

The City of Portland has indicated that it may pursue ratemaking for PGE's retail customers who reside within the City's boundaries. In September 2005, the Portland City Council approved a resolution directing the City Attorney and City staff to obtain from PGE information regarding the collection and payment of utility income taxes. The City of Portland stated that it believes its City Charter provides it with authority for this request. PGE voluntarily provided extensive financial and operational data to the City of Portland. The City of Portland subsequently broadened its inquiry to include PGE's power trading activities in 2000 and 2001 and requested that PGE provide many additional documents and records, and on March 23, 2006 issued a subpoena to PGE seeking numerous records and documents. PGE determined that there are a number of legal and practical issues concerning the City of Portland's subpoena and other requests for additional information, and has declined to provide any additional data to the City of Portland while those issues remain unresolved. On April 21, 2006, PGE filed a complaint in Multnomah County Circuit Court seeking clarity on whether the City of Portland has investigatory and ratemaking authority. The City of Portland has agreed not to seek enforcement of the subpoena while this case is pending.

Retail and Wholesale Competition

General

Restructuring of the electric industry continues to move slowly at both the national level and in the Pacific Northwest. PGE maintains its focus on commitment to service excellence while providing increased choices for its retail customers.

Retail

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 for the residential and commercial space and water heating market, and fuel oil suppliers, which compete primarily for residential space heating customers. In addition, commercial and industrial customers are allowed direct access to competing ESSs in accordance with Oregon's electricity restructuring law, related regulations, and PGE's tariff. PGE currently offers all customers regulated cost-of-service and other pricing options. The Company does not operate as an ESS.

Wholesale

PGE participates in the wholesale energy marketplace in order to manage its power supply risks and acquire the necessary electricity and fuel to meet the needs of its retail customers and administer its current long-term wholesale contracts. The amount of surplus electric generating capability in the western United States, the amount of annual snow pack and its impact on hydro generation, the number and credit quality of wholesale marketers and brokers participating in the energy trading markets, the availability and price of natural gas as well as other fuels, and the availability and pricing of electric and gas transmission all contribute to and have an impact on the wholesale price and availability of electricity. The Company currently has authority under its FERC tariff to charge market-based rates for wholesale energy sales.

Power Supply

To meet its customers' energy needs, PGE relies upon its existing base of generating resources, long-term power contracts, and power and fuel purchases of up to five years in duration that together provide flexibility to respond to consumption changes and Oregon's electricity restructuring law.

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. Current forecasts indicate near normal hydro conditions for 2007.

In addition, natural gas and coal, used to fuel the Company's thermal generating plants, are subject to price volatility. PGE uses natural gas forward, swap, option, and futures contracts to manage its exposure to volatility in natural gas prices and will continue to monitor its exposure to changing prices for coal and natural gas.

For further information, see "Power and Fuel Supply" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

Generating Capability

PGE's existing hydroelectric, coal-fired, and gas-fired plants are important resources for the Company, providing 1,974 MW of generating capability (see Item 2. - "Properties" for a full listing of PGE's generating facilities). The Company's lowest cost generating resources are its five FERC licensed hydroelectric projects that incorporate eight powerhouses on the Clackamas, Sandy, Deschutes, and Willamette rivers in Oregon. For further information, see "Hydro Relicensing" in Item 2. - "Properties".

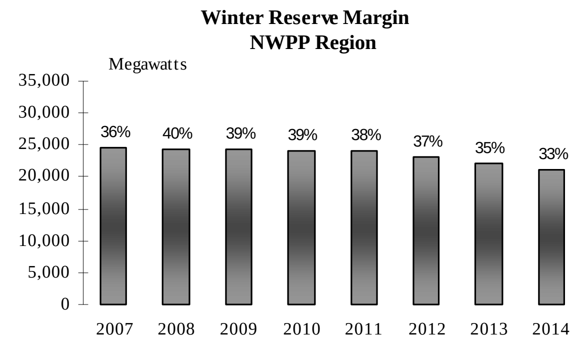
PGE is currently constructing a 400 MW natural gas-fired plant at the Company's Port Westward site. Construction of the plant began in February 2005 and is expected to go into service in late April 2007.

In November 2006, PGE executed an agreement to acquire 76 wind turbines for construction of the first phase of the Biglow Canyon Wind Farm. Each of the turbines will have the capacity to generate 1.65 MW of electricity, for a total of approximately 125 MW. Construction is planned to begin in the first half of 2007, with completion expected by the end of the year.

Purchased Power

PGE supplements its own generation with long-term and short-term wholesale contracts as needed to meet its retail load requirements or provide the most economic mix of resources on a variable cost basis. The Company has long-term power contracts with four hydroelectric projects on the mid-Columbia River, which provide approximately 567 MW of firm capacity. PGE also has firm contracts, ranging from one to thirty years, to purchase 1,175 MWa of power from other counterparties, other Pacific Northwest utilities, and the Confederated Tribes of the Warm Springs Reservation of Oregon, and has a 30-year agreement for 27 MWa of wind capacity with an independent power producer. In addition, PGE has an exchange contract with a summer-peaking California utility to help meet the Company's winter-peaking requirements, and an exchange contract with another Northwest utility to help meet the Company's summer-peaking requirements. These resources, along with short-term contracts, provide the Company with sufficient firm capacity to serve its peak loads. For further information, see "Power and Fuel Supply" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

Regional System Reliability



PGE relies on wholesale market purchases within the Western Electricity Coordinating Council (WECC) in conjunction with its base of generating resources to supply its resource needs and maintain system reliability. The WECC, a regional electric reliability organization, provides coordination for operating and planning a reliable and adequate electric power system for the western continental United States, Canada, and Mexico. It further supports competitive power markets, helps assure open and non-discriminatory transmission access among members, provides a forum for resolving transmission access disputes, and provides an environment for coordinating the operating and planning activities of its members. The WECC area includes 14 western states, with peak loads that occur at different times of the year. Energy loads in California and the Southwest peak in the summer due to air conditioning use, while northern loads peak during winter heating months. According to the WECC's most recently published 10-Year Coordinated Plan Summary, its members, which serve a population of approximately 71 million, will have sufficient capacity margin to meet forecast demand and energy requirements through the year 2014, assuming the timely completion of planned new generation. The Northwest Power Pool (NWPP) area of the WECC, which contains significant hydro generation, is comprised of all or major portions of the states of Oregon, Washington, Idaho, Montana, Nevada, Utah, and Wyoming, and the Canadian provinces of British Columbia and Alberta. According to NWPP forecasts, hourly peak demand and annual energy requirements in the NWPP through 2014 are projected to grow at annual rates of 1.7% and 1.9%, respectively. The ability of the NWPP to meet peak demand is expected to be adequate through 2014. The reserve margins indicated above would be used to cover such items as unplanned outages of generating facilities, changes in the availability of hydro generation for peak use, required operating reserves, and the potential adverse impact of severe weather events on both generating capabilities and retail demand.

The Pacific Northwest peak season historically occurs in the winter, when home and business heating and lighting cause the highest demand. Due to unusually warm weather and increased air conditioning, PGE's 2006 peak load occurred in July. This all-time "summer peak" was 3,706 MW, of which approximately 39% was met through short-term wholesale electricity purchases. PGE's all-time high net system load peak of 4,073 MW occurred in December 1998.

On December 31, 2006, PGE's total firm resource capacity, including short-term purchase agreements, was approximately 4,911 MW (net of short-term sales agreements of 1,081 MW).

Restoration of Salmon Runs

Populations of many salmon species in the Pacific Northwest have shown significant decline over the last several decades. Several of these species have been granted protection under the federal Endangered Species Act (ESA). Long-term recovery plans for these species include major operational changes to the region's hydroelectric projects. The biggest change thus far has been a modification in the timing of stored water releases and a spill program to assist juvenile salmon at the federal dams located in the Columbia River and Snake River basins. The result of these changes has been a loss of some hydroelectric energy generation and seasonal shifting of other hydroelectric generation from the fall and winter periods to the spring and summer periods.

PGE continues to evaluate the impact of current and potential ESA listings on the operation of its hydroelectric projects on the Deschutes, Sandy, Clackamas, and Willamette rivers. The Company's consultation with the National Marine Fisheries Service and the United States Fish and Wildlife Service has identified opportunities for the protection of fish runs on those rivers where PGE operates. ESA consultations on PGE's Clackamas River project, completed by the agencies in 2003, will be in effect until a new license is granted by the FERC. A new FERC license for the Clackamas River Project is currently anticipated by 2009. The Biological Opinion for the Bull Run Project on the Sandy River, received in 2003, will cover the project's operations and decommissioning scheduled for 2007 and 2008.

In 2005, PGE received Biological Opinions and Incidental Take Statements for the Company's Willamette River (Sullivan) and Deschutes River (Pelton Round Butte) projects associated with the issuance of new FERC licenses for these projects. The Biological Opinion and Incidental Take Statement, which provide authorization to licensees for the take of listed species consistent with terms and conditions identified in the consultation, are generally issued at the conclusion of the ESA consultation process associated with obtaining new or amended FERC hydropower licenses.

Fuel Supply

PGE acquires fuel supply contracts to support planned operation of thermal generating plants. Flexibility in contract terms allows for the most economic dispatch of PGE's thermal resources relative to the market price of wholesale power.

Coal

Boardman
PGE has negotiated purchase agreements that provide coal for Boardman's operating requirements through 2008. Available coal supplies are sufficient to meet future requirements of the plant. The coal, obtained from surface mining operations in Wyoming and subject to federal, state, and local regulations, is delivered by rail under two separate 10-year contracts, the terms of which began January 1, 2004. Coal purchases in 2006, totaling 1.9 million tons, contained approximately 0.3% of sulfur by weight. Coal deliveries in 2006 were lower than normal due to an extended outage of Boardman during the first half of the year. Utilizing low sulfur coal, the plant emitted less than the limit allowed by the U.S. Environmental Protection Agency (EPA) of 1.2 pounds of sulfur dioxide (SO_2) per MMBtu.

Colstrip
Coal for Colstrip Units 3 and 4, located in southeastern Montana, is obtained from an adjacent mine under a contract that expires in 2019. The contract requires that the coal not exceed maximum sulfur content of 1.5% by weight. In 2006, actual sulfur content for coal used at Colstrip ranged from approximately 0.68% to 0.81% by weight. Available coal supplies are sufficient to meet future requirements of the plant. Coal purchases for PGE's share of Colstrip Units 3 and 4 totaled 1.4 million tons in 2006. Utilizing wet scrubbers to minimize (SO_2) emissions, the plant operated in compliance with EPA's source-performance standards.

Natural Gas

PGE makes long-term, short-term, and spot market purchases to secure transportation capacity and mid-term, short-term and spot market purchases to secure natural gas supplies sufficient to fuel plant operations. PGE re-markets natural gas and transportation capacity in excess of its needs.

PGE owns 79% of the Kelso-Beaver Pipeline, which directly connects both its Beaver and Port Westward generating plants to Northwest Pipeline, an interstate gas pipeline operating between British Columbia and New Mexico. PGE has been granted a blanket transportation certificate by the FERC that authorizes the Company to transport natural gas for others under a Part 284 blanket transportation certificate.

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.

Beaver and Port Westward

Firm gas supplies for Beaver and Port Westward (expected to go into service in late April 2007) are purchased up to 60 months in advance, based on anticipated operation of the plants. PGE has access to 87,000 Dth/day of firm gas transportation capacity to serve the two plants. In addition, PGE 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 fully meet anticipated requirements of Beaver and Port Westward in 2007.

Coyote Springs

The Coyote Springs generating station utilizes 41,000 Dth/day of firm transportation capacity on three pipeline systems accessing gas fields in Alberta, Canada. Firm gas supplies for Coyote Springs, based on anticipated operation of the plant, are typically purchased up to 60 months in advance. PGE believes that sufficient market supplies of gas are available to fully meet requirements of Coyote Springs in 2007.

Oil

Beaver

The Beaver generating station 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. To ensure the plant's continued operability under such circumstances, PGE had an approximate 12-day supply of oil at the plant site at December 31, 2006.

Coyote Springs

The Coyote Springs plant has the capability to operate on oil, although such capability has been deactivated in order to optimize natural gas operations. Should the plant's oil capability be restored, a fuel storage tank, capable of holding sufficient oil for 50 hours of operation, is available at the plant site.

Environmental Matters

PGE operates in a state recognized for environmental leadership. The Company's policy of environmental stewardship emphasizes minimizing both environmental risk and waste in its operations, along with promoting the wise use of energy.

Regulation

PGE's operations are subject to a wide range of environmental protection laws covering air and water quality, noise, waste disposal, and other environmental issues. The EPA, along with state agencies and departments such as the Oregon Environmental Quality Commission (OEQC), the Oregon Department of Environmental Quality (DEQ), the Oregon Department of Energy, and the EFSC, have direct jurisdiction over environmental matters. Environmental matters regulated by these agencies include the siting and operation of generating facilities and the accumulation, cleanup, and disposal of toxic and hazardous wastes.

Harborton

A 1997 investigation of a portion of the Willamette River known as the Portland Harbor, conducted by the EPA, revealed significant contamination of sediments within the harbor. Subsequently, the EPA has included Portland Harbor on the federal National Priority list pursuant to the federal Comprehensive Environmental Response, Compensation, and Liability Act (Superfund). In 2000, PGE, along with sixty-eight other companies on the Portland Harbor Initial General Notice List, received a "Notice of Potential Liability" with respect to the Portland Harbor Superfund Site. Sufficient information is currently not available to determine either the total cost of investigation and remediation of the Portland Harbor or the liability of Potentially Responsible Parties (PRPs), including PGE. Management believes that the Company's contribution to the sediment contamination, if any, would qualify it as a de minimis PRP.

For further information, see "Environmental Matters" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

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 is also utilized by other entities for the processing of used oil and other lubricants. A 2003 investigation conducted by the EPA revealed elevated levels of contaminants, including metals, pesticides, and polychlorinated biphenyls (PCBs) on the Harbor Oil site. Subsequently, the EPA included Harbor Oil on the federal National Priority List as a federal Superfund site. In 2005, PGE received a Special Notice Letter for Remedial Investigation/Feasibility Study from the EPA, in which the Company was named as one of fourteen PRPs with respect to the Harbor Oil site. PGE, along with other PRPs, is negotiating an Administrative Order of Consent with the EPA to conduct a Remedial Investigation/Feasibility Study. Sufficient information is currently not available to determine either the total cost of investigation and remediation of the Harbor Oil site or the liability of PRPs, including PGE.

For further information, see "Environmental Matters" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

Air Quality

PGE's operations, principally its fossil-fuel electric generation plants, are subject to the federal Clean Air Act (CAA) and other federal regulatory requirements. State governments also monitor and administer certain portions of the CAA and must set standards that are at least equal to federal standards; Oregon's air quality standards exceed federal standards. Primary pollutants addressed by the CAA that affect PGE are SO_2, nitrogen oxides, carbon monoxide, and particulate matter. PGE manages its emissions by the use of low sulfur fuel, emission controls, emission monitoring, and combustion controls. Required operating permits have been obtained for all thermal generating facilities operated by PGE.

The SO_2 emissions allowances awarded under the CAA, along with expected future annual allowances, are sufficient to operate Boardman at a 60% to 67% capacity. PGE has acquired additional emissions allowances, which, in combination with the allowance awards, will allow the operation of the Boardman plant at forecasted capacity for at least the next ten years.

In accordance with new federal regional haze rules, the DEQ is conducting an assessment of emission sources pursuant to a Regional Haze Best Available Retrofit Technology (RH BART) process. Several other states are conducting a similar process. Those sources determined to cause, or contribute to, visibility impairment at protected areas will be subject to an RH BART Determination.

In May 2005, the EPA established the Clean Air Mercury Rule (CAMR), which regulates mercury emissions from the nation's coal-fired electric generating plants. The CAMR includes a federal "cap-and-trade" program (scheduled to begin in 2010), that establishes a cumulative total ("cap") of mercury emissions from all electric generating plants in the United States and assigns to each state a mercury emissions "budget." Individual states had the choice of adopting this model or establishing their own programs.

In December 2006, the OEQC adopted the Utility Mercury Rule, which limits mercury emissions from new coal-fired power plants and requires installation of mercury technology on the Boardman plant and requires the plant to reduce its mercury emission by 90% by July 1, 2012.

PGE has a 20% ownership interest in Colstrip Units 3 and 4, which are operated by PPL Montana, LLC (PPL Montana). PPL Montana and the EPA are discussing possible emission control and monitoring requirements involving all Colstrip units to address certain issues that have arisen since late 2003, including those related to the CAA. Current emissions allowances are sufficient to operate Colstrip, which utilizes wet scrubbers.

In October 2006, the Montana Board of Environmental Review adopted final rules on mercury emissions from coal-fired generating units, including Colstrip, which set strict mercury emission limits by 2010 and established a review process to ensure that such facilities continue to utilize the latest mercury emission control technology.

It is expected that the CAA and related state air quality standards will require installation of additional emission controls at the Company's thermal generating plants. For further information, see "Environmental Matters" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

Item 1A. Risk Factors

The following risk factors, in addition to other factors and matters discussed in this report, have been identified as those that could have a significant impact on PGE's financial and operating results and should be considered when evaluating the Company.

PGE is subject to the risk that the OPUC will not allow sufficient recovery of the Company's costs and thus not provide a reasonable rate of return to shareholders.

The rates that the OPUC allows PGE to charge for its retail services is the 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. Further, the regulatory process does not provide assurance that PGE will be able to achieve earnings levels authorized.

The OPUC order in the Company's recent general rate case approved the use of a power cost adjustment mechanism by which PGE can adjust future rates to reflect differences between each year's forecasted and actual net variable power costs. However, use of the approved cost sharing ("deadband") methodology will require that PGE absorb some power cost increases before the Company is allowed to recover any amount from customers. Accordingly, future application of the power cost adjustment mechanism is expected to only partially mitigate the potentially adverse financial impact of unplanned generating plant outages, severe weather, reduced hydro availability, and volatile wholesale energy prices.

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

Unplanned outages at the Company's generating plants, such as the 2005-2006 outage at the Boardman coal plant, could result in replacement power costs greater than those power costs included in customer prices, and inability to recover such costs in future rates could again have a negative financial impact on the Company. As indicated above, application of a newly-approved power cost adjustment mechanism can be expected to partially offset adverse financial impacts of future unplanned outages at the Company's generating plants.

Weather conditions that reduce stream flows can adversely affect operating results.

PGE derives a portion of its power supply from its hydroelectric facilities and from those 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 will require increased generation from the Company's higher cost thermal plants and/or power purchases in the wholesale market, the adverse financial effects of which are not expected to be fully mitigated by the Company's new power cost adjustment mechanism.

Wholesale energy markets are subject to forces that are often not predictable and which can result in price volatility, deterioration of liquidity, and general market disruption, adversely affecting PGE's costs and ability to manage its energy portfolio and procure required energy supply.

Wholesale electricity prices in the western United States are influenced primarily by factors related to supply and demand. These factors 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 wholesale energy markets can affect the availability and prices of purchased power and demand for energy sales. Changes in the creditworthiness of large wholesale customers can also affect PGE's variable power costs. Further, disruption in wholesale markets may result in a deterioration of market liquidity, increase the risk of counterparty default, affect the regulatory and legislative process in unpredictable ways, affect wholesale energy prices, and impair PGE's ability to manage its energy portfolio. Changes in wholesale energy prices also affect the market value of derivative instruments and unrealized gains and losses, as well as cash requirements to purchase electricity. Although the Company's power cost adjustment mechanism can be expected to partially mitigate the financial effects of adverse wholesale market conditions, cost sharing features of the mechanism will prevent full recovery in customer rates.

Market risk related to adverse fluctuations in the price of natural gas purchased as fuel for electricity generation can also impact the Company. PGE purchases natural gas in the open market or pursuant to short-term or variable-priced contracts as part of its normal operating business. If market prices rise, especially during periods when the Company requires greater than expected volumes that must be purchased at market or short-term prices, PGE may incur greater costs than projected. The Company may not be able to timely recover these increased costs through ratemaking.

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

Weather conditions can adversely affect PGE's revenues and costs and have an impact on 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 power sales and revenues. Particularly for residential customers, weather conditions are the dominant cause of usage variations from normal seasonal patterns. Severe weather can also disrupt energy delivery and damage the Company's 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.

PGE is subject to the adverse effects of storms, natural disasters, and similar operational risks that are common to the utility industry.

The Company has exposure to natural disasters that can cause significant physical damage to its transmission and distribution facilities. Such events can interrupt the delivery of electricity, increase repair and service restoration expenses, and reduce revenues. Such failures, if repeated or prolonged, can also affect customer satisfaction and the level of regulatory oversight. Although regulated utilities are required to provide service to all customers within their service territory and have generally been afforded liability protection against customer claims related to service failures, constraints on insurance recovery related to the above events can also negatively impact financial results.

PGE is exposed to risk related to performance of contractual obligations by its wholesale suppliers and customers.

As the Company relies on suppliers to deliver natural gas, coal and electricity, in accordance with short- and long-term contracts, failure to timely comply with existing contracts 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 contractual agreements expire, PGE may be unable to continue to purchase natural gas, coal or electricity on terms equivalent to those of current agreements.

PGE is subject to political processes that may adversely affect its business.

Certain customer groups and governments could attempt to acquire PGE facilities and equipment in the Company's allocated service territory through the use of public ownership initiatives, utilizing initiative petition and condemnation processes. In 2003 and 2004, such initiatives were advanced in four counties in which most of PGE's customers reside. Although they were rejected by the voters, there is no certainty that similar efforts will not again be attempted. In addition, the City of Portland has indicated that it may pursue ratemaking for PGE's retail customers who reside within the City of Portland boundaries.

Oregon law related to income taxes could result in refunds to PGE's customers and adversely impact the Company's earnings.

A law, passed by the Oregon legislature in 2005, adjusts the way that PGE and other Oregon investor-owned electric and gas utilities recover income tax expense from customers through revenues for utility services. SB 408 attempts to more closely match income tax amounts collected in revenues with the amount of income taxes paid to governmental entities by investor-owned utilities or their consolidated group.

In September 2006, the OPUC issued a final order that adopted permanent rules to implement SB 408. Based on its assessment of the order, PGE has revised its estimate of potential refunds to customers to be approximately $42 million (including $2 million of accrued interest) for fiscal year 2006 and has recorded a (pre-tax) reserve of such amount for the year.

PGE will continue to evaluate its options for changing or modifying the legislation and rules, and challenging any adjustment that follows for the 2006 tax year. As the ultimate outcome of these matters is uncertain, the above estimates are subject to change. For further information, see "Utility Rate Treatment of Income Taxes" in "Financial and Operating Outlook" of Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operation."

Regulations involving compliance with both new and existing 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, Willamette, and Sandy rivers. Operations of these projects are 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 species 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.

Regulations involving compliance with state and federal laws related to emissions from thermal electric generating plants could adversely affect PGE's results of operations.

Oregon and federal regulators are currently reviewing air emissions from PGE's thermal generating plants in Oregon as part of separate regulatory processes related to haze, mercury, and the Company's air permits. Oregon regulators have adopted measures that will require installation of mercury controls at the Boardman coal plant. Additional emissions controls may be required at PGE's Boardman coal plant, although specific measures will depend on the outcome of the reviews. Installation of such control measures will increase expenditures for PGE and its customers. In addition, Montana regulators have adopted stricter requirements related to mercury emissions that could impact the operations of Colstrip, in which PGE has a 20% ownership interest. 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.

PGE is exposed to risks that impact the Company's ability to acquire those facilities required to meet the electricity demands of its customers.

Increases in both the number of customers and the demand for energy will require continued expansion and reinforcement of PGE's generation, transmission, and distribution systems. Construction of new generating facilities may 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, if construction projects are not completed according to specifications, reduced plant efficiency and higher operating costs could result. Equipment failure, the ability of generating plants to operate as intended, and other factors can result in plant performance that falls below expected levels. Cost and availability of fuel supplies, primarily natural gas and coal, can also impact the cost and output of the Company's thermal generating plants.

PGE faces regulatory and litigation risk with respect to recovery of the Company's investment in the closed Trojan Nuclear Plant.

There remains uncertainty regarding the ultimate outcome of legal and regulatory proceedings related to PGE's recovery of its investment in the Trojan Nuclear Plant, which was closed in 1993. In 1995, the OPUC granted PGE recovery of, and a rate of return on, the majority of the Company's investment in Trojan. Numerous challenges, appeals and reviews were subsequently filed in the courts on the issue of the OPUC's authority under Oregon law to grant recovery of, and a return on, the Trojan investment. The Oregon Court of Appeals has determined that the OPUC does not have the authority to allow PGE to recover a return on its Trojan investment and has remanded the case to the OPUC.

Pursuant to settlement agreements reached in September 2000 and approved by the OPUC, PGE's investment in Trojan was removed from the Company's balance sheet and is no longer included in rates charged to customers. The settlement agreements were subsequently challenged in both the courts and at the OPUC, with the case later remanded to the OPUC for action to reduce rates or order refunds.

Class action lawsuits were filed in 2003 seeking damages, on behalf of current and former PGE customers, resulting from the inclusion in customer rates of a return on Trojan during the period

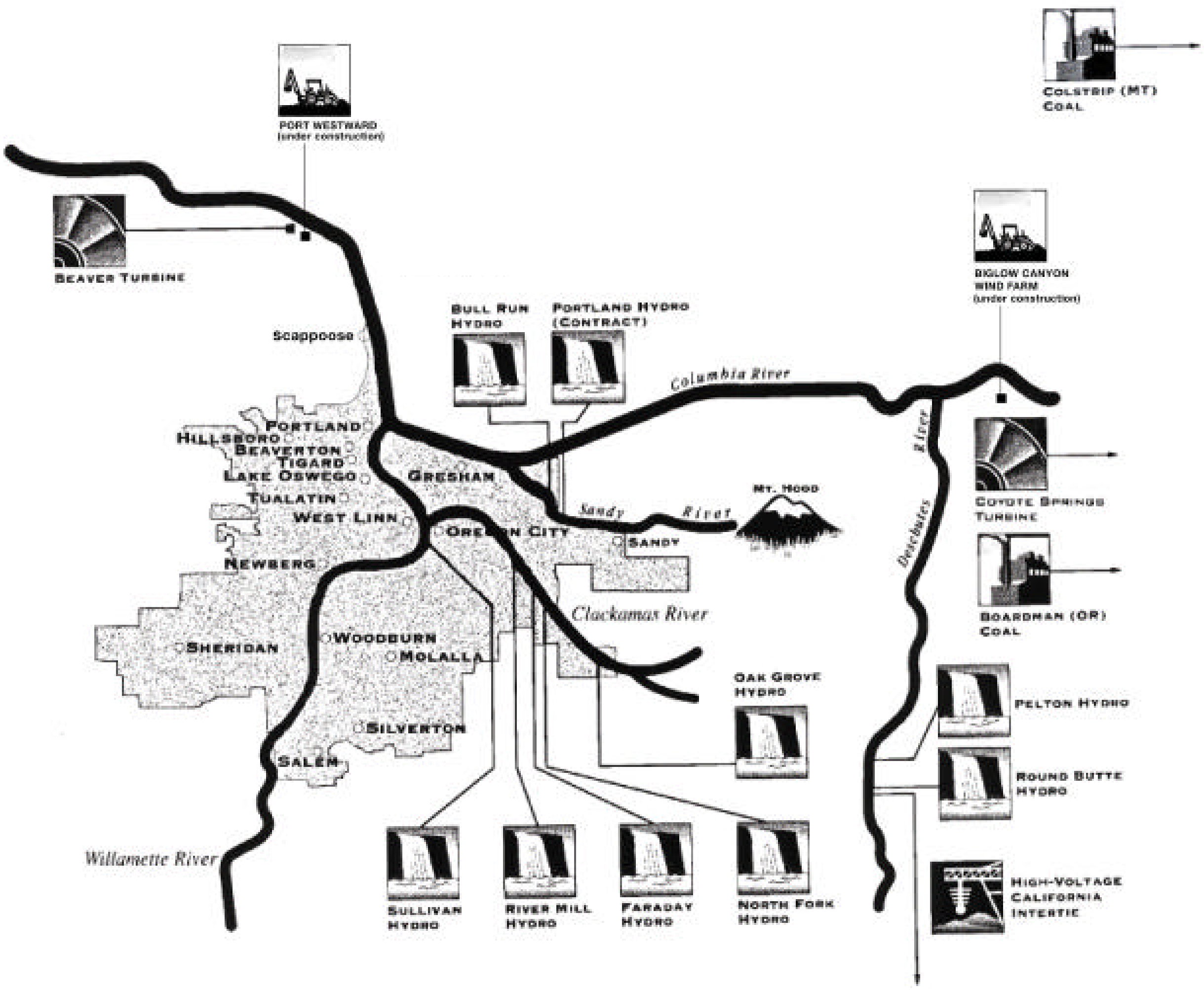
April 1995 through September 2000. In response to a ruling of the Oregon Supreme Court that the OPUC has primary jurisdiction to determine any remedies, through rate reductions or refunds, for these customers, the Marion County Circuit Court abated the class action proceedings in October 2006 for one year. For further information, see "Trojan Investment Recovery" in "Financial and Operating Outlook" of Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operation."

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

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



The following are generating facilities owned by PGE:

Facility	Location	Fuel	Net MW Capability At Dec. 31, 2006 (*)
Wholly Owned:			
Faraday	Clackamas River	Hydro	46
North Fork	Clackamas River	Hydro	58
Oak Grove	Clackamas River	Hydro	44
River Mill	Clackamas River	Hydro	25
Bull Run (a)	Sandy River	Hydro	22
Sullivan (b)	Willamette River	Hydro	17
Beaver	Clatskanie, OR	Gas/Oil	545
Coyote Springs	Boardman, OR	Gas/Oil	243
Jointly Owned:			
Boardman (c)	Boardman, OR	Coal	380
Colstrip 3 and 4 (d)	Colstrip, MT	Coal	296
Pelton (e)	Deschutes River	Hydro	73
Round Butte (e)	Deschutes River	Hydro	225
Total			1,974

(*) PGE ownership share.

(a) Decommissioning planned for 2007-2008.
(b) Increased 1 MW in 2006 due to turbine upgrades.
(c) PGE operates Boardman and has a 65% ownership interest.
(d) PPL Montana, LLC operates Colstrip 3 and 4; PGE has a 20% ownership interest.
(e) PGE operates Pelton and Round Butte and has a 66.67% ownership interest.

Hydro Relicensing

PGE holds FERC licenses under the Federal Power Act for its hydroelectric generating plants.

The license for the Clackamas River projects expired in 2006. PGE filed an application with the FERC in 2004 to relicense the projects. A March 2, 2006 settlement agreement with the participating parties was also submitted to the FERC for review and approval. Until a new license is issued, PGE will operate under annual licenses from the FERC. For further information, see "Hydro Relicensing" in Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operation."

In October 2002, PGE entered into an agreement with state and federal agencies, conservation groups, and others regarding removal of the Company's 22 MW Bull Run hydroelectric project located in the Sandy River basin, including removal of the Marmot Dam in 2007 and the Little Sandy Dam in 2008. The FERC issued a surrender order in 2004 and an annual operating license in early 2005 that allows PGE to operate the project until the removal of Little Sandy Dam. PGE has fully recovered its remaining plant investment and is recovering about $17 million in estimated decommissioning costs over a ten-year period that began in October 2001.

Port Westward

Construction of the Port Westward Generating Plant, a 400 MW natural gas-fired facility located in Clatskanie, Oregon is proceeding, with the plant expected to go into service in late April 2007.

Biglow Canyon Wind Farm

In November 2006, PGE executed an agreement to acquire 76 wind turbines for phase one construction of the Biglow Canyon Wind Farm, located in Sherman County, Oregon. The first phase of the project will have a total capacity of 125 MW (48 MWa), with completion expected by December 2007.

Transmission

PGE owns and has contractual access to transmission lines that deliver electricity from its Oregon plants to its distribution system in its service territory and also to the Northwest grid. The Company also has ownership in, and contractual access to, transmission lines that deliver electricity from the Colstrip plant in Montana to PGE. In addition, PGE owns approximately 16% of the Pacific Northwest Intertie, a 4,800 MW transmission facility between John Day, in northern Oregon, and Malin, in southern Oregon near the California border. This line is used primarily for 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, Marion County Oregon Circuit Court, the Court of Appeals of the State of Oregon, the Oregon Supreme Court.

Following the closing 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, citing an opinion issued by the Oregon Department of Justice that current law gave the OPUC authority to allow recovery of, and a return on, its Trojan investment and future decommissioning costs. The Declaratory Ruling was appealed to the Marion County Circuit Court, which upheld the OPUC's Declaratory Ruling in November 1994. 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 Utility Reform Project (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 does 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.

In August 1998, PGE 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. The URP filed a Petition for Review with the Oregon Supreme Court seeking review of that portion of the 1998 Decision relating to PGE's recovery of its undepreciated investment in Trojan.

In September 2000, PGE, CUB, and the OPUC Staff settled proceedings related to PGE's recovery of its investment in the Trojan plant (Settlement). The URP did not participate in the Settlement and filed a complaint and requested a hearing 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 URP's challenges and approving PGE's application for the accounting and ratemaking elements of the Settlement. URP appealed the Settlement Order to the Marion County Circuit Court.

On November 19, 2002, the Oregon Supreme Court dismissed PGE's and URP's Petitions for Review of the 1998 Decision. As a result, the 1998 Decision stands and the remand of the 1995 Order to the OPUC (1998 Remand) became effective.

In regards to the URP's appeal of the March 2002 Settlement Order, on November 7, 2003, the Marion County Circuit Court issued an opinion remanding the case to the OPUC for action to reduce rates or order refunds (2003 Remand). The opinion does not specify the amount or timeframe of any reductions or refunds. On February 9, 2004, PGE appealed the 2003 Remand to the Oregon Court of Appeals. The OPUC has also appealed.

On March 3, 2004, the OPUC re-opened Dockets DR 10, UE 88, and UM 989 and issued a notice of a consolidated procedural conference before an administrative law judge. On October 18, 2004, the OPUC affirmed the order (Scoping Order) issued by the administrative law judge defining the scope of the proceedings necessary to comply with the orders remanding this matter to the OPUC. The URP and Class Action Plaintiffs (see “Dreyer” below) filed an application with the OPUC for reconsideration of the Scoping Order, which the OPUC denied. On April 18, 2005, URP and Linda K. Williams filed a complaint in Marion County Circuit Court challenging the OPUC's affirmation of the Scoping Order. On September 21, 2005, the Marion County Circuit Court granted the OPUC's motion to dismiss the complaint.

The OPUC combined the 1998 Remand and the 2003 Remand into one proceeding and is considering the matter in phases. The first phase addresses what rates would have been if the OPUC had interpreted the law to prohibit a return on the Trojan investment. The subsequent phases will address reconciling the results of the first phase with actual rates, and adjusting rates to the extent necessary. A decision is pending in the first phase of the proceeding. On November 15, 2006, PGE filed a motion with the OPUC to Consolidate Phases and Re-Open the Record. A ruling on the motion is pending.

On February 16, 2007, the Oregon Court of Appeals declined to reverse or abate the 2003 Remand and ordered the parties to file revised briefs with the Court of Appeals.

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, 2001 (Current Class) and the Morgan case seeks to represent PGE customers that were customers during the period from April 1, 1995 to October 1, 2001, but who are no longer customers (Former Class, together with the Current Class, the Class Action Plaintiffs). The suits seek damages of $190 million for the Current Class and $70 million 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 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. PGE filed for an interlocutory appeal, which was rejected on February 1, 2005. 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 responds to the 2003 Remand.

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.

People of the State of Montana, *ex rel.* Mike McGrath, Attorney General of the State of Montana; Flathead Electric Cooperative, Inc., and Does 1 through 100, inclusive v. Williams Energy Marketing and Trading Company; Reliant Energy Services, Inc; Duke Energy Trading and Marketing, LLC; Mirant Corporation; Enron Energy Services, Inc.; Enron Power Marketing, Inc., Morgan Stanley Capital Group, Inc.; Powerex; El Paso Merchant Energy; American Electric Power; Avista Corporation; Portland General Electric Company; BP Energy; Goldman Sachs Group, Inc. and Does 1 through 100, Inclusive, Montana First Judicial District, Lewis and Clark County.

On June 30, 2003, the Montana Attorney General filed a complaint in Montana state court against PGE and numerous named and unnamed generators, suppliers, traders, and marketers of electricity and natural gas in Montana. The complaint alleges unfair and deceptive trade practices in violation of the Montana Unfair Trade and Practices and Consumer Protection Act, deception, fraud and intentional infliction of harm arising from various actions alleged to have been undertaken in the western wholesale electricity and natural gas markets during 2000 and 2001. The relief sought includes injunctive relief to prohibit the unlawful practices alleged, treble damages, general damages, interest, and attorney fees. No monetary amount is specified. The case was removed to the U.S. District Court of Montana in July 2003 then remanded back to Montana state court in November 2003. The case is pending in state court while investigation is underway by the Montana Public Service Commission (MPSC) in Docket No. D2004.2.21. PGE is not included in the MPSC proceeding and has not yet been served in the state court case.

Wah Chang, a division of TDY Industries, Inc. v. Avista Corporation, Avista Energy, Inc., Avista Power, LLC, Dynegy Power Marketing, Inc., El Paso Electric Company, IDACORP, Inc., Idaho Power Company, IDACORP Energy L.P., Portland General Electric Company, Powerex Corporation, Puget Energy, Inc., Puget Sound Energy, Inc., Sempra Energy, Sempra Energy Resources, Sempra Energy Trading Corp., Williams Power Company, Inc., United States District Court for the District of Oregon, Case No. 04-CV-00619-AS.

On May 5, 2004, Wah Chang, a division of TDY Industries, (Wah Chang) filed a complaint in the U.S. District Court for the District of Oregon against PGE and fifteen other companies (Wah Chang Defendants) alleging that practices among the Wah Chang Defendants and/or Enron and others involving the generation, purchase, sale and transmission of electric energy, beginning in 1998 and continuing through 2001, were designed to communicate false or misleading information to participants in the energy market with the purpose of causing a shortage or appearance of a shortage in the generation of electricity, the appearance of congestion in the transmission of electricity, illegally raising the price of electricity, and fraudulently concealing illegal activities, all in violation of Federal and state antitrust statutes, the Racketeer Influenced and Corrupt Organization Act and for wrongful interference with their purchase contracts with PacifiCorp. No specific facts as to PGE's activities are alleged. Wah Chang seeks compensatory ($30 million) and treble damages.

On February 11, 2005, the Court entered an order dismissing the case based on federal preemption of state law claims, the exclusive jurisdiction of the FERC over electricity markets, and the "filed rate doctrine" that holds that rates approved by a governing regulatory agency are reasonable and unassailable in judicial proceedings brought by ratepayers. On March 10, 2005, Wah Chang filed a notice of appeal in the Ninth Circuit Court of Appeals.

City of Tacoma, Department of Public Utilities, Dreyer, Light division v. American Electric Power Service Corporation, Quila Holdings, LLC, Aquila Power Corporation, Arizona Public Service Company, Automated Power Exchange, Inc., Avista Corporation, et. al., United States District Court for the Western District of Washington, Case No. C07-5325 RBL.

On June 7, 2004, the City of Tacoma, Washington filed a complaint in the U.S. District Court for the Western District of Washington against PGE and fifty-five other companies (Defendants) alleging that sometime during or before May 2000 and continuing through at least the end of 2001, the Defendants, acting in concert with some or all of thirty non-party co-conspirators, engaged in a pattern of activities involving the generation, purchase, sale and transmission of electric energy that violated the Sherman Antitrust Act and damaged the City of Tacoma in an amount estimated to exceed $175 million. No specific facts as to PGE's activities are alleged. The City of Tacoma seeks recovery of three times the amount of actual damages proved at trial. PGE contends this lawsuit is precluded by the 2003 settlement of FERC Docket No. EL02-114, under which PGE paid Tacoma $1.1 million and for which PGE obtained a complete release from all claims related to electricity prices during 2000-2001 from the California Parties, the City of Tacoma, and others.

On February 11, 2005, the Court entered an order dismissing the case based on federal preemption of state law claims, the exclusive jurisdiction of the FERC over electricity markets, and the "filed rate doctrine" that holds that rates approved by a governing regulatory agency are reasonable and unassailable in judicial proceedings brought by ratepayers.

On March 10, 2005, a notice of appeal was filed in the Ninth Circuit Court of Appeals.

Ankeny, et al v. Northwestern Energy, L.L.C.; PPL Montana, LLC; Puget Sound Energy, Inc.; Avista Energy, Inc.; Pacific Energy GP, Inc.; Pacific Energy Group LLC.; Touch America Holdings, Inc.; PacifiCorp; Bechtel Construction Operations Incorporated; Western Energy Company; Portland General Electric Company; and John Does 1-20, Montana Second Judicial District, Rosebud County, Case No. DV 03-109.

On May 5, 2003, residents of Colstrip, Montana, unions and businesses filed a suit against PGE and the other owners, designers and operators of the Colstrip coal-fired electric generation plants (Colstrip Project) in Montana alleging that holding and settling ponds at the Colstrip Project have leaked and contaminated groundwater. The plaintiffs allege nuisance, trespass, unjust enrichment, fraud, and negligence, and seek a declaratory judgment of nuisance and trespass, an order that the nuisance be abated, and an unspecified amount for damages, disgorgement of profits, and punitive damages.

On July 18, 2005, an Amended complaint was filed, which modifies the named plaintiffs and provides further clarification of the underlying claims.

<u>Portland General Electric Co. v. City of Glendale (California),</u> United States District Court for the District of Oregon, Case No. 051321.

On August 25, 2005, the Company filed a complaint in the U.S. District Court for the District of Oregon against the City of Glendale (Glendale) seeking a declaratory ruling with respect to a long-term power sale and exchange agreement between the Company and Glendale entered into in 1988 which expires in 2012. Under the agreement, Glendale purchases firm system capacity up to 20 MW plus associated energy costs as scheduled by Glendale. Glendale has requested refunds, asserting that its price is capped so the Company cannot charge a price greater than the most expensive generation resource in the Company's inventory. Glendale has also asserted that the shutdown of Trojan was the equivalent of a sale of a Company resource that triggered a duty under the agreement to renegotiate price terms "to avoid a significant distortion in the Parties' bargain." The Company's complaint seeks a declaratory ruling that the Company does not owe Glendale any amounts under the agreement and that the decommissioning of Trojan does not require the Company to renegotiate payments due to it from Glendale. On October 18, 2005, Glendale filed a complaint with the FERC requesting the FERC to direct the Company to adjust the price and provide refunds of approximately $23.3 million plus interest. The Court granted a stipulation filed by PGE and Glendale to stay the Court proceedings pending a decision by the FERC on its jurisdiction. On December 19, 2005, the FERC dismissed Glendale's complaint. Glendale then filed a request for a rehearing with the FERC, which was denied. A Notice of Appeal to the Ninth Circuit Court of Appeals was filed by Glendale on June 13, 2006. On December 6, 2006, the Ninth Circuit issued an order dismissing Glendale's petition for review of the FERC's December 19, 2005 Order dismissing Glendale's complaint. On January 31, 2007, Glendale filed a motion with the District Court to dismiss on the basis that the FERC has exclusive jurisdiction.

<u>City of Portland v. Oregon Public Utility Commission, Portland General Electric Company, Stephen Forbes Cooper, LLC, Citizens' Utility Board of Oregon, Industrial Customers of Northwest Utilities, Community Action Directors of Oregon, and Oregon Energy Coordinators Association,</u> Court of Appeals of the State of Oregon Case No. A131268GE and Marion County Oregon Circuit Court, Case No. 06C11248.

On February 10, 2006, the City of Portland appealed the December 14, 2005 order of the OPUC that authorized the issuance of new PGE common stock. Appeals were filed both in the Marion County Circuit Court and the Oregon Court of Appeals. On February 23, 2006, the OPUC filed a Motion to Hold Case in Abeyance with the Marion County Circuit Court in order to seek summary determination from the Court of Appeals regarding the proper court to hear the City of Portland's appeal. On April 6, 2006, the City of Portland filed to dismiss the action before the Oregon Court of Appeals, which the Court granted on July 19, 2006. On October 20, 2006, the City of Portland filed a Notice and Order of Voluntary Dismissal with the Marion County Circuit Court. On November 2, 2006, the Marion County Circuit Court dismissed the case.

<u>Portland General Electric Company vs. City of Portland,</u> Multnomah County Circuit Court for the State of Oregon, Declaratory Complaint Case No. 0604-04242, Writ Case No. 0604-04243.

On March 23, 2006, the City of Portland issued a subpoena to PGE seeking records relating to financial reporting, income tax filings, Multnomah County Business Income Tax, wholesale power, FERC investigations, and others matters.

On April 21, 2006, PGE filed a Petition for Writ of Review and a Complaint for Declaratory Judgment with the Multnomah County Circuit Court. The Writ of Review action challenges the authority of the City of Portland to issue a subpoena for the production of voluminous documents related to PGE's business activities, and seeks an order quashing the same. The City of Portland has agreed not to seek enforcement of the subpoena while this case is pending.

The Complaint for Declaratory Relief was filed against both the City of Portland and the State of Oregon, seeking a declaration that any power of the City of Portland to regulate or investigate regulated utility rates has been preempted, superseded, and/or impliedly repealed. The City of Portland filed motions against both complaints on June 9, 2006. The Court granted the City of Portland's Motion to Dismiss the Writ of Review case. PGE has appealed that decision. Further argument on the Declaratory Relief claim was held in December 2006, with a trial date set for April 2007.

<u>City of Portland v. Portland General Electric Company</u>, Complaint before the Public Utility Commission of Oregon; Docket No. UM1262.

On May 5, 2006, the City of Portland filed a complaint against PGE with the OPUC alleging that Enron and PGE should not have filed income taxes on a unitary basis under Oregon law. The complaint also alleged that PGE made certain cash payments to Enron under a tax allocation agreement which at the time had not been approved by the SEC, nor had PGE submitted the agreement to the OPUC, as provided under Oregon law.

On July 31, 2006, the OPUC issued an order dismissing two claims (that Enron and PGE should not have filed income taxes on a unitary basis under Oregon law and that PGE made certain cash payments to Enron under a tax allocation agreement which at the time had not been approved by the SEC) of the three claims made by the City of Portland. On November 17, 2006, the OPUC issued an order that granted summary judgment dismissing the remaining claim.

<u>Portland General Electric Company v. International Brotherhood of Electrical Workers, Local No. 125 (Union Grievances)</u>

In November 2001, grievances were filed by several members of the International Brotherhood of Electrical Workers (IBEW) Local 125, the bargaining unit representing PGE's union workers, with respect to losses in their pension/savings plan attributable to the collapse of the price of Enron's stock. The grievances, which allege that the losses were caused by Enron's manipulation of the stock, seek binding arbitration under Local 125's collective bargaining agreement on behalf of all present and retired bargaining unit members. The grievances do not specify an amount of claim, but rather request that the present and retired members be made whole. On May 24, 2002, PGE filed a Motion for Declaratory Relief in the Multnomah County Circuit Court for the State of Oregon, seeking a declaratory ruling that the grievances are not subject to arbitration under the collective bargaining agreement, that the grievances are preempted by the Employee Retirement Income Security Act of 1974 (ERISA), and that the conduct complained of is directed against Enron, not PGE.

On May 28, 2003, PGE filed a motion for summary judgment. On August 14, 2003, the Court granted PGE's motion for summary judgment finding that the grievances are not subject to arbitration. A final judgment was entered on October 6, 2003. On October 22, 2003, the IBEW filed an appeal to the Oregon Court of Appeals.

Both the U.S. District Court and the Bankruptcy Court approved the settlement of the class action litigation styled In re Enron Corp. Securities Derivative & "ERISA" Litigation, Pamela M. Tittle, et al, v. Enron Corp., et al, Civil Action No. H-01-3913, U.S. District Court for the Southern District of Texas, Houston Division (Tittle Action), and on September 13, 2005, the U.S. District Court entered a Bar Order in the Tittle Action, which specifically bars all claims arising out of that case, including the IBEW grievance proceeding. On July 5, 2006, the Oregon Court of Appeals held that the judgment in the Tittle Action precludes the IBEW from pursuing their grievances, therefore rendering the appeal moot. As a result, the appeal was dismissed. IBEW filed a Petition for Reconsideration on August 23, 2006, asking that the trial court opinion be vacated instead of dismissed. On November 1, 2006, the Court of Appeals granted the request and vacated the trial court opinion. On December 21, 2006, the IBEW filed a petition for review with the Oregon Supreme Court, which the Company has opposed.

Item 4. Submission of Matters to a Vote of Security Holders

None.

Executive Officers of the Registrant [1]

Name	Age	Business Experience
Peggy Y. Fowler Chief Executive Officer and President	55	Appointed to current position on April 1, 2000. Also served as Chair of the Board from May 2001 until January 2004. Served as President from February 1998 until appointed to current position. Served as President of Portland General Holdings, Inc.[2] (an Enron affiliate) from March 1999 until June 2003.
James J. Piro Executive Vice President, Finance, Chief Financial Officer and Treasurer	54	Appointed to current position on July 25, 2002. Served as Senior Vice President Finance, Chief Financial Officer and Treasurer from May 2001 until appointed to current position. Served as Chief Financial Officer and Senior Vice President of Portland General Holdings, Inc.[2] (an Enron affiliate) from July 2001 until June 2003.
Stephen R. Hawke Senior Vice President, Customer Service and Delivery	57	Appointed to current position on August 1, 2006. Served as Vice President, Customer Service and Delivery from August 2004 until appointed to current position. Served as Vice President, System Engineering, Utility Services and Customer Service from October 2003 until August 2004. Served as Vice President, System Engineering and Utility Services from July 1997 until October 2003.
Arleen N. Barnett Vice President, Administration, Corporate Compliance Officer	55	Appointed to current position on August 2, 2004. Served as Vice President, Human Resources and Information Technology and as Corporate Compliance Officer from May 2001 until appointed to current position. Served as Vice President, Human Resources from February 1998 until May 2001. Served as Vice President, Human Resources of Portland General Holdings, Inc.[2] (an Enron affiliate) from March 1998 until June 2003.
Carol A. Dillin Vice President, Public Policy	49	Appointed to current position on February 1, 2004. Served as Director of Public Affairs and Corporate Communications from April 1998 until appointed to current position.

Executive Officers of the Registrant [1]

Name	Age	Business Experience
Campbell A. Henderson Vice President, Information Technology and Chief Information Officer	53	Appointed to current position on August 1, 2006. Served as Chief Information Officer and General Manager, Information Technology from 2005 until appointed to current position. Served as Chief Information Officer for Stockamp and Associates, a health care consulting organization, from 2003 until 2004. Served as Vice President, Chief Information Officer of Willamette Industries from 1998 to 2002.
Ronald W. Johnson Vice President, Customers and Economic Development	56	Appointed to current position on August 2, 2004. Served as Vice President, Customer Resource Strategy and Generation Engineering from July 2002 until appointed to current position. Served as Vice President, Power Supply, Resource Development and Engineering Services from January 2001 until July 2002.
Pamela G. Lesh Vice President, Regulatory Affairs and Strategic Planning	50	Appointed to current position on August 2, 2004. Served as Vice President, Regulatory and Federal Affairs from June 2002 until appointed to current position. Served as Vice President, Public Policy and Regulatory Affairs from May 2001 until June 2002.
James F. Lobdell Vice President, Power Operations and Resource Planning	48	Appointed to current position on August 2, 2004. Served as Vice President, Power Operations from September 2002 until appointed to current position. Served as Vice President, Risk Management Reporting, Controls and Credit from May 2001 until September 2002. Served as Senior Director of Business Development from July 1999 to May 2001.
Joe A. McArthur Vice President, Customer Service	59	Appointed to current position on July 1, 2006. Served as Vice President, Distribution from July 1997 until appointed to current position.
Douglas R. Nichols Vice President, General Counsel and Secretary	64	Appointed to current position on May 1, 2001. Served as Acting Deputy General Counsel from February 2001 until appointed to current position. Served as Assistant General Counsel from May 1991 to February 2001. Served as General Counsel of Portland General Holdings, Inc.[2] (an Enron affiliate) from June 2001 until June 2003.

Executive Officers of the Registrant [1]

Name	Age	Business Experience
Stephen M. Quennoz Vice President, Nuclear and Power Supply/ Generation	59	Appointed to current position on August 2, 2004. Served as Vice President, Generation from January 2001 until appointed to current position. Served as Vice President Nuclear and Thermal Operations from October 1998 until January 2001.

(1) As of February 28, 2007. Officers of PGE are elected for one-year terms or until their successors are elected and qualified.

(2) Portland General Holdings, Inc. (PGH) filed for bankruptcy protection on June 27, 2003. PGH's bankruptcy case was dismissed by the Bankruptcy Court on October 20, 2005. PGH, a wholly-owned subsidiary of Enron, remained with Enron following the April 3, 2006 separation of PGE from Enron.

Part II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

In accordance with Enron's Chapter 11 Plan, on April 3, 2006 PGE issued 62.5 million shares (of 80 million, no par value, shares authorized) of new PGE common stock. Approximately 27 million shares of the new PGE common stock were initially issued to the Debtors' creditors holding allowed claims, and approximately 35.5 million shares were issued to a the DCR, where the shares will be held to be released over time to the Debtors' creditors holding allowed claims, in accordance with the Chapter 11 Plan. Distributions are generally scheduled for April and October of each year. Since the initial distribution, approximately 3.5 million shares of PGE common stock have been released from the DCR, with approximately 32 million shares held in the DCR as of February 1, 2007. The 42.8 million shares of PGE common stock previously held by Enron were cancelled.

The new PGE common stock is traded on the New York Stock Exchange under the ticker symbol POR. At January 31, 2007, there were 1,355 holders of record of PGE's common stock. Quarterly stock prices since the April 3, 2006 issuance of new PGE common stock are indicated in the table below.

	Price Range		Dividends Declared Per
2006 - Quarter	**High**	**Low**	**Share**
1	-	-	-
2	$ 31.11	$ 24.97	$0.225
3	26.60	24.25	0.225
4	28.65	24.12	0.225
2005 - Quarter			
1	-	-	-
2	-	-	-
3	-	-	$150 million (*)
4	-	-	-

(*) Paid to Enron in July 2005.

The OPUC order approving the issuance of new PGE common stock includes a stipulation containing several conditions, including a requirement that, after issuance of the new common stock, PGE cannot pay common stock dividends that would reduce the Company's common equity capital below 48% of total capitalization (excluding short-term borrowings) without prior OPUC approval. The requirement is reduced to 45% when the DCR holds between 20% and 40% of the issued and outstanding common stock of PGE, with no minimum common equity capital percentage requirement when the DCR holds less than 20% of the issued and outstanding common stock of PGE. At February 1, 2007, the DCR held approximately 51% of the total outstanding common stock of PGE. Other conditions include a requirement that the OPUC be notified (simultaneously with the public) of any dividend declared by PGE's Board of Directors.

PGE expects to pay regular quarterly dividends on its common stock. However, the declaration of such dividends is at the discretion of the Company's Board of Directors and is not guaranteed. The amount of common dividends will depend upon PGE's results of operations and financial condition, future capital expenditures and investments, any applicable regulatory and contractual restrictions, and other factors that the Board of Directors considers relevant.

Item 6. Selected Financial Data

	For the Years Ended December 31				
	2006	**2005**	**2004**	**2003**	**2002**
	(In Millions, except per share amounts)				
Operating Revenues (a)	$ 1,520	$ 1,446	$ 1,454	$ 1,752	$ 1,855
Net Operating Income	121	126	150	124	135
Net Income	71	64	92	60	66
Basic earnings per common share (b)	1.14	1.02	1.48	0.94	1.04
Diluted earnings per common share (b)	1.14	1.02	1.48	0.94	1.04
Dividends declared per common share	0.68	*	*	*	*
Total Assets (c)	3,767	3,638	3,403	3,372	3,455
Long-Term Debt (d)	1,003	890	922	983	1,046

(a) Operating Revenues for 2003 through 2006 reflect the October 1, 2003 adoption of EITF 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, and 'Not Held for Trading Purposes'." EITF 03-11 requires that realized gains and losses associated with non-trading derivative activities that are not physically settled be reported on a net basis. Prior to October 1, 2003, such settlements were recorded on a gross basis in both Operating Revenues and Purchased Power and Fuel expense. Amounts for periods prior to October 1, 2003 were not reclassified. Accordingly, Operating Revenues for these periods are not fully comparable to the years 2003 through 2006 and do not reflect PGE's current reporting. For further information, see Note 1, Summary of Significant Accounting Policies, in the Notes to Financial Statements.

(b) In accordance with Enron's Chapter 11 Plan, on April 3, 2006 PGE issued 62.5 million shares (of 80 million, no par value, shares authorized) of new PGE common stock. The 42.8 million shares of PGE common stock previously held by Enron were cancelled. PGE accounted for the stock issuance in the same manner as a stock split and has retroactively adjusted all periods presented. Accordingly, both basic and diluted earnings per common share for all years presented are based on the number of new shares.

(c) Amounts for 2002 were reclassified from those reported in the Form 10-K to reflect the transfer of accumulated asset retirement removal costs from Accumulated Depreciation to Other liabilities, in accordance with SFAS No. 143, Asset Retirement Obligations, and SFAS No. 71, Accounting for the Effects of Certain Types of Regulation.

(d) Includes long-term debt and preferred stock subject to mandatory redemption requirements.

* Not meaningful as the Company was a wholly-owned subsidiary of Enron.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation

Overview

General - Portland General Electric Company (PGE, or the Company) is a single 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 states and Canada. The Public Utility Commission of Oregon (OPUC) establishes tariffs and retail revenue requirements based upon the cost to serve retail customers and a fair return on investment, using a forecasted test year and an original cost rate base. Wholesale power and transmission prices are regulated by the Federal Energy Regulatory Commission (FERC). While Oregon law provides for both direct access to competing energy suppliers and market price options, the Company remains obligated to provide service to all of its retail customers, the large majority of which buy electricity at prices determined by the cost of service. Subject to regulatory review and timing, PGE expects the OPUC to recognize all prudently-incurred costs in setting prices, although there can be no assurance that the Company will have an opportunity to fully recover its costs through prices set in the regulatory process. While the OPUC order in PGE's recent general rate case allows the Company to adjust customer prices for changes in forecasted power costs on an annual basis, prices applicable to forecasted non-power costs are adjusted only in a general rate proceeding.

PGE's mission is to be a company that customers and communities depend upon to provide electric service in a safe, responsible and reliable manner, with excellent customer service, at a reasonable price. The Company's stated long-term goals are to achieve and maintain high customer value, provide reliable and reasonably priced power, achieve strong financial performance, attract and retain an engaged and valued workforce, and maintain its tradition of active corporate responsibility.

The continued strength of Oregon's economy has contributed to sustained customer growth and increasing demand for electricity within PGE's service territory. New thermal generation is expected to come on line in late April 2007 to help meet continued load growth and supplement the output of the Company's current generating facilities. In addition, PGE is pursuing its commitment to renewable energy as it plans for new wind generation resources and supports new legislative initiatives that encourage the growth of renewable energy in Oregon. The Company's integrated resource planning process includes consideration and acquisition of a diversified resource portfolio that balances cost, price stability, and overall risk.

In August 2006, the Oregon Supreme Court ruled on the case involving recovery of PGE's investment in Trojan. Although considerable uncertainty remains with respect to this matter, PGE views this as a step toward ultimate resolution. In September, the OPUC issued permanent rules for the implementation of Oregon Senate Bill 408 (SB 408), which adjusts the way that Oregon utilities recover income tax expense from customers; as a result, the Company has recorded a reserve for potential customer refunds. Further discussion of these matters is contained in the "Financial and Operating Outlook" section of this Item 7.

Demolition of major structures at the closed Trojan nuclear power facility is continuing, with implosion of the cooling tower successfully completed in May 2006. Remaining structures, including the plant's containment building, will be removed over the next two years, with demolition work designed to minimize impacts on the environment and surrounding communities.

Ownership of PGE - The transition of PGE to an independent publicly-owned company occurred in April 2006 with the issuance of new PGE common stock. Following the stock issuance and execution of a separation agreement, PGE is no longer a subsidiary of Enron.

Distribution of new PGE common stock from a Disputed Claims Reserve (DCR) to Enron creditors is continuing, with approximately one-half of the 62.5 million outstanding shares distributed as of February 1, 2007. The new common stock is listed on the New York Stock Exchange under the ticker symbol POR. The Company's Annual Meeting of Shareholders, its first as a newly-independent company, will be held on May 2, 2007. For further information, see "Ownership of PGE" in "Financial and Operating Outlook" of this Item 7.

Customers - PGE continues its focus on customer service and recognizes the importance of reliability, restoration response, safety, and reasonable rates in maintaining overall customer satisfaction. The Company continues to effectively maintain and improve its transmission, distribution, and customer service systems to meet regulatory standards for safety and service quality related to outage frequency and duration.

Like most utilities, PGE's business is affected by the general economy and by population growth in its service territory. The Company continues to experience customer growth, adding approximately 57,000 retail customers in the last five years (including 13,000 in 2006), and now serves 793,000 customers as the largest retail supplier of electricity in the state.

Oregon's economy continued to expand in 2006, adding over 135,000 jobs (including 15,000 in manufacturing) during the last three years, continuing its rebound from the 2001-2003 period. Such growth resulted in annual average payroll gains of 2% in 2004, 3.4% in 2005, and 3.1% in 2006. The state's payroll growth in 2006 ranked among the highest of all 50 states and considerably exceeded the 1.4% U.S. growth rate. Oregon's 5.4% average unemployment rate in 2006 was down from 6.2% in 2005 and markedly improved from the high of 8.5% in July 2003. Oregon's non-farm employment (seasonally adjusted) in December 2006 exceeded the previous peak set in November 2000. Continued high energy prices could, however, affect the future growth of both the state and national economy.

PGE's total retail energy deliveries in 2006 increased 3.6% over 2005 as the result of continued customer growth, higher industrial sales, and weather conditions. On a weather adjusted basis, retail energy deliveries increased 2.7% from 2005, with higher energy use by all major customer sectors. On July 24, 2006, the Company recorded a new all-time high net system load "summer peak" of 3,706 MW, also the highest for the year.

PGE offers customers numerous service options under Oregon's 2002 electricity restructuring law. In 2006, non-residential customers with a total average load of approximately 125 MWa (5% of PGE's total retail load) purchased their energy requirements from Electricity Service Suppliers (ESSs). It is currently estimated that customers with a total average load of approximately 270 MWa (11% of PGE's total retail load) will purchase from ESSs in 2007. While these "direct access" customers purchase their electricity from other suppliers, PGE continues to deliver energy to these customers and is not adversely impacted financially. Other options include market-based pricing and renewable resource rates. About 50,000 customers have enrolled in renewable energy programs, with PGE recently recognized by the U.S. Environmental Protection Agency (EPA) and the U.S. Department of Energy (USDOE) as the nation's leader in "green power" consumption by residential customers.

PGE's ongoing maintenance of its transmission and distribution systems, as well as its commitment to customer service and outage preparedness, enabled the Company to effectively restore service to customers that lost power during a severe windstorm in mid-December 2006. The storm was the worst that PGE has experienced in the last decade and affected nearly 250,000 customers throughout the Company's service territory.

PGE is investigating a system-wide advanced metering infrastructure (AMI) network which, if implemented, would serve nearly all of the Company’s residential and commercial customers. The AMI project, which is subject to review and approval by the OPUC, is expected to result in support for demand response and direct load control programs, provide new and improved services to customers, and achieve operational efficiencies and cost reductions. PGE will be moving the AMI project through the regulatory process and expects an OPUC decision in the third quarter of 2007. If approved, it is expected that the full project would be completed by the end of 2009 at a total cost of approximately $140 million.

Power Supply - PGE relies on its thermal and hydroelectric generating resources, as well as wholesale market purchases, to meet its customers' energy needs. PGE's thermal generation portfolio was restored to full strength in the second half of 2006 with the return of the Boardman coal plant to operations on July 1. Regional hydro conditions in 2006 approximated average levels and were significantly improved from the Pacific Northwest's severe to moderate drought conditions of the past three years. Increased stream flows in both the Clackamas and Deschutes river systems, where PGE's hydro facilities are located, resulted in a 28% increase in hydro generation from 2005. Improved regional conditions resulted in a 13% increase in output received from mid-Columbia River hydro projects with which PGE has long-term power purchase contracts, and have also contributed to lower wholesale market prices. Early forecasts indicate near normal hydro conditions in 2007.

PGE continues to implement its current Integrated Resource Plan (IRP) to meet the electricity needs of its growing customer base. The 400 MW Port Westward natural gas-fired plant is expected to go into service in late April 2007 and an agreement has been executed for the purchase of wind turbines for the first phase of the Biglow Canyon Wind Farm (125 MW), expected to be completed by the end of 2007. PGE currently plans to file a new IRP with the OPUC in the second quarter of 2007.

Regulatory bodies are examining the issues of regional haze and mercury in the atmosphere and could require that the Company make modifications to its thermal generating facilities. The EPA and several states, including Oregon and Montana, are expected to tighten controls on mercury emissions, which could have an impact on both the Boardman and Colstrip plants. Although the full impact of future state and federal remediation measures is not yet determinable, it is expected that such measures will increase expenditures for PGE and be included in customer rates.

Regulatory Matters - On January 12, 2007, the OPUC issued an order in PGE's general rate case approving an overall price increase of 1.3%. The increase represents the combined effect of a 1.4% decrease related to general costs, which became effective on January 17, 2007, and a 2.8% increase related to cost recovery of Port Westward, to become effective when the plant goes into service, expected to be in late April 2007. The decrease related to general costs primarily reflects reductions in forecasted test year costs and the effects of decisions regarding cost of capital. In addition, the OPUC approved a 5.1% price increase to cover higher power costs, as determined under PGE's Resource Valuation Mechanism (RVM), which became effective on January 1, 2007. The OPUC also approved a new Annual Power Cost Update Tariff, with rate adjustments to reflect updated power cost forecasts, and a Power Cost Adjustment Mechanism (PCAM), with rate adjustments reflecting the difference between forecast and actual power costs. The approved change in retail prices is based upon a 50% equity capital structure and a 10.1% return on equity. For further information, see "Resource Valuation Mechanism" and "General Rate Case" in "Financial and Operating Outlook" of this Item 7.

On February 12, 2007, the OPUC issued an order authorizing PGE to defer for future rate recovery $26.4 million of excess power costs related to Boardman's 2005-2006 outage. For further information, see "Boardman Coal Plant - Repair Outages" in "Financial and Operating Outlook" of this Item 7.

SB 408, which adjusts the way that PGE and other Oregon investor-owned utilities recover income tax expense from customers through revenues for utility services, became effective in 2006. Based on PGE's assessment of the OPUC's permanent rules, the Company has established a $42 million reserve (including $2 million of accrued interest) for potential refunds to customers. PGE believes that SB 408 has resulted in some unintended financial impacts and will continue to evaluate its options for changing or modifying the legislation and rules.

A settlement agreement related to the license application for the Company's four hydroelectric projects on the Clackamas River was submitted to the FERC in March 2006 for review and approval. PGE will continue to operate under annual licenses from the FERC until a new license is issued.

Financial Performance - Earnings for 2006 were somewhat higher than in 2005 due primarily to non-operating factors. In addition, reserves established for potential customer refunds under SB 408 and the high cost of power to replace the output of Boardman during the plant's outage in the first half of 2006 were only partially offset by the positive results of PGE's operations, resulting from higher energy sales and improved hydro conditions, during the year.

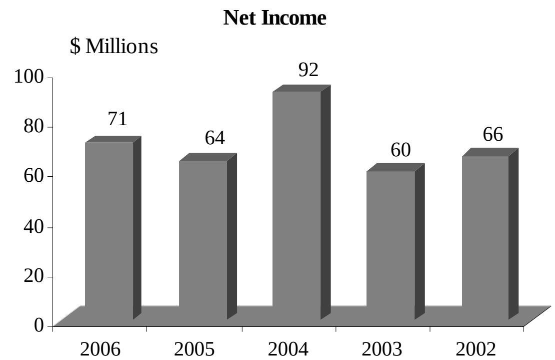
PGE maintains its investment grade bond ratings and stable operating cash flow, with adequate liquidity available through both its $400 million credit facility and access to the commercial paper market. The Company issued $275 million of First Mortgage Bonds in May 2006 and has reached an agreement to issue an additional $170 million of First Mortgage Bonds by June 1, 2007. Such sources, combined with the Company's long-term borrowing capability, provide for continued capital requirements, including investments in the new Port Westward and Biglow Canyon generating facilities.

Following the issuance of new PGE common stock, the Company declared and paid a total of $42 million in dividends in 2006 and early-2007 and currently expects to continue to pay regular quarterly dividends. PGE's objective is to maintain a common equity ratio of approximately 50% in order to maintain acceptable credit ratings and allow access to long-term capital at reasonable rates. PGE's common equity ratio at December 31, 2006 was 53.0%.

Results of Operations

2006 Compared to 2005

PGE's net income in 2006 was $71 million ($1.14 per diluted share) compared to $64 million ($1.02 per diluted share) in 2005. Results for 2005 included a $6 million after tax reserve related to the refund to customers of previously collected local income taxes. In 2006, PGE recorded a $26 million after tax reserve for a potential refund obligation to customers, reflecting the Company's current estimate of the impact of SB 408. The Company also incurred $46 million in

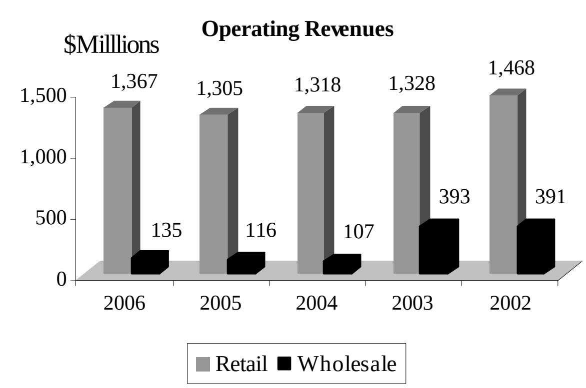


incremental replacement power costs in 2006 (compared to $40 million in 2005) related to the extended, unplanned outage at the Boardman coal plant, resulting in a $4 million after tax decrease in earnings. PGE also incurred higher distribution expenses in 2006, including those related to winter storm restoration. The SB 408 reserve, higher Boardman replacement power costs, and increased distribution expenses were partially offset by the combined effect of higher energy sales, resulting from both an increase in customers served and weather conditions, and increased hydro availability, resulting from improved stream flows.

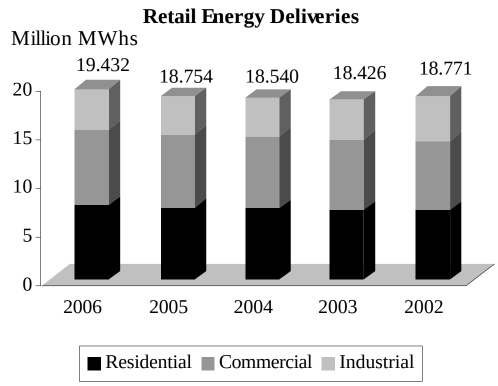
The following tables summarize Operating Revenues and Energy sold and delivered for 2006 and 2005:

	2006	2005	Increase/ (Decrease)
Operating revenues (millions)			
Retail sales			
Residential	$ 628	$ 593	$ 35
Commercial	547	505	42
Industrial	206	178	28
Total retail sales	1,381	1,276	105
Direct access customers			
Commercial	(6)	1	(7)
Industrial	(6)	-	(6)
Tariff revenues	1,369	1,277	92
Accrued revenues	38	28	10
Provision for refund - SB 408	(40)	-	(40)
Total retail revenues	1,367	1,305	62
Wholesale revenues (non-trading)	135	116	19
Other operating revenues	18	25	(7)
Total Operating Revenues	$ 1,520	$ 1,446	$ 74

	2006	2005	Increase/ (Decrease)
Energy sold and delivered - MWhs (000's)			
Retail energy sales			
Residential	7,573	7,323	250
Commercial	7,319	7,069	250
Industrial	3,541	3,148	393
Total retail energy sales	18,433	17,540	893
Delivery to direct access customers			
Commercial	430	400	30
Industrial	569	814	(245)
Total retail energy deliveries	19,432	18,754	678
Wholesale sales (non-trading)	3,312	2,094	1,218
Trading activities	-	815	(815)
Total energy sold and delivered	22,744	21,663	1,081
Customers - end of period			
Residential	696,779	685,568	11,211
Commercial	95,734	94,012	1,722
Industrial	259	257	2
Total retail customers	792,772	779,837	12,935



Total Operating Revenues increased about 5% from 2005 due to increases in both Retail and Wholesale Revenues. The increase in Retail Revenues resulted from both higher energy sales and a 2006 rate increase related to higher power costs. (See "Resource Valuation Mechanism" in "Financial and Operating Outlook" of this Item 7 for further information). Partially offsetting these increases was a $40 million pre-tax reserve for a potential refund obligation to customers related to the Company's current estimates of the impact of SB 408. (See "Utility Rate Treatment of Income Taxes" in the "Financial and Operating Outlook" of this Item 7 for further information). In addition, there was a $26 million reduction in the collection of regulatory assets (fully offset within Net Operating Income due to a corresponding decrease in Depreciation and Amortization expense). The reduction in Direct Access Customer Revenues resulted from "transition adjustment" credits reflecting the difference between the cost and market value of PGE's power supply portfolio, as provided by Oregon's electricity restructuring law.



A 3.6% increase in Total retail energy deliveries in 2006 resulted from approximate 13,500 increase in the average number of customers served during the year, higher commercial and industrial energy use, and weather conditions. Energy deliveries to all major customer classes increased, with residential energy sales up 3.4% and commercial and industrial deliveries both up 3.7%. A 12.5% increase in energy sales to industrial customers was primarily attributable to two large customers, one of which normally generates most of its own power requirements and another which purchased its energy from an ESS in 2005 but returned to PGE for service at the beginning of 2006. Colder weather in February, March, and October, along with significantly warmer weather in June and September, also contributed to higher energy use.

Wholesale revenues increased 16% in 2006 due to higher wholesale energy sales that resulted from favorable hydro generation conditions and excess wholesale power purchases. This quantity increase was partially offset by lower average spot market prices that resulted primarily from increased regional hydro generation.

The decrease in Other Operating Revenues from last year was primarily the result of current year losses from the sale of natural gas in excess of generating plant requirements.

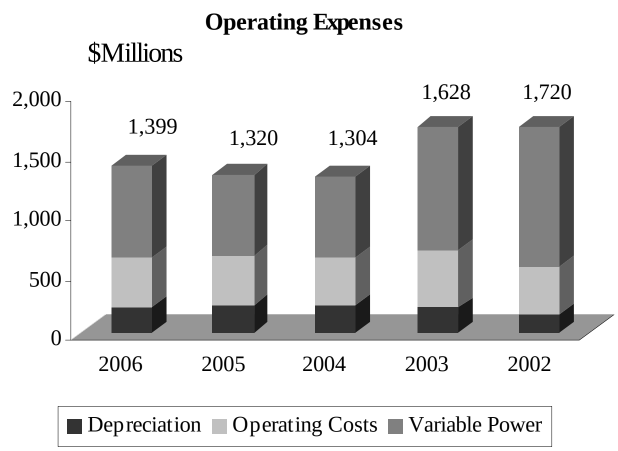
Purchased Power and Fuel expense for 2006 increased $92 million (14%) from 2005. The increase was due to higher power purchases required to meet a 10% increase in total system load requirements, an increase in the cost of replacing coal-fired generation at Boardman, and higher wholesale prices. Approximately $52 million and $40 million of incremental power costs were incurred in 2006 and 2005, respectively, to replace the output of Boardman, which was taken out of service in late October 2005 for repair of the plant's turbine rotor and which remained out of service for most of the first half of 2006 for additional repairs, including those to the plant's generator rotor. Partially offsetting incremental replacement power costs in 2006 was the deferral, for later ratemaking treatment, of $6 million related to the Boardman outage. (See "Boardman Coal Plant - Repair Outages" in "Financial and Operating Outlook" of this Item 7 for further information). The above cost increases were partially offset by the effect of improved regional hydro conditions.

Company generation decreased about 8% from 2005, with reduced thermal generation (related primarily to Boardman's outage) partially offset by a 28% increase in PGE hydro production, resulting from increased stream flows. Total generation met approximately 37% of PGE's retail load in 2006, compared to 42% in 2005. Production from PGE's hydro plants met approximately 10% of total retail load requirements, compared to 8% in 2005, while output received under long-term power purchase contracts from mid-Columbia River hydro projects met approximately 14% of total retail load, compared to 15% in 2005.

The following table indicates PGE's total system load (including both retail and wholesale) for the last two years. Average variable power costs include wheeling and exclude unrealized gains and losses from derivative instruments.

Megawatt-Hours/Variable Power Costs

	Megawatt-Hours (thousands)		Average Variable Power Cost (Mills/KWh)	
	2006	2005	2006	2005
Generation	7,209	7,821	13.8	13.7
Term Purchases	13,582	11,705	40.8	35.3
Spot Purchases	2,229	1,361	25.1	57.4
Total System Load	23,020	20,887	33.6	31.3



Production, distribution, administrative and other expenses increased $8 million (3%) from 2005. Higher expenses in 2006 resulted from maintenance and repair activities at PGE's thermal generating plants, storm-related service restoration costs, and increased tree trimming costs. A decrease in administrative and other expenses was largely the result of the settlement of certain asserted claims in 2005. Depreciation and Amortization expense decreased $14 million (6%), as a $26 million decrease in the amortization of regulatory assets (fully offset within Net Operating Income due to a corresponding decrease in Operating Revenues) was partially offset by increased depreciation of transmission and distribution plant.

Income taxes decreased $8 million due primarily to lower taxable income and a reduction in state income taxes resulting from apportionment rule changes.

Other Income (Miscellaneous) increased $6 million, related primarily to the establishment, in 2005, of a $10 million reserve for the refund to Multnomah County customers of previously collected income taxes. (See "Class Action Lawsuit - Multnomah County Business Income Taxes" in the "Financial and Operating Outlook" of this Item 7 for further information). Partially offsetting this increase was a $3 million decrease in interest income on regulatory assets, due to declining balances as amounts are recovered from customers. The $8 million increase in Allowance for equity funds used during construction was related primarily to Port Westward.

2005 Compared to 2004

PGE's net income in 2005 was $64 million compared to $92 million in 2004. The decrease was due primarily to reduced margins on energy sales, caused by replacement power costs for the extended, unplanned outage at the Boardman coal plant for repair of the plant's turbine rotor. In addition, results for 2005 were adversely affected by higher administrative and general expenses (including the settlement of certain asserted claims), a reserve for the refund to customers of previously collected local income taxes, and higher expenses related to preventive maintenance of the Company's distribution facilities.

The following tables summarize Operating Revenues and Energy sold and delivered for 2005 and 2004:

	2005	2004	Increase/ (Decrease)
Operating revenues (millions)			
Retail sales			
Residential	$ 593	$ 585	$ 8
Commercial	505	502	3
Industrial	178	176	2
Total retail sales	1,276	1,263	13
Direct access customers			
Commercial	1	2	(1)
Industrial	-	5	(5)
Tariff revenues	1,277	1,270	7
Accrued revenues	28	48	(20)
Total retail revenues	1,305	1,318	(13)
Wholesale revenues (non-trading)	116	107	9
Other operating revenues			
Trading activities – net	-	1	(1)
Other	25	28	(3)
Total Operating Revenues	$ 1,446	$ 1,454	$ (8)
Energy sold and delivered - MWhs (000's)			
Retail energy sales			
Residential	7,323	7,270	53
Commercial	7,069	7,247	(178)
Industrial	3,148	3,247	(99)
Total retail energy sales	17,540	17,764	(224)
Delivery to direct access customers			
Commercial	400	159	241
Industrial	814	617	197
Total retail energy deliveries	18,754	18,540	214
Wholesale sales (non-trading)	2,094	2,539	(445)
Trading activities	815	9,699	(8,884)
Total energy sold and delivered	21,663	30,778	(9,115)
Customers - end of period			
Residential	685,568	674,426	11,142
Commercial	94,012	92,389	1,623
Industrial	257	251	6
Total retail customers	779,837	767,066	13,771

Total Retail Revenues decreased about 1% from 2004. A decrease in energy sales and a $23 million reduction in amounts recovered from customers related to power cost adjustment mechanisms in effect in 2001 and 2002 (fully offset within Purchased Power and Fuel expense) were partially offset by a 1.4% average rate increase for 2005. (For further information, see "Resource Valuation Mechanism" in "Financial and Operating Outlook" of this Item 7). The decrease in Direct Access Customer Revenues, consisting of service charges for electricity delivered to customers who purchase energy requirements from ESSs, was attributable to "transition adjustment" credits, reflecting the difference between the cost and market value of PGE's power supply portfolio, as provided by Oregon's electricity restructuring law. Total Retail Energy Sales decreased 1%, with declines in both commercial and industrial usage partially offset by increased residential use resulting from colder weather in the fourth quarter of 2005 and an approximate 11,000 increase in customers served. Declines in commercial and industrial energy sales of 2.5% and 3.1%, respectively, were largely related to customers who chose to purchase their energy requirements from ESSs beginning in 2005. PGE continues to deliver energy to these customers, with about one-third of the increase in Total Retail Energy Deliveries in 2005 attributable to a single large industrial customer.

Wholesale revenues increased by about 8% in 2005 due primarily to a 32% increase in average price, driven largely by higher natural gas prices. This was partially offset by an approximate 18% reduction in wholesale electricity sales resulting from reduced market activity.

The decrease in Other Operating Revenues from last year was caused primarily by reduced margins on the sale of natural gas in excess of plant requirements.

Purchased Power and Fuel expense for 2005 increased $4 million (1%) from 2004. An 11% increase in PGE's average variable power cost was largely offset by both a reduction in total system load and a $24 million decrease related to the amortization of costs deferred under power cost adjustment mechanisms in effect during 2001 and 2002, which were later recovered from customers (fully offset within Retail revenues). The increase in average variable power cost was caused primarily by approximately $40 million of incremental power costs incurred to replace coal-fired generation at Boardman, which was taken out of service in mid-October 2005 for removal and repair of the plant's turbine rotor. Lower hydro production in 2005 (due to low stream flows) also contributed to the year's higher average variable power cost. Such cost increases were partially offset by higher unrealized gains from derivative instruments. Company generation decreased about 4% from 2004, with 17% and 9% reductions, respectively, in combustion turbine and hydro production partially offset by increased coal-fired generation, primarily from Colstrip. Total generation met approximately 42% of PGE's retail load in 2005, compared to 43% in 2004.

The following table indicates PGE's total system load (including both retail and wholesale) for the last two years. Average variable power costs include wheeling and exclude unrealized gains and losses from derivative instruments and the effect of credits to purchased power and fuel costs related to PGE's power cost adjustment mechanisms, as discussed above.

Megawatt-Hours/Variable Power Costs

	Megawatt-Hours (thousands)		Average Variable Power Cost (Mills/KWh)	
	2005	2004	2005	2004
Generation	7,821	8,114	13.7	15.0
Term Purchases	11,705	12,017	35.3	30.9
Spot Purchases	1,361	1,343	57.4	41.4
Total System Load	20,887	21,474	31.3	28.2

Production, distribution, administrative and other expenses increased $21 million (8%) from 2004 due primarily to increased employee benefit expenses (including medical and pension costs), the settlement of certain asserted claims, and an increase in distribution and preventive maintenance expenses. These were partially offset by a reduction in maintenance and other expenses at the Company's thermal generating plants.

Income taxes related to utility operations decreased $11 million primarily due to lower pre-tax operating income.

Other Income (Miscellaneous) decreased $5 million due primarily to the establishment of a $10 million reserve related to the future refund to Multnomah County customers of previously-collected income taxes, pursuant to a settlement agreement. For further information, see "Class Action Lawsuit - Multnomah County Business Income Taxes" in "Financial and Operating Outlook" of this Item 7.

Capital Resources and Liquidity

Review of Cash Flow Statement

Cash Provided by Operations is used to meet the day-to-day cash requirements of PGE. Supplemental cash is obtained from external borrowings, as needed.

A significant portion of cash from operations consists of charges that are recovered in customer revenues for depreciation and amortization of utility plant that require no current period cash outlay. The recovery from customers of prior capital expenditures through depreciation and amortization provides a source of funding for current and future cash requirements. Cash flows from operations can also be affected by changes in the price of power and fuel as well as by weather conditions, as temperatures outside the normal range can affect electricity usage and resultant cash flow.

Cash provided by operating activities totaled $106 million in 2006 compared to $372 million provided by operating activities in 2005. The decrease was due primarily to a $119 million increase in power and fuel purchases and a $129 net decrease in cash collateral deposits received from certain wholesale customers. In addition, there was a $13 million increase in income tax payments and a $10 million refund of business income taxes to customers in Multnomah County, pursuant to a settlement agreement.

Investing Activities consist of new construction and improvements to PGE's distribution, transmission, and generation facilities. The $116 million increase in capital expenditures in 2006 is primarily due to construction costs of Port Westward and initial costs related to the Biglow Canyon Wind Farm. Other expenditures were related to the expansion of PGE's distribution system to support both new and existing customers within the Company's service territory.

Financing Activities provide supplemental cash for both day-to-day operations and capital requirements as needed. PGE relies on cash from operations, the issuance of commercial paper, borrowings under its revolving credit facility, and long-term financing activities to support such requirements.

In May 2006, PGE issued $275 million of First Mortgage Bonds, consisting of two series. One series, in the amount of $175 million, bears interest at an annual rate of 6.31% and will mature in 2036. The other series, in the amount of $100 million, bears interest at an annual rate of 6.26% and will mature in

2031. PGE used the proceeds from the bond issuances for the early retirement of the $150 million principal amount of 8 1/8% Series First Mortgage Bonds due in 2010, and for general corporate purposes. PGE also repaid $9 million of conservation bonds and retired $3 million of preferred stock during 2006.

PGE issued $81 million in short-term debt in 2006 and also paid cash dividends totaling $28 million on its common stock during the year. In 2005, PGE paid a common stock dividend of $150 million to Enron.

The issuance of additional First Mortgage Bonds and preferred stock requires PGE to meet earnings coverage and security provisions set forth in the Company's Articles of Incorporation and the Indenture of Mortgage and Deed of Trust securing the bonds. PGE estimates that on December 31, 2006 it could issue up to approximately $517 million of First Mortgage Bonds under the most restrictive issuance test in the mortgage. In addition, it is estimated that the Company could issue up to approximately $242 million in preferred stock under the restrictions set forth in the Articles of Incorporation. Any issuances would also be subject to market conditions and amounts may 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 mortgage on the basis of property additions, bond credits, and/or deposits of cash. Based on the availability of the short-term credit facility and the expected ability to issue long-term debt and equity securities, management believes there is sufficient liquidity to meet the Company's anticipated capital and operating requirements.

PGE has a $400 million five-year revolving credit facility with a group of commercial banks. The facility, which is unsecured, is used as backup for commercial paper borrowings and is available for general corporate purposes, with the maximum amount available to PGE for borrowings and/or the issuance of standby letters of credit. At December 31, 2006, PGE had $81 million of short-term commercial paper outstanding and had utilized approximately $6 million in letters of credit ($2 million related to wholesale trading activities and $4 million related to Port Westward), with approximately $313 million available for additional borrowings and/or letters of credit.

The credit facility allows PGE to 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 facility. A provision of the facility allows PGE to annually request that the termination date be extended for one additional year. Any request requires approval of a majority of the participating banks, with the termination date extended only for those banks approving the request. In July 2006, upon approval of all participating banks, the facility was amended to extend the termination date to July 14, 2011. The facility provides that all outstanding loans mature on the termination date of the facility. The facility requires annual fees based on PGE's unsecured credit ratings, and contains customary covenants and default provisions, including a requirement that limits consolidated indebtedness, as defined in the facility, to 65% of total capitalization. At December 31, 2006, the Company's consolidated indebtedness to total capitalization ratio, as calculated under the facility, was 46.3%.

PGE has authorization from the FERC to issue short-term debt, in an amount not to exceed $400 million outstanding at any one time, over the two-year period February 8, 2006 through February 7, 2008.

Cash Requirements

Access to short-term debt markets provides necessary liquidity to support PGE's current operating activities, including the purchase of electricity and fuel. Long-term capital requirements are driven largely by debt refinancing activities and capital expenditures for distribution, transmission, and generation facilities to support both new and existing customers.

PGE's liquidity and capital requirements can be significantly affected by operating costs, capital expenditures, debt service, and working capital needs, including margin deposits related to wholesale trading activity. PGE's revolving credit facility supplements operating cash flow and provides a primary source of liquidity. PGE's ability to secure sufficient long-term capital at reasonable cost is determined by its financial performance and outlook, capital expenditure requirements (including the effects of these factors on the Company's credit ratings), and alternatives available to investors. The Company's ability to obtain and renew such financing depends on its credit ratings as well as on bank credit markets, both generally and for electric utilities in particular.

PGE's financial objectives include the balancing of debt and equity to maintain a low weighted average cost of capital while retaining sufficient flexibility to meet the Company's financial obligations. PGE's objective is 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 53.0% and 57.5% at December 31, 2006 and December 31, 2005, respectively.

As previously indicated, a significant portion of cash provided by operations consists of depreciation and amortization of utility plant which is recovered in rates. PGE estimates recovery of such charges to approximate $180 million to $190 million annually over the period 2007-2009. Combined with all other sources, cash provided by operations is estimated to range from $280 million to $320 million annually during the 2007-2009 period.

The following table indicates PGE's projected primary cash requirements for the years indicated (in millions):

	2007	2008	2009
Capital expenditures (*)	$430 - $450	$250 - $270	$240 - $260
Long-term debt maturities	$66	-	-

(*) Includes expenditures related to Phase I of the Biglow Canyon Wind Farm (approximately $200 million for 2007), the construction of Port Westward (approximately $12 million for 2007), and fish passage measures at the Pelton Round Butte hydroelectric project (approximately $47 million for 2007 - 2009). Excludes expenditures related to the advanced metering infrastructure project, which remains subject to regulatory approval.

PGE's revolving credit facility may be used to fund any potential cash shortfall, with additional liquidity available, if necessary, from the issuance of long-term debt. In December 2006, the Company entered into an agreement with certain institutional buyers to issue $170 million of PGE's First Mortgage Bonds by June 1, 2007. (For additional information, see Note 7, Credit Facility and Debt, in the Notes to Financial Statements).

Cash balances are temporarily invested primarily in government money market funds and short-term commercial paper that have remaining maturities of less than three months from the date of acquisition. Such investments, which are considered cash equivalents, are consistent with PGE's investment objectives to preserve principal, maintain liquidity, and diversify risk, and are limited to investment grade securities (primarily short term).

Following the issuance of new PGE common stock, the Company paid a total of $28 million in dividends in 2006. In addition, the PGE Board of Directors on October 26, 2006 declared a quarterly common stock dividend of 22.5 cents per share that was paid on January 15, 2007. The Company expects to pay regular quarterly dividends on its common stock; however, the declaration of such dividends is at the discretion of the Company's Board of Directors and is not guaranteed. The amount of common dividends will depend upon PGE's results of operations and financial condition, future capital expenditures and investments, any applicable regulatory and contractual restrictions, and other factors that the Board of Directors considers relevant.

The OPUC order approving the issuance of new PGE common stock includes a stipulation containing several conditions, including a requirement that, after issuance of the new common stock, PGE cannot pay a dividend that would reduce the Company's common equity capital percentage below 48% of total capitalization (excluding short-term borrowings) without prior OPUC approval. The requirement is reduced to 45% when the DCR holds between 20% and 40% of the issued and outstanding common stock of PGE, with no minimum common equity capital percentage requirement when the DCR holds less than 20% of the issued and outstanding common stock of PGE. At February 1, 2007, the DCR held approximately 51% of the total outstanding common stock of PGE. Other conditions include a requirement that the OPUC be notified (simultaneously with the public) of any dividend declared by PGE's Board of Directors. Management believes that, at December 31, 2006, the Company has the ability to pay dividends, notwithstanding the above restrictions.

Credit Ratings

PGE's secured and unsecured debt are rated at investment grade by Moody's Investors Service (Moody's) and Standard and Poor's (S&P).

PGE's current credit ratings are as follows:

	Moody's	S&P
First Mortgage Bonds	Baa1	BBB+
Senior unsecured debt	Baa2	BBB
Preferred stock	Ba1	BBB-
Commercial paper	Prime-2	A-2
Outlook:	Stable	Negative

On November 10, 2006, Fitch Ratings affirmed PGE's existing ratings and announced that they would no longer provide ratings coverage for the Company. On January 29, 2007, S&P reaffirmed PGE's current credit ratings and outlook.

Should Moody's or S&P (or both) reduce the credit rating on PGE's unsecured debt to below investment grade, the Company could be subject to requests by certain of its wholesale counterparties to post additional performance assurance collateral. On January 31, 2007, PGE had posted approximately $26 million of collateral, consisting of $2 million in letters of credit and $24 million in cash. Based on the Company's non-trading portfolio, estimates of current energy market prices, and the current level of collateral outstanding, as of January 31, 2007, the approximate amount of additional collateral that could be requested upon a single agency downgrade event to below investment grade is approximately $57 million and decreases to approximately $8 million by year-end 2007. The approximate amount of additional collateral that could be requested upon a dual agency downgrade event to below investment grade is approximately $73 million and decreases to approximately $10 million by year-end 2007.

In addition to collateral calls, a credit rating reduction could impact the terms and conditions of long-term debt issued in the future. Any rating reductions could also increase interest rates and fees on PGE's revolving credit facility, increasing the cost of funding the Company's day-to-day working capital requirements. PGE's financing arrangements do not contain ratings triggers that would result in an acceleration of the required interest and principal payments in the event of a ratings downgrade. Management believes that the Company's existing line of credit, access to the commercial paper market, and cash from operations provide it with sufficient liquidity to meet its day-to-day cash requirements.

Contractual Obligations and Commercial Commitments

The following indicates PGE's contractual obligations as of December 31, 2006 (in millions):

	Payments Due (*)						
	Total	2007	2008	2009	2010	2011	After 2011
Long-Term Debt	$ 1,003	$ 66	$ -	$ -	$ 186	$ -	$ 751
Short-Term Debt	81	81	-	-	-	-	-
Interest on Long-Term Debt	973	61	59	59	49	46	699
Operating Leases	265	8	8	7	7	8	227
Purchase Obligations	263	221	34	6	2	-	-
Purchased Power and Fuel:							
Electricity Purchases	1,736	665	214	77	78	77	625
Capacity Contracts	210	23	23	23	23	23	95
Natural Gas Agreements	181	34	21	21	19	16	70
Public Utility Districts	94	8	8	9	7	7	55
Coal and Transportation Agreements	47	13	14	4	4	4	8
Total	$ 4,853	$ 1,180	$ 381	$ 206	$ 375	$ 181	$ 2,530

(*) Future interest on long-term debt is calculated based on the assumption that all debt is outstanding until maturity. For debt instruments with variable rates, interest is calculated for all future periods using the rates in effect at December 31, 2006. Contributions to the Company's pension plan are estimated at zero for 2007 through 2011 and not determinable thereafter. Purchase Obligations in 2007 includes $150 million related to the Biglow Canyon Wind Farm.

Other Financial Obligations

PGE has entered into long-term power purchase contracts with certain public utility districts in the state of Washington under which PGE 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, Wanapum 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 project, PGE would be allocated up to a cumulative maximum of 7% of the total project.

For details of annual costs by project, including debt service, see Note 9, Commitments and Guarantee, in the Notes to the Financial Statements.

Off-Balance Sheet Arrangements

PGE is not engaged in any off-balance sheet arrangements through unconsolidated limited purpose entities.

Critical Accounting Policies and Estimates

A critical accounting policy is one that is both important to results of operations and financial condition and requires management to make critical accounting estimates. An accounting estimate is an approximation made by management of a financial statement component or account. Accounting estimates reflected in PGE's financial statements measure the effects of past business transactions or events, or the present status of an asset or liability. Accounting estimates included in the accounting policies described below require assumptions about matters that are highly uncertain at the time the estimate is made. Additionally, different estimates that could have been used, or changes in an accounting estimate that are reasonably likely to occur, could have a material impact on the financial statements. The inherent uncertainty of some matters can make judgments subjective and complex. The effects of estimates and assumptions related to future events cannot be made with certainty. PGE's estimates are based upon historical experience and on assumptions that management believes to be reasonable in the circumstances. These estimates may change with changes in events, information, experience, and the Company's operating environment. The following critical accounting policies and estimates are those used in the preparation of PGE's consolidated financial statements.

Regulatory Accounting

As a regulated utility, PGE prepares its consolidated financial statements in accordance with the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, Accounting for the Effects of Certain Types of Regulation. In order to apply the accounting policies and practices of SFAS No. 71, regulated companies must satisfy the following conditions: (i) rates are established by or subject to approval by an independent regulator; (ii) rates are designed to recover specific costs of delivering service; and (iii) in view of demand for service, it is reasonable to assume that rates can be charged and collected from customers at levels that will recover the Company's costs. SFAS No. 71 requires companies that meet these conditions to reflect the impact of regulatory decisions in their consolidated financial statements and requires that certain costs be deferred as regulatory assets until matching revenues are recognized. Similarly, certain items may be deferred as regulatory liabilities and amortized to the income statement as rates to customers are reduced.

PGE continues to meet each of above conditions for continued application of SFAS No. 71 in its financial statements. The Company is subject to jurisdiction of the OPUC, which approves PGE's retail rates, ensuring that they provide an opportunity for the Company to earn a fair return on its investment. The Company's rates, as authorized by the OPUC, are based on the cost of service and are designed to recover operating expenses and capital costs associated with generation, transmission and distribution assets used to provide regulated service to customers. Although changes in such rates are subject to a formal ratemaking process, it is expected that the OPUC will continue to recognize all prudently-incurred costs and authorize rates that allow for their recovery.

PGE's retail operations are conducted within a state-approved service area in which there is no retail competition, other than that related to the state's customer choice program. Participation in this program, implemented in 2002, has not had a material impact on PGE's regulated operations, with only about 5% of the Company's total retail load served by ESSs. The large majority of PGE's customers continue to take service under rate tariffs determined by the cost of service. Changes in demand and level of competition for PGE's regulated services have not materially impacted the Company's ability to recover its costs through regulation.

PGE periodically assesses the continued applicability of SFAS No. 71 to its business, considering both the current and anticipated future rate environment and related accounting guidance, as outlined in SFAS No. 101, Regulated Enterprises - Accounting for the Discontinuation of Application of SFAS No. 71, and Emerging Issues Task Force Issue 97-4, Deregulation of the Pricing of Electricity - Issues Related to the Application of SFAS No. 71 and SFAS No. 101. As PGE continues to fully meet each of the required conditions, the Company has recorded regulatory assets and liabilities to reflect their expected full recovery or refund in customer rates.

If future recovery of costs ceases to be probable, however, PGE would be required to write off these regulatory assets and liabilities. In addition, if at some point in the future PGE determines that all or a portion of its utility operations no longer meet the criteria for continued application of SFAS No. 71, the Company would be required to adopt the provisions of SFAS No. 101, which would require the Company to write off those regulatory assets and liabilities related to operations that no longer meet requirements of SFAS No. 71. Discontinuation of SFAS No. 71 could have a material impact on the Company's results of operations and financial position.

Asset Retirement Obligations

SFAS No. 143, as interpreted by FASB Interpretation No. 47, requires the recognition of Asset Retirement Obligations (AROs), measured at estimated fair value, for legal obligations related to dismantlement and restoration costs associated with the retirement of tangible long-lived assets in the period in which the liability is incurred. 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 are depreciated over the life of the related asset, with accretion of the ARO liability classified as an operating expense on the Statement of Income. On the Statement of Income, AROs related to Utility plant are included in Depreciation and Amortization expense, with those related to Other property included in Other Income (Deductions). In accordance with requirements of SFAS No. 143, accumulated asset retirement removal costs that do not qualify as AROs have been reclassified from Accumulated depreciation to Regulatory liabilities on the Consolidated Balance Sheets.

Trojan Decommissioning

In early 1993, PGE ceased commercial operation of Trojan and began the decommissioning process. The original Trojan decommissioning cost estimate was prepared by an engineering firm with subsequent updates by PGE, due primarily to the effects of inflation and the timing of certain activities. The net estimated liability for Trojan decommissioning costs as of December 31, 2006 was $108 million, measured at estimated fair value pursuant to provisions of SFAS No. 143. PGE's retail prices, as authorized by the OPUC in January 2007, include recovery of $4.65 million annually. These amounts are deposited in an external trust fund, which reimburses PGE for costs expended under the decommissioning plan. Decommissioning cost estimates include equipment removal, embedded pipe remediation, surface decontamination, non-radiological decontamination, and on-site spent nuclear fuel storage until permanent storage is provided by the USDOE. Estimating the cost of decommissioning activities over a period extending to 2031 is inherently subjective and complex. Such estimates may vary because of changes in regulatory requirements, technology, labor and material costs, and waste burial. In addition, timing of actual activities may differ from that established in the decommissioning plan, which may also cause actual costs to vary from those estimated. Remaining decommissioning activities consist of demolition of the existing structures and long-term operation and decommissioning of the Independent Spent Fuel Storage Installation.

Management does not expect actual future decommissioning costs to change significantly from the current estimate. However, if actual costs significantly exceed the previously estimated amount, funds collected through rates may not be adequate to cover actual decommissioning costs and may require that PGE utilize available cash and a credit facility to advance funds to the trust to cover any near term shortfall. Recovery of any such shortfall from customers would require OPUC approval.

Loss Contingency Reserves

Contingencies are evaluated based on SFAS No. 5, Accounting for Contingencies, 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 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 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. Reserves established reflect management's assessment of inherent risks, credit worthiness, and complexities involved in the collection process.

Receivables and Refunds - California Wholesale Market

As of December 31, 2006, PGE has net accounts receivable balances totaling approximately $63 million for wholesale electricity sales made to the California Independent System Operator (ISO) and the California Power Exchange (PX) from November 2000 through February 2001. The Company estimates that the majority of this amount was for sales by the ISO and PX to Southern California Edison Company and Pacific Gas & Electric Company. In 2001, the PX filed for bankruptcy and Pacific Gas & Electric Company filed a voluntary petition for relief under the provisions of Chapter 11 of the federal Bankruptcy Code. Although both entities have emerged from their bankruptcy proceedings as reorganized debtors, not all claims filed in the proceedings, including those filed by PGE, have been resolved.

In 2002, the FERC ordered refunds for non federally-mandated transactions made between October 2, 2000 and June 20, 2001 in the spot markets operated by the ISO and PX. A methodology to calculate such refunds was also established by the FERC. The FERC has indicated that any potential refunds can be offset by accounts receivable, thereby mitigating the effect of potential refunds on PGE. Calculated interest on potential refunds will likewise be offset by interest on accounts receivable.

The FERC methodology for calculating potential refunds, initially established in July 2001, was revised in March 2003, significantly increasing the refund amount initially estimated. Accordingly, a $17.5 million reserve established at December 31, 2002 was increased to $40 million at December 31, 2003. Pursuant to FERC guidelines, PGE in September 2005 filed a cost recovery study to prove that the Company, in order to cover its costs, should be permitted to recover additional revenues in excess of the mitigated prices. By order issued November 2, 2006, the FERC accepted, subject to PGE making certain additional revisions, a revised cost recovery study that had been filed by PGE in response to an earlier January 26, 2006 order. Pursuant to the November 2, 2006 order, PGE filed a final cost study with the ISO that now reflects an approximate $19.8 million cost offset to its refund obligation. Third parties have challenged PGE's cost recovery filings and made numerous requests that they be rejected in their entirety or that the cost offset be reduced to zero. PGE has filed responses to those challenges.

PGE believes that the FERC erred in certain findings in its orders regarding PGE's cost recovery, and has filed requests for rehearing as to several issues in those orders. Due to the continuing uncertainty related to these matters, PGE has made no adjustment to the $40 million reserve previously established for the Company's potential liability. As an unresolved legal and regulatory matter, both the refund methodology and estimated amount may vary significantly in the future, which could have a material impact on PGE's results of operations.

Price Risk Management

PGE engages in price risk management activities in its electric business, utilizing derivative 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 and to minimize net power costs for retail customers. Derivative contracts are accounted for under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended.

In its January 2007 general rate order, the OPUC approved a new PCAM by which PGE can adjust future rates to reflect the difference between each year's forecasted and actual net variable power costs on a settlement basis. Effective December 2006, PGE began to apply SFAS No. 71 to all derivative instruments to reflect the effects of regulation. As a result, a regulatory asset or regulatory liability is recorded to offset changes in fair value of instruments not included in the Resource Valuation Mechanism (RVM). Prior to December 2006, changes in fair value for these instruments were not offset by a regulatory asset or regulatory liability unless those contracts were previously included in rates under the RVM or were expected to be included in future rates under the RVM. Effective January 17, 2007, a new Annual Power Cost Update Tariff replaced the RVM. For further information, see "Resource Valuation Mechanism" and "General Rate Case" in "Financial and Operating Outlook" of this Item 7.

Mark-to-Market

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 earnings 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 contracts 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 is the difference between the premium paid or received and 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 could have a material impact on PGE's financial condition and results of operations.

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. At December 31, 2006, the plan's assets were comprised of approximately 67% equity securities and 33% debt securities.

Changes in actuarial assumptions can also materially affect net periodic pension expense. A 0.25% reduction in the expected long-term rate of return on plan assets would have increased 2006 pension expense by approximately $1.2 million. A 0.25% reduction in the discount rate would have increased 2006 pension expense by approximately $1.6 million.

Utility Rate Treatment of Income Taxes

In 2005, the State of Oregon adopted SB 408, a law that adjusts the way that PGE and other Oregon investor-owned electric and gas utilities recover income tax expense from customers through revenues for utility services. The law authorizes an adjustment to retail customer rates based on the difference between "taxes authorized to be collected" and "taxes paid" to governmental entities on or after January 1, 2006. In September 2006, the OPUC adopted permanent rules to implement SB 408. As a result of its assessment of the rules, PGE has estimated potential refunds to customers of approximately $42 million for 2006, including $2 million of accrued interest. PGE will continue to evaluate its options for changing or modifying the legislation and rules, and challenging any adjustment that follows for the 2006 tax year. For further information, see "Utility Rate Treatment of Income Taxes" in "Financial and Operating Outlook" of this Item 7.

Transactions with Related Parties

PGE services to affiliated companies consist primarily of employee and administrative services. Transactions with affiliated companies are subject to regulation by the OPUC. Most affiliated interest transactions are made under a Master Service Agreement filed with the OPUC. Under OPUC regulations, services provided to affiliates by PGE are charged at the higher of cost or market, while affiliated services received by PGE are charged at the lower of cost or market. Services with affiliated companies in 2006 were not material.

Financial and Operating Outlook

Retail Customer Growth and Energy Deliveries

Weather adjusted retail energy deliveries to PGE and ESS customers increased 2.7% in 2006 compared to 2005, with deliveries to residential, commercial, and industrial customers increasing by 2.4%, 3.0%, and 2.6%, respectively. The increase for residential customers resulted primarily from an 11,800 increase in the average number of customers served during the year. The increase for commercial and industrial customers resulted from a 1,700 increase in customers served, higher average use, and an improved economy. PGE forecasts total weather adjusted energy deliveries to PGE and ESS customers to increase by approximately 1.2% in 2007.

Power and Fuel Supply

Wholesale power market products, along with PGE's base of thermal and hydroelectric generating capacity, currently provide the Company the flexibility to respond to seasonal fluctuations in the demand for electricity from its retail and wholesale customers. Although surplus generation has diminished in recent years due to economic and population growth in the western United States, the recent construction of new generating plants has increased the region's capacity to meet its power needs. The Company anticipates that an active wholesale market and generating capacity within the Western Electricity Coordinating Council will provide wholesale energy to supplement its generation and purchases under existing firm power contracts.

Early forecasts indicate that regional hydro conditions will be near normal in 2007. Volumetric water supply forecasts for the Pacific Northwest (as of February 15, 2007), prepared by the Northwest River Forecast Center in conjunction with the Natural Resources Conservation Service and other cooperating agencies, indicate the projected January-to-September 2007 runoff (as measured at The Dalles, Oregon) at 94% of normal, compared to actual runoffs of 107% in 2006 and 74% in 2005. In 2007, hydro conditions in both the Clackamas and Deschutes river systems, where PGE's hydro facilities are located, are currently projected to be 97% and 98% of normal, respectively, compared to actual runoffs of 92% and 100% of normal, respectively, in 2006 and 72% and 87% of normal, respectively, in 2005.

PGE generated 37% of its retail load requirement in 2006, with 27% met with thermal generation and the remainder met with hydro generation. Short- and long-term purchases were utilized to meet the remaining load. PGE's ability to purchase power in the wholesale market, along with the Company's base of thermal and hydroelectric generating capacity, currently provides the flexibility to respond to seasonal fluctuations in the demand for electricity both within its service territory and from its wholesale customers.

Factors that can affect the availability and price of purchased power and fuel include weather conditions in the Northwest and Southwest, the performance of major generating facilities in both regions, regional hydro conditions, and prices of natural gas and coal used to fuel thermal generating plants. Market prices of natural gas can also be affected by destructive storms and extreme weather in other sections of the United States and Canada. Power and natural gas prices have moderated since late 2005, due primarily to increased hydro availability within the region and a relatively quiet hurricane season in the Gulf of Mexico, in contrast to 2005.

Price Risk Management - As PGE's primary business is to serve its retail customers, it uses derivative instruments to manage its exposure to commodity price risk and to minimize net power costs to serve customers. Under SFAS No. 133, as amended, PGE records unrealized gains and losses in earnings in the current period for derivative instruments that do not qualify for either the normal purchases and normal sales exception or cash flow hedge accounting. Derivative instruments that qualify for the normal purchases and normal sales exception are recorded in earnings on a settlement basis, and cash flow hedges are recorded in Other Comprehensive Income (OCI) until they can offset the related results on the hedged item in the income statement. The timing difference between the recognition of unrealized gains and losses on certain derivative instruments (see discussion of RVM and PCAM below) and their realization and subsequent recovery in rates is recorded as a regulatory asset or regulatory liability to reflect the effects of regulation under SFAS No. 71.

From the time prices were set in the RVM process until the January 16, 2007 end of the RVM period, any changes to electricity and natural gas prices used in the RVM resulted in unrealized gains and losses that were recorded in earnings for existing and new derivative instruments that did not qualify for the normal purchases and normal sales exception or cash flow hedges. As a result, this timing difference created earnings volatility between reporting periods. The earnings volatility has been reduced with the adoption of a PCAM by the OPUC.

In its January 2007 general rate order, the OPUC approved a new PCAM by which PGE can adjust future rates to reflect the difference between each year's forecasted and actual net variable power costs on a settlement basis. Effective December 2006, PGE began to apply SFAS No. 71 to all derivative instruments to reflect the effects of regulation. Prior to December 2006, changes in the fair value of instruments not included in the RVM were not offset by a regulatory asset or regulatory liability.

In 2006, PGE adopted a "medium term" power cost strategy to better respond to changing energy market conditions. By extending the period in which the Company may take positions in power and fuel markets from 24 months to up to five years, PGE expects to reduce price volatility for its customers during the next three- to five-year period. Accordingly, PGE has amended its risk limits for the projected impact of the medium term strategy on the Company's net open position.

Ownership of PGE

In accordance with Enron's Chapter 11 Plan, on April 3, 2006, PGE issued 62.5 million shares (of 80 million, no par value, shares authorized) of new PGE common stock. Approximately 27 million shares of the new PGE common stock were initially issued to the Debtors' creditors holding allowed claims, and approximately 35.5 million shares were issued to the DCR, where the shares will be held to be released over time to the Debtors' creditors holding allowed claims, in accordance with the Chapter 11 Plan. Since the initial distribution, approximately 3.5 million shares of PGE common stock have been released from the DCR, with approximately 32 million shares held in the DCR as of February 1, 2007. The 42.8 million shares of PGE common stock previously held by Enron were cancelled. Following issuance of the new PGE common stock, PGE ceased to be a subsidiary of Enron. The new PGE common stock is listed on the New York Stock Exchange under the ticker symbol POR.

The registered owner of the new PGE common stock held in the DCR is the Disbursing Agent associated with the DCR. The Disbursing Agent oversees the release of new PGE common stock from the DCR to the Debtors' creditors that hold allowed claims. All shares of new PGE common stock held in the DCR will be voted by the Disbursing Agent at the direction of the Disputed Claims Reserve Overseers, which is currently comprised of those individuals who serve on Enron's Board of Directors.

The OPUC order approving the distribution of the new PGE common stock includes 17 conditions that relate to, among other things: certain service quality measures; additional direct access options for commercial and industrial customers; maintenance of PGE's financial strength during the conclusion of the Enron bankruptcy process; and certain indemnifications for PGE from Enron related to Enron-sponsored employee benefit plans and certain liabilities related to taxes that may be imposed as the result of PGE's inclusion in Enron's consolidated tax group. These indemnifications are included in the separation agreement described below.

On February 10, 2006, the City of Portland appealed the OPUC order approving the distribution of new PGE common stock in both the Marion County Circuit Court and the Oregon Court of Appeals. On July 19, 2006, the Court of Appeals granted an OPUC motion to dismiss the action before that Court and, on November 2, 2006, the Marion County Circuit Court dismissed the case upon the request of the City of Portland.

Separation Agreement - On April 3, 2006, PGE and Enron entered into a separation agreement, as required by the OPUC order that approved the distribution of new PGE common stock. The separation agreement provides generally for the settlement of intercompany amounts, the termination of intercompany agreements between PGE and Enron (except for certain provisions of a previously executed separate tax allocation agreement), and certain indemnifications for PGE from Enron related to Enron-sponsored employee benefit plans and certain liabilities related to taxes that may be imposed as the result of PGE's inclusion in Enron's consolidated tax group.

Release from Enron Pension Plan Liability - On May 8, 2006, the Pension Benefit Guaranty Corporation (PBGC) and PGE entered into a release with respect to the Enron Corp. Cash Balance Plan and the pension plans of other Enron debtor subsidiaries (Pension Plans). The PBGC irrevocably and unconditionally forever released, acquitted and discharged PGE and its subsidiaries and affiliates and each of their past and present officers, agents, directors, employees and representatives from all liability under Title IV of the Employee Retirement Income Security Act of 1974 with respect to the Pension Plans.

Oregon Tax Credits - PGE generated approximately $15 million of Oregon tax credits that, due to taxable income limitations, were not utilized by Enron prior to the separation of the two companies on April 3, 2006. In prior years, PGE was able to utilize these tax credits to reduce its tax payment obligation to Enron pursuant to a tax sharing agreement. Uncertainties exist with respect to the timing and ability by Enron to utilize the credits. To the extent that Enron is unable to utilize these credits on its tax returns, PGE expects that it will be able to utilize such tax credits on its Oregon income tax returns in periods subsequent to its separation from Enron. Any amounts not utilized by PGE on its Oregon income tax return for the period April 3, 2006 through December 31, 2006 are expected to be available for carryover and utilization in future years. PGE had quarterly income tax payments due to the State of Oregon during 2006. A portion of the tax credits was utilized to offset these liabilities with no effect on income. Any realization of these tax credits will be reflected as an adjustment to equity.

Resource Valuation Mechanism

PGE's RVM tariff mechanism was used to update the Company's net variable power costs for inclusion in base rates from 2003 through January 16, 2007. It utilized a combination of market prices and the value of the Company's resources to establish power costs and set prices for energy services. Based upon projections of net variable power costs contained in PGE's RVM filings covering the last three years, the OPUC authorized average retail price increases of 0.4% for 2004, 1.4% for 2005, and 3.7% for 2006. Such adjustments increased the Company's revenues by approximately $4 million in 2004, $17 million in 2005, and $47 million in 2006. Based upon projections in PGE's 2007 RVM filing (which was consolidated with the Company's general rate case filing), the OPUC authorized an approximate 5.1% average retail price increase for 2007, which is expected to increase PGE's 2007 revenues by approximately $74 million.

General Rate Case

In March 2006, PGE filed a general rate case and proposed tariffs with the OPUC that would increase rates by 8.9%, providing for approximately $143 million in additional revenues and a 10.75% return on equity, based on a 56% equity capital structure. The proposed increase related to increases in power and fuel costs (as included in the Company's RVM process), general costs, and recovery of PGE's investment in Port Westward. The filing was the Company's first general rate increase request since 2001.

On January 12, 2007, the OPUC issued an order approving an overall price increase of approximately 1.3%, which will be allocated to all PGE customer classes. The increase represents the combined effect of a 2.8% increase related to cost recovery of Port Westward, to become effective when the plant goes into service, expected to be in late April 2007, and a 1.4% decrease related to general costs, which became effective on January 17, 2007. The decrease related to general costs primarily reflects reductions in forecasted test year costs and the effects of decisions related to the cost of capital. The OPUC previously approved a 5.1% price increase for increased power and fuel costs in PGE's RVM filing, which became effective on January 1, 2007. The change in retail prices is based upon a 50% equity capital structure, a 10.1% return on equity (ROE), and an overall rate of return of 8.29%. The overall increase in annual revenues approved by the OPUC for 2007 for the RVM, the general rate case, and Port Westward proceedings was $94.6 million, or 6.4%. The OPUC also established a process for reexamining the Port Westward rate increase if the plant in service date is delayed beyond April 29, 2007.

The OPUC also approved a process by which PGE can continue to adjust prices to reflect power cost variations in future years. An Annual Power Cost Update Tariff, which replaces the RVM, provides for rate adjustments to reflect updated forecasts of net variable power costs (NVPC) for future calendar years. PGE's initial filing under this Tariff, to be submitted to the OPUC by April 1, 2007, will include a forecast of NVPC, and any changes in retail prices, for 2008. In addition, a new PCAM provides for annual rate adjustments that reflect a portion of the difference between each year's actual NVPC and that forecast in the Annual Power Cost Update. The PCAM provides for application of an earnings test that will allow PGE to recover, or require the Company to refund, up to 90% of the difference between actual and forecast power costs, depending upon how much PGE's actual earnings vary from the Company's allowed ROE. The PCAM will produce a possible refund to customers of 90% of the amount by which actual NVPC is less than forecasted NVPC in excess of an amount equal to 75 basis points of PGE's ROE. For 2007, 75 basis points of ROE will be determined as a function of the in service date of Port Westward. Prior to Port Westward, the annualized impact of 75 basis points of ROE is $10.7 million. After Port Westward's in service date, the annualized impact of 75 basis points of ROE is $12.4 million. The PCAM will produce a possible collection from customers of 90% of the amount by which actual NVPC is greater than forecasted NVPC in excess of an amount equal to 150 basis points of PGE's ROE. For 2007, 150 basis points of ROE will be determined a function of the in service date of Port Westward. Prior to Port Westward, the annualized impact of 150 basis points of ROE is $21.4 million. After Port Westward's in service date, the annualized impact of 150 basis points is $24.8 million. A refund will occur only to the extent that it results in PGE's actual ROE for that year being no less than 100 basis points above the Company's last 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 100 basis points below the Company's last authorized ROE.

Utility Rate Treatment of Income Taxes

In 2005, the Oregon legislature passed a law that adjusts the way that PGE and other Oregon investor-owned electric and gas utilities recover income tax expense from customers through revenues for utility services. The law, commonly referred to as SB 408 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 utilities or their consolidated group. The new law requires that utilities file a report with the OPUC each year regarding the amount of taxes paid by the utility or its consolidated group (with certain adjustments), as well as the amount of taxes authorized to be collected in rates, as defined by the statute. This report is to be 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 establish an "automatic adjustment clause" to adjust rates. The first adjustment under the automatic adjustment clause applies only to taxes paid to units of government and collected from customers on or after January 1, 2006.

On September 14, 2006, the OPUC issued a final order (Final Order) that adopted permanent rules (Rules) to implement SB 408. In the Rules, the OPUC adopted the use of fixed reference points for margins and effective tax rates from a ratemaking proceeding. The OPUC also adopted a methodology to determine the amounts properly attributed to the utility from a consolidated tax payment using a formula to determine the ratio of the utility's payroll, property and sales to the consolidated group's amounts for the same items. This ratio is then multiplied by the amount of total taxes paid by the consolidated group to determine the utility's attributed portion. The OPUC also determined that interest should begin to accrue beginning January 1, 2006 using a mid-year convention for differences between income taxes collected and income taxes paid to governmental entities for tax year 2006.

In the Final Order, the OPUC addressed the so-called "double whammy" effect wherein the application of the Rules can result in unusual outcomes in certain situations. If a utility incurs higher expenses or receives lower revenues, resulting in lower taxes paid than the OPUC assumed it would incur in its last rate case, the automatic adjustment clause under SB 408 will require the utility to make a refund to customers and decrease the utility's earnings. Conversely, if a utility incurs lower expenses or receives higher revenues, resulting in higher taxes paid than the OPUC assumed it would incur in its last rate case, the automatic adjustment clause under SB 408 will surcharge customers and increase the utility's earnings. The OPUC stated in the Final Order that it will be responsive to concerns related to the consequences of the "double whammy" problem, and may address those concerns in other regulatory proceedings; however, it did not provide clear guidance on avenues of relief.

On December 30, 2005, PGE filed with the OPUC an application for deferred accounting to prevent either the financial enrichment or financial harm to the Company should the rules implementing SB 408 include the use of fixed reference points for margins and effective tax rates from a ratemaking proceeding. The Rules do use fixed reference points for margins and effective tax rates from a ratemaking proceeding. The deferred amount would reflect the tax effect of the difference between

PGE's implied operating costs under a fixed margin assumption and the Company's actual operating costs. In an interim order in the rulemaking process, the OPUC indicated that it would review deferral applications related to SB 408 on a case-by-case basis, but would view such applications with skepticism.

Effective with the April 3, 2006 issuance of new PGE common stock, PGE is no longer a subsidiary of Enron and files its own consolidated tax returns and remits payments directly to taxing authorities. However, in April 2006, PGE paid $17 million to Enron for net current taxes payable for the first quarter of 2006 when PGE was still included in Enron's consolidated group for filing consolidated federal and state income tax returns. Under the Rules, PGE will likely be required to refund to customers the majority of that amount.

As a result of its assessment of the Rules, PGE has estimated its potential refunds to customers to be approximately $42 million (including $2 million of accrued interest) for 2006 and has recorded a (pre-tax) reserve of such amount for the year. In accordance with the statute, the Company will file a report with the OPUC by October 15, 2007 for the 2006 tax year regarding the amount of taxes paid by the Company as well as the amount of taxes authorized to be collected in rates, as defined by the statute. Any refunds to customers for the 2006 tax year would begin after June 1, 2008.

PGE will continue to evaluate its options for changing or modifying the legislation and Rules, and challenging any adjustment that follows for the 2006 tax year.

Complaint and Application for Deferral - Income Taxes

On October 5, 2005, the Utility Reform Project and Ken Lewis (Complainants) filed a Complaint with the OPUC alleging that, since September 2, 2005 (the effective date of SB 408), PGE's rates are not just and reasonable and are in violation of SB 408 because they contain approximately $92.6 million in annual charges for state and federal income taxes that are not being paid to any government. The Complaint requests that the OPUC order the creation of a deferred account for all amounts charged to ratepayers 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.

Also on October 5, 2005, the Complainants filed an Application for Deferred Accounting with the OPUC, claiming that PGE is charging ratepayers $92.6 million annually for federal and state income taxes that are not being paid, and that such charges are not fair, just and reasonable. The Application for Deferred Accounting requests that the portion of PGE's revenue representing estimated PGE liabilities for federal and state income taxes, less any amounts of federal and state income taxes paid by PGE or on behalf of PGE, be deferred for later incorporation in rates. PGE opposes the deferral and has moved to dismiss the Complaint.

On July 10, 2006, the OPUC commenced proceedings on the Complaint and Deferral. Management cannot predict the ultimate outcome of this matter or estimate any potential loss.

Class Action Lawsuit - Multnomah County Business Income Taxes

In January 2005, David Kafoury and Kafoury Brothers, LLC filed a class action lawsuit in Multnomah County Circuit Court against PGE on behalf of all PGE customers who were billed on their electric bills and paid amounts for Multnomah County Business Income Taxes (MCBIT) after 1996 that the plaintiffs alleged were never paid to Multnomah County. The plaintiffs sought judgment against PGE for restitution of MCBIT in excess of $6 million, plus interest, recoverable costs, punitive damages, and attorney fees.

On July 28, 2006, the Multnomah County Circuit Court approved a settlement providing for PGE refunds and payments totaling $10 million, inclusive of interest and plaintiffs' attorney fees, costs, and expenses as approved by the Court's final order. The settlement includes no admission of liability or wrongdoing by the Company. PGE established a reserve of $10 million in 2005 related to the settlement. Refunds to customers were completed in the fourth quarter of 2006.

City of Portland Actions

The City of Portland has indicated that it may pursue ratemaking for PGE's retail customers who reside within the City of Portland's boundaries. In September 2005, the Portland City Council approved a resolution directing the City Attorney and City staff to obtain from PGE information regarding the collection and payment of utility income taxes. PGE voluntarily provided extensive financial and operational data to the City of Portland. The City of Portland subsequently broadened its inquiry to include PGE's power trading activities in 2000 and 2001 and requested that PGE provide many additional documents and records, and on March 23, 2006 issued a subpoena to PGE seeking numerous records and documents. PGE determined that there are a number of legal and practical issues concerning the City of Portland's subpoena and other requests for additional information, and has declined to provide any additional data to the City of Portland while those issues remain unresolved. On April 21, 2006, PGE filed a complaint in Multnomah County Circuit Court seeking clarity on whether the City of Portland has investigatory and ratemaking authority. The City of Portland has agreed not to seek enforcement of the subpoena while this case is pending.

On May 5, 2006, the City of Portland filed a complaint against PGE with the OPUC. The complaint alleged that Enron and PGE should not have filed income taxes on a unitary basis under Oregon law. The complaint also alleged that PGE made certain cash payments to Enron under a tax allocation agreement which at the time had not been approved by the SEC, and that PGE did not submit the agreement to the OPUC for a determination as to whether the agreement was fair and reasonable and in the public interest as required under Oregon law.

On July 31, 2006, the OPUC dismissed the claims related to unitary basis tax filing and SEC approval of the tax allocation agreement. On August 16, 2006, PGE filed a motion for summary judgment seeking dismissal of the remaining claims, which the OPUC granted on November 17, 2006.

Boardman Coal Plant - Repair Outages

On October 22, 2005, Boardman was taken out of service to repair its steam turbine rotor. On February 6, 2006, during the process of returning the plant to operation, the generator rotor was damaged and subsequently removed for repair. The generator rotor was repaired and the plant was operational in late May. In early June, the plant was again taken out of service for repairs to its low pressure turbine unit; upon completion of these repairs, the plant returned to full operation on July 1, 2006.

The extended outages of Boardman required that PGE replace its portion of the plant's generation with both higher cost purchases in the wholesale market and increased generation from the Company's natural gas-fired generating plants. Incremental power costs during the plant's outages totaled approximately $92 million, including $44 million in the first quarter and $8 million in the second quarter of 2006. Reduced replacement power costs in the second quarter of 2006 reflect the impact of favorable regional hydro conditions on wholesale power prices.

On November 18, 2005, PGE filed with the OPUC an "Application for Deferred Accounting of Excess Power Costs Due to Plant Outage." The application requested an order authorizing PGE to defer for later ratemaking treatment excess power costs associated with that portion of Boardman's outage related to repair of the plant’s steam turbine rotor and covered the period from the November 18, 2005 application date through February 5, 2006. The application requested deferral of approximately $46 million, representing the difference between Boardman's variable power costs used in setting rates for 2005 and 2006 (under PGE's RVM) and replacement power costs incurred during the outage. Based upon prior OPUC actions, the stated position of the OPUC staff in the proceeding, and considering both applicable accounting guidance and the impact of SB 408 on any benefit received by the Company, PGE recorded a deferral in the amount of $6 million at December 31, 2006.

On February 12, 2007, the OPUC issued an order authorizing PGE to defer for future rate recovery $26.4 million of excess power costs resulting from Boardman’s extended outage. Amortization will be determined in a future ratemaking proceeding that will include a prudency review of PGE’s actions with respect to the outage and acquisition of replacement power and a determination as to whether recovery of the deferred amount will cause PGE’s earnings to exceed a reasonable range. In its order, the OPUC indicated that the outage was significant, unique and outside the foreseen range of risk for forced outages. The order reduced PGE’s estimate of the total net cost of the outage (the amount eligible for deferral) to approximately $42.8 million. The OPUC imposed a sharing mechanism that divides responsibility for the outage costs between PGE’s customers and shareholders and that also includes an adjustment related to the effects of SB 408. Under the applicable accounting standards, the $20.4 million difference between the $26.4 million authorized deferral and the $6 million recorded in 2006 will be recorded in 2007.

Under the RVM process, a 4-year rolling average of historical forced outages of PGE's generating plants was used in projecting plant availability and expected power costs. In its January 12, 2007 general rate case order, the OPUC approved a 4-year rolling average forced outage rate for Boardman that excluded the 2005 portion of the outage covered by the November 18, 2005 deferral application. PGE did not file an application to defer incremental power costs related to the generator rotor outage or the low pressure turbine outages (February 6, 2006 through June 6, 2006) and will not propose the inclusion of these outages in the 4-year rolling average of forced outages in its annual power cost update filings starting in 2008 or in future general rate case proceedings.

Port Westward Generating Plant

In February 2005, pursuant to PGE's strategy to meet the electric energy needs of its customers outlined in its Integrated Resource Final Action Plan, PGE began construction of Port Westward, a 400 MW natural gas-fired facility located in Clatskanie, Oregon. Construction is proceeding, with the plant expected to go into service in late April 2007. Total cost of the plant is estimated at between $275 million and $295 million, including Allowance for Funds Used During Construction (AFDC).

Biglow Canyon Wind Farm

In accordance with PGE's plan to acquire additional wind generation, as outlined in its IRP, the Company is proceeding with construction of the Biglow Canyon Wind Farm, located in Sherman County, Oregon. PGE currently plans to construct the project in three phases over a five-year period. The first phase of the project, which will be owned and operated by PGE, will have a capacity of 125 MW. It is expected to be completed by the end of 2007 at a total estimated cost of $250 million to $260 million (including AFDC). In November 2006, PGE executed an agreement to acquire 76 wind turbines for the project’s first phase and in February 2007 entered into a contract for the balance of plant construction. The Company will file a rate application with the OPUC on March 2, 2007 seeking an approximate $13 million increase in annual revenue requirements for full recovery of all costs related to the first phase of the Biglow Canyon Wind Farm.

Hydro Relicensing

The 30-year license for PGE's Clackamas River Hydroelectric Project expired on August 31, 2006. The Company filed an application with the FERC in 2004 to relicense the project. 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 on March 2, 2006 and was submitted to the FERC for review and approval. Pending approval of the new license, the project will operate under annual licenses issued by the FERC. The settlement agreement provides for improved fish and wildlife protection and recreational opportunities at the hydro facilities. It also provides for a collaborative process for the resolution of water temperature issues downstream of the project, which must be settled prior to the issuance of a new license. Although it is not certain when the FERC will issue a new license for the Clackamas River Project, it is expected that the license will be issued by 2009.

Mid-Columbia Hydro Matters

PGE's long-term power purchase contracts with certain public utility districts in the state of Washington expire between 2009 and 2018. In 2001, PGE executed new agreements with Grant County Public Utility District (Grant), operator of the Priest Rapids and Wanapum projects, for periods corresponding to Grant's new license term, to be determined by the FERC. The Priest Rapids agreement became effective in November 2005 and the Wanapum agreement will become effective November 1, 2009. Both contracts, approved by the FERC, extend through the life of Grant's new license, which is expected to be approximately 50 years. Under the terms of the agreements, Grant will annually determine the output required for its purposes, while PGE will be required to purchase approximately 25% of the output in excess of Grant's requirements over the term of the new license, for which PGE will pay a proportional share of the project's debt service and operating costs. PGE's share in the projects is expected to steadily decline as Grant's needs increase, with the Company's share in the two projects reduced from the current 259 MW to an estimated 149 MW in 2010. Also under the agreements, PGE is to purchase an additional 50 MWa annually during the period 2006-2011.

For further information regarding PGE's power purchase contracts from mid-Columbia projects, see Note 9, Commitments and Guarantee, in the Notes to Financial Statements.

Trojan Investment Recovery

In 1993, following the closure of the Trojan Nuclear Plant as part of its least cost planning process, PGE sought full recovery of, and a rate of return on, its Trojan plant costs, including decommissioning, in a general rate case filing with the OPUC. In 1995, the OPUC issued a general rate order which granted the Company recovery of, and a rate of return on, 87% of its remaining investment in Trojan plant costs, and full recovery of its estimated decommissioning costs through 2011.

Numerous challenges, appeals and reviews were subsequently filed in the Marion County 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 Oregon Court of Appeals issued an opinion in 1998, stating that the OPUC does not have the authority to allow PGE to recover a return on the Trojan investment, but upholding the OPUC's authorization of PGE's recovery of the Trojan investment and ordering remand of the case to the OPUC. PGE, the OPUC, and the Utility Reform Project each requested the Oregon Supreme Court to conduct a review of the Court of Appeals decision. On November 19, 2002, the Oregon Supreme Court dismissed the petitions for review. As a result, the 1998 Oregon Court of Appeals opinion stands and the case has been remanded to the OPUC (1998 Remand).

In 2000, while the petitions for review of the 1998 Court of Appeals decision were pending at the Oregon Supreme Court, PGE, the Citizens Utility Board, 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 settlement agreements, approved by the OPUC in September 2000, 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 Utility Reform Project (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 URP's challenges, and approving the accounting and ratemaking elements of the 2000 settlement. URP appealed the 2002 Order to the Marion County Circuit Court and on November 7, 2003, the Marion County Circuit Court issued an opinion remanding the case to the OPUC for action to reduce rates or order refunds (2003 Remand). The opinion does not specify the amount or timeframe of any reductions or refunds. PGE and the OPUC have appealed the 2003 Remand to the Oregon Court of Appeals.

The OPUC combined the 1998 Remand and the 2003 Remand into one proceeding and is considering the matter in phases. The first phase addresses what rates would have been if the OPUC had interpreted the law to prohibit a return on the Trojan investment. The subsequent phases will address reconciling the results of the first phase with actual rates, and adjusting rates to the extent necessary. A decision is pending in the first phase of the proceeding. On November 15, 2006, PGE filed a motion with the OPUC to Consolidate Phases and Re-Open the Record. A ruling on the motion is pending.

On February 16, 2007, the Oregon Court of Appeals declined to reverse or abate the 2003 Remand and ordered the parties to file revised briefs with the Court of Appeals.

In a separate legal proceeding, two class action suits were filed in Marion County Circuit Court against PGE on January 17, 2003 on behalf of two classes of electric service customers. One 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 other 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 for the Current Class and $70 million for the Former Class, as a result of the inclusion of a return on investment of Trojan in the rates PGE charges 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 these class action proceedings until the OPUC responds to the 2003 Remand (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 rate reductions or refunds, for any amount of return on the Trojan investment PGE collected in rates for the period from April 1995 through October 2000. The Supreme Court further stated that if the OPUC determines that it can provide a remedy to PGE's customers, then the class action proceedings may become moot in whole or in part, but if the OPUC determines that it cannot provide a remedy, and that decision becomes final, the court system may have a role to play. The Supreme Court also ruled that the plaintiffs retain the right to return to the Marion County Circuit Court for disposition of whatever issues remain unresolved from the remanded OPUC proceedings. 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.

Threatened Litigation - Class Action Lawsuit - On February 14, 2005, PGE received a Notice of Potential Class Action Lawsuit for Damages and Demand to Rectify Damages from counsel representing Frank Gearhart, David Kafoury and Kafoury Brothers, LLC (Potential Plaintiffs), stating that Potential Plaintiffs intend to bring a class action lawsuit against the Company. Potential Plaintiffs allege that for the period from October 1, 2000 to the present, PGE's electricity rates have included unlawful charges for a return on investment in Trojan in an amount in excess of $100 million. Under Oregon law, there is no requirement as to the time the lawsuit must be filed following the 30-day notice period. No action has been filed to date.

Management cannot predict the ultimate outcome of the above matters. However, it believes that the resolution will not have a material adverse impact on the financial condition of the Company, but may have a material impact on the results of operations and cash flows for a future reporting period. No reserves have been established by PGE for any amounts related to this issue.

Nuclear Decommissioning

PGE has completed all radiological decommissioning activities at Trojan and, upon approval of the Nuclear Regulatory Commission (NRC), the plant's operating license was terminated on May 23, 2005. Previously, the steam generators, reactor containment vessel, and other major components were removed and transported to a licensed low level radioactive waste disposal facility in Washington State for permanent storage. Spent nuclear fuel has been stored in the Independent Spent Fuel Storage Installation (ISFSI), an interim dry storage facility that houses the fuel at the plant site until permanent off-site storage is available. Spent fuel storage activities will continue to be subject to NRC regulation until all nuclear fuel is removed from the site, decontamination is completed, and the storage installation is fully decommissioned. The plant's cooling tower was successfully imploded in May 2006 and removal of the plant's containment building is scheduled for 2008. Remaining activities include demolition of the fuel, auxiliary, turbine, and control buildings, and long-term operation and decommissioning of the ISFSI.

PGE has recorded an ARO for Trojan decommissioning of $108 million, measured at estimated fair value, as of December 31, 2006. The ARO estimate assumes that the majority of decommissioning activities were completed at the end of 2006, with remaining costs extending through 2030. The plan anticipates final site restoration activities will begin in 2031 after PGE completes shipment of spent fuel to a USDOE facility. Decommissioning expenditures are estimated at $7 million for 2007, compared to $5 million in 2006.

In 2002, the USDOE formally recommended Yucca Mountain, Nevada as the nation's first long-term geologic (underground) repository for high-level radioactive waste produced in the United States. The proposed location is based on the conclusions of scientific studies of the site, conducted over 20 years, which support a finding of suitability as mandated by the Nuclear Waste Policy Act and various regulations of the NRC, USDOE, and the EPA. The House and Senate approved the site and in 2002, President Bush signed the Yucca Mountain resolution into law. Lawsuits have been filed objecting to the recommendation of Yucca Mountain as a nuclear waster repository. Based upon updated information received from the USDOE regarding the acceptance of spent nuclear fuel from Trojan, PGE has extended its projection for the final shipment of spent fuel from 2023 to 2030. Although it has not yet submitted the required application for an operating license for the repository, the USDOE in July 2006 announced plans to submit a license application to the NRC by June 30, 2008. Further delays may make it difficult for PGE to move its spent nuclear fuel, currently contained in the ISFSI, to permanent underground storage by 2030.

In 2004, the co-owners of Trojan (PGE, Eugene Water & Electric Board, and PacifiCorp) filed a complaint against the USDOE in the U.S. Court of Federal Claims for failure to accept spent nuclear fuel by January 31, 1998, as required by the Standard Form Contract. The plaintiffs paid for permanent disposal services during the period of plant operation (in the total amount of $109 million) and have met all other conditions precedent. Damages sought are in excess of $200 million.

The Energy Policy Act of 1992 provided for the creation of a Decontamination and Decommissioning Fund to finance the cleanup of USDOE gas diffusion plants, with funding provided by both domestic nuclear utilities and the federal government. Contributions are based upon each utility's share of total enrichment services purchased by all domestic utilities prior to enactment of the legislation. PGE's $17 million share of the total funding requirement, based on Trojan's 1.1% usage of total industry enrichment services, was paid in annual installments that began in 1993, with the final payment made in November 2006.

In response to the terrorist attacks of September 11, 2001, the NRC issued interim compensatory security measures for a generalized high-level threat environment at closed nuclear reactors that are in the decommissioning process and at ISFSIs. The new requirements are expected to remain in effect until the NRC determines that the level of threat has diminished, or that other security changes are needed. The NRC issued additional security orders to all operating reactors in 2003 that require operating plants to update their defensive strategies to counter a highly organized attack. It is possible that corresponding similar orders (limited in scope) will eventually be issued to the Trojan ISFSI. Until NRC requirements associated with any new orders are determined, any implementation costs (including their impact on the Trojan decommissioning cost estimate and related funding requirements) are not determinable. However, as any new security requirements are evaluated, any additional costs will be determined and decommissioning cost estimates revised as necessary.

Receivables and Refunds on Wholesale Market Transactions

Receivables - California Wholesale Market

As of December 31, 2006, PGE has net accounts receivable balances totaling approximately $63 million from the California Independent System Operator (ISO) and the California Power Exchange (PX) for wholesale electricity sales made from November 2000 through February 2001. The Company estimates that the majority of this amount was for sales by the ISO and PX to Southern California Edison Company and Pacific Gas & Electric Company.

In March 2001, the PX filed for bankruptcy and in April 2001, Pacific Gas & Electric Company filed a voluntary petition for relief under the provisions of Chapter 11 of the federal Bankruptcy Code. PGE filed a proof of claim in each of the proceedings for all past due amounts. Although both entities have emerged from their bankruptcy proceedings as reorganized debtors, not all claims filed in the proceedings, including those filed by PGE, have been resolved. PGE is continuing to pursue collection of these claims.

Management continues to assess PGE's exposure relative to these receivables. Based upon FERC orders regarding the methodology to be used to calculate refunds related to California wholesale sales (see "Refunds on Wholesale Transactions" below) and the FERC's indication that potential refunds can be offset with accounts receivable related to such sales, PGE has established reserves totaling $40 million related to this receivable amount. The Company is examining numerous options, including legal, regulatory, and other means, to pursue collection of any amounts ultimately not received through the bankruptcy process.

Refunds on Wholesale Transactions

California - On July 25, 2001, the FERC issued an order in the California refund case (Docket No. EL00-95) establishing the scope of and methodology for calculating refunds for wholesale sales transactions made between October 2, 2000 and June 20, 2001 in the spot markets (defined by the FERC as 24 hours or less) operated by the ISO and PX. The order established evidentiary hearings to develop a factual record to provide the basis for the refund calculation. Several additional orders clarifying and further defining the methodology were issued by the FERC and all have been appealed by numerous parties. A hearing was held in 2002 and, on March 26, 2003, the FERC issued an order ruling on various outstanding issues as to how refunds were to be determined. Under this order, PGE estimates its potential liability at between $40 million and $50 million, of which $40 million has been established as a reserve, as discussed above.

Numerous parties, including PGE, filed requests for rehearing of various aspects of the March 26, 2003 order, including the methodology for the pricing of natural gas within the refund formula. On October 16, 2003, the FERC issued an order reaffirming, in large part, the methodology adopted in its March 26, 2003 order. PGE does not agree with the FERC's methodology for determining potential refunds, and, on December 20, 2003 the Company appealed the FERC's October 16, 2003 order to the U.S. Ninth Circuit Court of Appeals; several other parties have also appealed the October 16, 2003 order. On May 12, 2004, the FERC issued an order that denied further requests for rehearing of the October 16, 2003 order. Although there continue to be miscellaneous orders issued in the underlying FERC proceeding, the Ninth Circuit has now begun to hear the numerous appeals. It bifurcated appeals of the existing cases into two phases. The first phase (Phase I) considered arguments regarding jurisdictional issues and the permissible scope of refund liability, both in terms of the time frame for which refunds were ordered and the types of transactions subject to refund. The second phase will consider the issues relating to the refund methodology itself. PGE expects that the Court will establish additional phases as the issues remaining before the FERC become final and are appealed.

As to the jurisdictional issues in Phase I, on September 6, 2005, the Court ruled that the FERC did not have jurisdiction to order municipal utilities and other governmental entities to make refunds for the sales they had made to the ISO and PX that are the subject of the refund proceeding. Requests for rehearing have been filed with regard to this decision.

On August 2, 2006, the Ninth Circuit issued its decision on the remainder of the issues in Phase I (Refund Scope Decision). It upheld the refund effective date of October 2, 2000, but remanded to the FERC the issue of whether it should order refunds for the summer 2000 period pursuant to its authority under Section 309 of the Federal Power Act (FPA) to remedy tariff violations. It also affirmed the FERC's orders on the scope of the refund proceeding, except with regard to the FERC's exclusion of ISO and PX contracts in excess of 24 hours and energy exchanges, and held that transactions in the ISO and PX markets with a duration in excess of 24 hours, as well as energy exchanges, should be included within the scope of the refund case. Although the August 2, 2006 Ninth Circuit decision did not mandate industry-wide refunds for the summer 2000 period, it is possible that, upon remand, the FERC could decide to order such additional refunds. Management cannot predict the outcome of any proceeding or how summer refunds, if they are ordered, might be calculated.

The Ninth Circuit has ordered an extension of the due date for the filing of requests for rehearing of its Refund Scope Decision until April 29, 2007, establishing a mediation process and urging the parties to use the time to assess possibilities of settlement.

Within the refund case, the FERC also issued a series of orders that permit generators serving California to recover certain costs of emission allowances and the costs of fuel incurred to generate power that were in excess of the gas cost component used to establish the refund liability. Under the methodology adopted by the FERC to allocate fuel costs, PGE could be required to pay additional amounts in those hours when it was a net buyer in California spot markets, thus increasing its net refund liability. PGE does not expect a material increase in the Company's potential refund exposure. Partly as a means of limiting its exposure to additional fuel costs and other potential refund liabilities, PGE has opted to become a participant in several settlements filed in the refund case since 2004.

In August 2005, PGE joined in a settlement agreement resolving issues relating to the allocation of the wind-up costs of the PX for both past and future periods. The settlement has been approved by the FERC. Although under the agreement PGE will bear certain additional costs associated with PX obligations to conduct and finalize refund calculations, PGE does not expect those costs to be material to its financial statements.

In several of its underlying refund orders, the FERC has indicated that if marketers, such as PGE, believe that the level of their refund liability has caused them to incur an overall revenue shortfall for their sales to the ISO and PX during the refund period, they will be permitted to file a cost study to prove that they should be permitted to recover additional revenues in excess of the mitigated prices in order to cover their costs. By order issued August 8, 2005, the FERC provided guidelines regarding the manner in which these studies should be conducted and the principles that should govern their preparation. On September 14, 2005, PGE filed a cost recovery study with the FERC. By order issued November 2, 2006, the FERC accepted, subject to PGE making certain additional revisions, a revised cost recovery study that had been filed by PGE in response to an earlier January 26, 2006 order. Pursuant to the November 2, 2006 order, PGE filed a final cost study with the ISO that now reflects an approximate $19.8 million cost offset to its refund obligation. Third parties have challenged PGE's cost recovery filings and made numerous requests that they be rejected in their entirety or that the cost offset be reduced to zero. PGE has filed responses to those challenges.

PGE believes that the FERC erred in certain findings in its orders regarding PGE's cost recovery, and has filed requests for rehearing as to several issues in those orders. Due to the continuing uncertainty related to these matters, PGE has made no adjustment to the $40 million reserve previously established for the Company's potential liability, as described above.

The FERC has indicated that any refunds PGE may be required to pay related to California wholesale sales (plus interest from collection date) can be offset by accounts receivable (plus interest from due date) related to sales in California (see "Receivables - California Wholesale Market" above). In addition, any refunds paid or received by PGE applicable to spot market electricity transactions on and after January 1, 2001 in California may be eligible for inclusion in the calculation of net variable power costs under the Company's power cost adjustment mechanism in effect at that time. This could further mitigate the financial effect of any refunds made or received by the Company.

Challenge of the California Attorney General to Market-Based Rates - On March 20, 2002, the California Attorney General filed a complaint with the FERC against various sellers in the wholesale power market, alleging that the FERC's authorization of market-based rates violated the FPA, and, even if market-based rates were valid under the FPA, that the quarterly transaction reports required to be filed by sellers, including PGE, did not contain the transaction-specific information mandated by the FPA and the FERC. The complaint argued that refunds for amounts charged between market-based rates and cost-based rates should be ordered. The FERC denied the challenge to market-based rates and refused to order refunds, but did require sellers, including PGE, to re-file their quarterly reports to include transaction-specific data. The California Attorney General appealed the FERC's decision to the Ninth Circuit. On September 8, 2004, the Court issued an opinion upholding the FERC's authority to approve market-based tariffs, but also holding that the FERC had the authority to order refunds, if quarterly filing of market-based sales transactions had not been properly made. The Court required the FERC, upon remand, to reconsider whether refunds should be ordered. On October 25, 2004, certain parties filed a petition for rehearing with the Court. On July 31, 2006, the Court summarily denied rehearing, and on December 28, 2006, PGE joined with other parties in filing a petition for certiorari of this decision with the U.S. Supreme Court. On February 5, 2007, the California Attorney General filed in opposition to the petition for certiorari, or, in the alternative if the petition is granted, a cross-petition for certiorari challenging the legality of market-based rate tariffs. In the refund case and in related dockets, including the above challenge to market based rates, the California Attorney General and other California parties have argued that refunds should be ordered retroactively to at least May 1, 2000. Management cannot predict the outcome of these proceedings or whether the FERC will order refunds retroactively to May 1, 2000, and if so, how such refunds would be calculated.

Anomalous Bidding Allegations - By order issued on June 25, 2003, the FERC instituted an investigation into allegations of anomalous bidding activities and practices ("economic withholding") on the part of numerous parties, including PGE. The FERC determined that bids above $250 per MW in the period from May 1, 2000 through October 2, 2000 may have violated tariff provisions of the ISO and the PX. The FERC required companies that bid in excess of $250 per MW to provide information on their bids to the FERC investigation staff. PGE responded to the FERC's inquiries and, on May 12, 2004, the FERC investigation staff issued to PGE a letter terminating the investigation as to the Company without further action. On March 10, 2005, certain California parties filed appeals with the Ninth Circuit, contesting the FERC's conduct of the investigation of the anomalous bidding allegations and the issuance of the dismissal letters.

Pacific Northwest - In the July 25, 2001 order, the FERC also 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 July 2003, numerous parties filed requests for rehearing of the June 2003 FERC order. In November 2003 and February 2004, the FERC issued orders that denied all pending requests for rehearing. Parties have appealed various aspects of these FERC orders. Briefing has been completed and oral argument was held on January 8, 2007. A decision in the case is pending.

Management cannot predict the ultimate outcome of the above matters related to wholesale transactions in California and the Pacific Northwest. However, it believes that the outcome will not have a material adverse impact on the financial condition of the Company, but may have a material impact on the results of operations and cash flows for future reporting periods.

Colstrip Royalty Claim

Western Energy Company (WECO) supplies coal from the Rosebud Mine in Montana under a Coal Supply Agreement and a Transportation Agreement with owners of Colstrip Units 3 and 4, in which PGE has a 20% ownership interest. In 2002 and 2003, WECO received two orders from the Office of

Minerals Revenue Management of the U.S. Department of the Interior which asserted underpayment of royalties and taxes by WECO related to transportation of coal from the mine to Colstrip during the period October 1991 through December 2001. WECO subsequently appealed the two orders to the Minerals Management Service (MMS) of the U.S. Department of the Interior. On March 28, 2005, the appeal by WECO was substantially denied. On April 28, 2005, WECO appealed the decision of the MMS to the Interior Board of Land Appeals of the U.S. Department of the Interior. In late September 2006, WECO received an additional order from the Office of Minerals Revenue Management to report and pay additional royalties for the period January 2002 through December 2004.

In May 2005, WECO received a "Preliminary Assessment Notice" from the Montana Department of Revenue, asserting claims similar to those of the Office of Minerals Revenue Management.

WECO has indicated to the owners of Colstrip Units 3 and 4 that, if WECO is unsuccessful in the above appeal process, it will seek reimbursement of any royalty payments by passing these costs on to the owners. The owners of Colstrip Units 3 & 4 advised WECO that their position would be that these claims are not allowable costs under either the Coal Supply Agreement or the Transportation Agreement.

Management cannot predict the ultimate outcome of the above matters or estimate any potential loss. Based on information currently known to the Company's management, the Company does not expect that this issue will have a material adverse effect on its financial condition, results of operations or cash flows. If WECO is able to pass any of these costs on to the owners, the Company would most likely seek recovery through the ratemaking process.

<u>Environmental Matters</u>

Harborton

A 1997 EPA investigation of a 5.5-mile segment of the Willamette River known as the Portland Harbor revealed significant contamination of sediments within the harbor. The EPA subsequently included the Portland Harbor on the federal National Priority List pursuant to the federal Comprehensive Environmental Response, Compensation, and Liability Act (Superfund).

In December 2000, PGE received from the EPA a "Notice of Potential Liability" regarding the Harborton Substation facility. The notice listed sixty-eight other companies that the EPA believes may be Potentially Responsible Parties (PRPs) with respect to the Portland Harbor Superfund Site.

In February 2002, PGE provided a report on its remedial investigation of the Harborton site to the DEQ. The report concluded that the investigation demonstrated that there is no likely present or past source or pathway for release of hazardous substances to surface water or sediments in the Portland Harbor Superfund Site at or from the site and that the site does not present a high priority threat to present and future public health, safety, welfare, or the environment. The DEQ submitted the report to the EPA and, in a May 18, 2004 letter, the EPA notified the DEQ that, based on the summary information from the DEQ and the stage of the process, the EPA, as of that time, agreed, the Harborton site does not appear to be a current source of contamination to the river.

In December 6, 2005 letter, the DEQ notified PGE that the site is not likely a current source of contamination to the river and that the site is a low priority for further action. Management believes that the Company's contribution to the sediment contamination, if any, from the Harborton Substation site would qualify it as a de minimis PRP.

Sufficient information is currently not available to determine either the total cost of investigation and remediation of the Portland Harbor or the liability of PRPs, including PGE. Management cannot predict the ultimate outcome of this matter or estimate any potential loss. However, it believes this matter will not have a material adverse impact on the Company's financial statements.

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 is also 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 that impacted an approximate two acre area. Elevated levels of contaminants, including metals, pesticides, and polychlorinated biphenyls (PCBs), have been detected at the site. On September 29, 2003, following investigation and site assessment by the EPA, Harbor Oil was included on the federal National Priority List as a federal Superfund site.

PGE received a Special Notice Letter for Remedial Investigation/Feasibility Study 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. The letter started a period for PRPs to participate in negotiations with the EPA to reach a settlement to conduct or finance a Remedial Investigation and Feasibility Study of the Harbor Oil site. PGE, along with other PRPs, is negotiating an Administrative Order of Consent with the EPA to conduct a Remedial Investigation/Feasibility Study.

Sufficient information is currently not available to determine either the total cost of investigation and remediation of the Harbor Oil Site or the liability of PRPs, including PGE. Management cannot predict the ultimate outcome of this matter. However, it believes this matter will not have a material adverse impact on the Company's financial statements.

Air Quality

PGE's operations, principally its fossil-fuel electric generation plants, are subject to the federal Clean Air Act (CAA) and other federal regulatory requirements. State governments also monitor and administer certain portions of the CAA and must set standards that are at least equal to federal standards; Oregon's air quality standards exceed federal standards. Primary pollutants addressed by the CAA that affect PGE are sulfur dioxide (SO_2), nitrogen oxides, carbon monoxide, and particulate matter. PGE manages its emissions by the use of low sulfur fuel, emission controls, emission monitoring, and combustion controls. Required operating permits have been obtained for all thermal generating facilities operated by PGE.

In May 2005, the EPA established the Clean Air Mercury Rule (CAMR), which regulates mercury emissions from the nation's coal-fired electric generating plants. The CAMR includes a federal "cap-and-trade" program (scheduled to begin in 2010), that establishes a cumulative total ("cap") of mercury emissions from all electric generating plants in the United States and assigns to each state a mercury emissions "budget." Individual states had the choice of adopting this model or establishing their own programs.

In October 2006, the Montana Board of Environmental Review adopted final rules on mercury emissions from coal-fired generating units in Montana, including Colstrip, which set strict mercury emission limits by 2010 and established a review process to ensure that such facilities continue to utilize the latest mercury emission control technology. The rules have been submitted to the EPA for review and determination of their compliance with CAMR requirements. PGE has a 20% ownership interest in Colstrip Units 3 and 4.

In December 2006, the Oregon Environmental Quality Commission adopted the Utility Mercury Rule, which limits mercury emissions from new coal-fired power plants in Oregon and requires installation of mercury technology on the Boardman plant and requires the plant to reduce its mercury emission by 90% by July 1, 2012. The rules allow limited mercury allowance trading up to 2018, after which time, no trading will be allowed.

On June 15, 2005, the EPA issued final amendments to its July 1999 Regional Haze Rule. The rule establishes goals to protect visibility and remedy existing impairments resulting from man made pollution. The revised guidelines require determinations of eligibility with respect to SO_2, nitrogen oxides, and particulate emissions. States must develop implementation plans by December 2007.

While it is not yet known what ultimate impact the federal and state regulations on air quality standards will have on future operations, operating costs, or generating capacity of PGE's thermal generating plants, the Company estimates that the capital cost (in 2006 dollars) to meet regional haze rules and install mercury controls at Boardman could be approximately $200 million - $300 million (100% of total project costs). PGE will seek to recover its share of such costs through the ratemaking process.

Boardman and Beaver - The SO_2 emissions allowances awarded under the CAA, along with expected future annual allowances, are sufficient to operate Boardman at a 60% to 67% capacity. PGE has acquired additional emissions allowances, which, in combination with the allowance awards, will allow the operation of Boardman at forecasted capacity for at least the next ten years.

In accordance with federal regional haze rules, the Oregon DEQ is conducting an assessment of emission sources pursuant to a Regional Haze Best Available Retrofit Technology (RH BART) process. Those sources determined to cause, or contribute to, visibility impairment at protected areas will be subject to an RH BART Determination. Several other states are conducting a similar process. The DEQ is working with ten RH BART eligible sources in Oregon, including PGE's Boardman and Beaver generating plants. In January 2006, the Company volunteered to participate in a DEQ pilot project that will analyze information about air emissions from Boardman to determine their effect on visibility in the region, particularly in wilderness and scenic areas. An exemption modeling analysis for identified sources, which began in September 2006, has indicated that the Boardman facility may cause or contribute to visibility impairment in several protected areas.

Colstrip Plant - PGE has a 20% ownership interest in Colstrip Units 3 and 4, which are operated by PPL Montana, LLC (PPL Montana). PPL Montana and the EPA are discussing possible emission control and monitoring requirements involving all Colstrip units to address certain issues that have arisen since late 2003, including those related to the CAA. Current emissions allowances are sufficient to operate Colstrip, which utilizes wet scrubbers.

In December 2003, PPL Montana, LLC (PPL Montana), the operator of the Colstrip coal fired generating plant, received an Administrative Compliance Order (ACO) from the EPA pursuant to the CAA. The EPA alleges that since 1980, Colstrip Units 3 and 4, have been in violation of the clean air permit issued under the CAA. The permit requires Colstrip Units 3 and 4 to submit, for review and approval by the EPA, an analysis and proposal for reducing NO_x emissions to address visibility concerns if and when the EPA establishes requirements for such emissions. The EPA asserts that regulations it established in 1980 triggered the requirement. PPL Montana has been in settlement negotiations with the EPA and the Northern Cheyenne Tribe to resolve this matter. PPL Montana and the other Colstrip owners, as well as the Northern Cheyenne Tribe, have executed a consent decree that is now awaiting signature by the EPA. Following execution by all parties, the agreement is expected to be entered in the United States District Court for the District of Montana and the EPA's action would then be discontinued. The agreement calls for installation of low nitrogen oxide equipment on Colstrip Units 3 and 4, payment of a non-material penalty and financing of an energy efficiency project. The Company anticipates that its share of the capital improvements and other costs will total approximately $5.8 million, which it will seek to recover through the ratemaking process.

Stock-Based Compensation

On July 13, 2006, PGE granted restricted stock units (Stock Units) with time-based vesting conditions (Restricted Stock Units) and performance-based vesting conditions (Performance Stock Units) to non-employee members of the Company's Board of Directors, officers, and certain key employees. Each Stock Unit represents the right to receive one share of the Company's common stock at a future date, subject to applicable vesting requirements. The grants were made pursuant to the terms of the Portland General Electric Company 2006 Stock Incentive Plan, the purpose of which is to provide common stock-based incentives which will attract, retain, and motivate directors, officers, and key employees of the Company.

Effective July 1, 2006, PGE adopted SFAS No. 123R, Share-Based Payment, which requires that the compensation cost related to share-based payment transactions be recognized in financial statements at fair value, based on the market price of the underlying common stock on the date of grant, and charged to expense over the vesting period based on the number of shares expected to vest. The Company adopted SFAS No. 123R using the Modified Prospective Application method, which applies to new awards and to awards modified, repurchased, or cancelled as of the beginning of the period in which SFAS No. 123R is adopted. For the year ended December 31, 2006, PGE recorded $1 million of stock-based compensation. Based upon the attainment of performance goals that would allow the vesting of 100% of awarded Performance Stock Units, and utilizing an estimated forfeiture rate of 3%, unrecognized compensation expense related to unvested Stock Units was $3.7 million at December 31, 2006, of which $1.6 million, $1.4 million, and $0.7 million is expected to be expensed in 2007, 2008, and 2009, respectively.

Restricted Stock Units will be granted to non-employee directors, as part of their annual compensation arrangement, on or about July 1 each year. It is also anticipated that Stock Unit grants will be made to PGE officers and key employees in future years, resulting in "overlapping" vesting periods and an increase in recorded compensation expense and additional common stock equity.

For additional information, see Note 5, Stock-Based Compensation, in the Notes to Financial Statements.

New Accounting Standards

FASB Interpretation No. 48 (FIN 48), Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109, was issued in July 2006 and is effective for annual reporting periods beginning after December 15, 2006. FIN 48 seeks to reduce the diversity in practice associated with certain aspects of the recognition and measurement requirements related to accounting for income taxes. It requires that a tax position meet a "more-likely-than-not threshold" for the benefit of an uncertain tax position to be recognized in the financial statements. FIN 48 requires recognition in the financial statements of the best estimate of the effects of a tax position only if that position is more likely than not of being sustained on audit by the appropriate taxing authorities, based solely on the technical merits of the position. Based upon an assessment of the application of FIN 48 with respect to PGE's income taxes, the adoption of FIN 48 is not expected to have a material effect on the financial statements of the Company.

SFAS No. 157, Fair Value Measurements, was issued in September 2006 and is effective for fiscal years beginning after November 15, 2007. SFAS No. 157 provides enhanced guidance for the use of fair value to measure assets and liabilities. It also requires expanded disclosure regarding the extent to which fair value is used for such measurements, information used to measure fair value, and the effect of fair value measurements on earnings. Provisions of SFAS No. 157 apply whenever other accounting standards require (or permit) assets or liabilities to be measured at fair value, but does not expand the use of fair value in any new circumstances. PGE is evaluating the application of SFAS No. 157 with respect to its assets and liabilities.

SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities, was issued in February 2007 and is effective for fiscal years beginning after November 15, 2007. SFAS No. 159 provides entities the option to report most financial assets and liabilities at fair value, with changes in fair value recorded in earnings. It also establishes presentation and disclosure requirements designed to facilitate comparisons between companies that choose different measurement attributes for similar types of assets and liabilities. PGE is evaluating the application of SFAS No. 159 with respect to its assets and liabilities.

Information Regarding Forward-Looking Statements

This report contains statements that are forward-looking within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements are statements of expectations, beliefs, plans, objectives, assumptions or future events or performance. Words or phrases such as "anticipates," "believes," "should," "estimates," "expects," "intends," "plans," "predicts," "projects," "will likely result," "will continue," or similar expressions identify forward-looking statements.

Forward-looking statements are not guarantees of future performance and involve risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed. PGE's expectations, beliefs and projections are expressed in good faith and are believed by PGE to have a reasonable basis including, without limitation, management's examination of historical operating trends, data contained in records and other data available from third parties, but there can be no assurance that PGE's expectations, beliefs or projections will be achieved or accomplished.

In addition to other factors and matters discussed elsewhere in this report, some important 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 investigations and actions, including those of the FERC and OPUC with respect to allowed rates of return, financings, electricity pricing and rate structures, acquisition and disposal of assets and facilities, operation and construction of plant facilities, recovery of net variable power costs and other capital investments, and present or prospective wholesale and retail competition;

- matters regarding the effects of Oregon law related to utility rate treatment of income taxes (SB 408), resulting in potential earnings volatility and adverse effects on operating results;

- events related to City of Portland, Oregon investigations with regard to rates charged by the Company, and any attempt by the City of Portland to set rates for PGE customers located within the City of Portland;

- changes in weather, hydroelectric, and energy market conditions, which could affect PGE's ability and cost to procure adequate supplies of fuel or purchased power to serve its customers;

- wholesale energy prices (including the effect of FERC price controls) and their effect on the availability and price of wholesale power purchases and sales in the western United States;

- the completion of major generating plants on schedule;

- the effectiveness of PGE's risk management policies and procedures and the creditworthiness of customers and counterparties;

- operational factors affecting PGE's power generation facilities;

- increasing national and international concerns regarding global warming and proposed regulations that could result in requirements for additional pollution control equipment or significant emissions fees or taxes, particularly with respect to coal-fired generation facilities, to mitigate carbon dioxide and other gas emissions, including regional haze and mercury emissions affecting the Company's thermal generating plants;

- changes in, and compliance with, environmental and endangered species laws and policies;

- financial or regulatory accounting principles or policies imposed by governing bodies;

- residential, commercial, and industrial growth and demographic patterns in PGE's service territory;

- the loss of any significant customer, or changes in the business of a major customer, that may result in changes in demand for PGE services;

- the ability of PGE to access the capital markets to support requirements for working capital, construction costs, and the repayment of maturing debt;

- capital market conditions, including interest rate fluctuations and capital availability;

- changes in PGE's credit ratings, which could have an impact on the availability and cost of capital;

- new federal, state, and local laws that could have adverse effects on operating results;

- legal and regulatory proceedings and issues;

- employee workforce factors, including strikes, work stoppages, and the loss of key executives;

- general political, economic, and financial market conditions; and

- terrorist activities.

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.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

PGE is exposed to various forms of market risk (including changes in commodity prices, foreign currency exchange rates, and interest rates), as well as to credit risk. These changes may affect the Company's future financial results, as discussed below.

Commodity Price Risk

PGE's primary business is to provide electricity to its retail customers. The Company uses purchased power contracts to supplement its thermal and hydroelectric generation to respond to fluctuations in the demand for electricity and variability in generating plant operations. In meeting these needs, PGE is exposed to market risk arising from the need to purchase power and to purchase fuel for its natural gas and coal fired generating units. 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.

Gains and losses from non-trading instruments that reduce commodity price risks are recognized when settled in Purchased Power and Fuel expense, or in wholesale revenue. Valuation of these financial instruments reflects management's best estimates of market prices, including closing New York Mercantile Exchange and over-the-counter quotations, time value of money, and volatility factors underlying the commitments.

PGE actively manages its risk to ensure compliance with its risk management policies. The Company monitors open commodity positions in its energy portfolio 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 in the non-trading portfolio. 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 non-trading portfolio in 2006 were $5.7 million, $9.9 million, and $3.3 million, respectively, and in 2005 were $3.8 million, $9.7 million, and $1.8 million, respectively.

In 2006, PGE adopted a "medium term" power cost strategy to better respond to changing energy market conditions. By extending the period in which the Company may take positions in power markets from 24 months to up to five years, PGE expects to reduce price volatility for its customers during the next three- to five-year period. Accordingly, PGE has amended its risk limits for the projected impact of the medium term strategy on the Company's net open position.

PGE's non-trading activities are subject to regulation. 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 under SFAS No. 71. As contracts are settled, these deferrals reverse. In PGE's non-trading value at risk methodology, no amounts are included for potential deferrals under SFAS No. 71.

Foreign Currency Exchange Rate Risk

PGE faces exposure to foreign currency risk associated with natural gas forward and swap contracts denominated in Canadian dollars in its non-trading 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.

At December 31, 2006, a 10% change in the value of the Canadian dollar would result in an immaterial change in pre-tax income 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 $400 million five-year unsecured revolving credit facility. 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. At December 31, 2006, PGE had $81 million short-term debt outstanding through the issuance of 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 will consider such instruments in the future as necessary.

The total fair value and carrying amounts (including current maturities) of PGE's long-term debt are as follows (in millions):

		Carrying Amounts by Maturity Date						
	Total Fair Value	Total	2007	2008	2009	2010	2011	After 2011
First Mortgage Bonds	$ 674	$ 645	$ 50	$ -	$ -	$ -	$ -	$ 595
Pollution Control Revenue Bonds (*)	197	194	-	-	-	37	-	157
Other	175	164	16	-	-	149	-	(1)
Total	$ 1,046	$ 1,003	$ 66	$ -	$ -	$ 186	$ -	$ 751

(*) Interest rates on $142 million of Pollution Control Revenue Bonds are fixed until 2009. In 2009, pursuant to terms of the bond agreements, PGE will re-market the bonds and re-set the interest rate and maturity date up to the year 2033. A 1% increase in the current interest rates would result in an approximate $1.4 million annual increase in interest expense.

For detail of debt by category, see Note 7, Credit Facility and Debt, in the Notes to Financial Statements.

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 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 following table presents PGE's credit exposure for commodity non-trading activities and their subsequent maturity as of December 31, 2006. The table reflects credit risk included in accounts receivable and price risk management assets, offset by related accounts payable and price risk management liabilities (dollars in millions):

				Maturity of Credit Risk Exposure					
Rating	**Credit Risk Before Collateral**	**Percentage of Total Exposure**	**Credit Collateral**	**2007**	**2008**	**2009**	**2010**	**2011**	**After 2011**
Investment Grade	$ 58	95%	$ 24	$ 18	$ 15	$ 13	$ 2	$ 2	$ 8
Non-Investment Grade	1	2%	-	1	-	-	-	-	-
Internally Rated - Investment Grade	1	2%	-	1	-	-	-	-	-
Internally Rated - Non-Investment Grade	1	1%	-	1	-	-	-	-	-
Total	$ 61	100%	$ 24	$ 21	$ 15	$ 13	$ 2	$ 2	$ 8

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. Non-Investment Grade includes those counterparties with below investment grade credit ratings on senior unsecured debt. For non-rated counterparties, PGE performs credit analysis to determine an internal credit rating that approximates investment or non-investment grade. Included in this analysis is a review of counterparty financial statements, specific business environment, access to capital, and indicators from debt and capital markets. 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 non-trading market risk exposures 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 2018. Management believes that circumstances that could result in the nonperformance by these counterparties are remote.

The large number and diversified base of residential, commercial, and industrial customers, combined with the Company's ability to discontinue service, contribute to reduced credit risk with respect to trade accounts receivable from retail electricity sales. Estimated provisions for uncollectible accounts receivable related to retail electricity sales are provided for such risk. At December 31, 2006, the likelihood of significant losses associated with credit risk in trade accounts receivable is remote.

Risk Management Committee

PGE has a Risk Management Committee (RMC) which is responsible for providing oversight of the adequacy and effectiveness of the 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.

For further information on price risk management activities, see Note 10, Price Risk Management, in the Notes to Financial Statements.

Item 8. Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders 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, 2006 and 2005, and the related consolidated statements of income, retained earnings, comprehensive income, and cash flow for each of the three years in the period ended December 31, 2006. Our audits also included the financial statement schedule listed in Item 15(a). These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule 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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Portland General Electric Company and subsidiaries as of December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Notes 1 and 2 to the consolidated financial statements, on December 31, 2006, the Company changed its method of accounting for defined benefit and other postretirement plans upon the adoption of Statement of Financial Accounting Standards No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2006, based on the criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 1, 2007 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Deloitte & Touche LLP
Portland, Oregon
March 1, 2007

Portland General Electric Company and Subsidiaries
Consolidated Statements of Income

For the Years Ended December 31	2006	2005	2004
	(In Millions, except per share amounts)		
Operating Revenues	$ 1,520	$ 1,446	$ 1,454
Operating Expenses			
Purchased power and fuel	763	671	667
Production and distribution	140	128	127
Administrative and other	164	168	148
Depreciation and amortization	219	233	233
Taxes other than income taxes	75	74	72
Income taxes	38	46	57
	1,399	1,320	1,304
Net Operating Income	121	126	150
Other Income (Deductions)			
Allowance for equity funds used during construction	16	8	6
Miscellaneous	1	(5)	2
Income taxes	2	3	3
	19	6	11
Interest Charges			
Interest on long-term debt and other	69	68	69
Net Income	$ 71	$ 64	$ 92
Common Stock:			
Weighted-average shares outstanding (thousands), Basic	62,501	62,500	62,500
Weighted-average shares outstanding (thousands), Diluted	62,505	62,500	62,500
Earnings per share, Basic and Diluted	$ 1.14	$ 1.02	$ 1.48
Dividends declared per share	$ 0.675	$ *	$ *

* Not meaningful as the Company was a wholly-owned subsidiary of Enron.

The accompanying notes are an integral part of these consolidated financial statements.

Portland General Electric Company and Subsidiaries
Consolidated Statements of Retained Earnings

For the Years Ended December 31	2006	2005	2004
		(In Millions)	
Balance at Beginning of Year	$ 558	$ 644	$ 552
Net Income	71	64	92
	629	708	644
Dividends Declared - Common Stock	42	150	-
Balance at End of Year	$ 587	$ 558	$ 644

The accompanying notes are an integral part of these consolidated financial statements.

Portland General Electric Company and Subsidiaries
Consolidated Statements of Comprehensive Income

For the Years Ended December 31	2006	2005	2004
		(In Millions)	
Accumulated other comprehensive income (loss) - Beginning of Year			
Unrealized gain (loss) on derivatives classified as cash flow hedges	$ -	$ (2)	$ 2
Minimum pension liability adjustment	(3)	(4)	(4)
Total	$ (3)	$ (6)	$ (2)
Net Income	$ 71	$ 64	$ 92
Other comprehensive income, net of tax:			
Unrealized gains (losses) on derivatives classified as cash flow hedges:			
Other unrealized holding gains arising during the period, net of related taxes of $16 in 2006, $(18) in 2005, and $(8) in 2004	(26)	28	12
Reclassification adjustment for contract settlements included in net income, net of related taxes of $7 in 2006, $(3) in 2005, and $4 in 2004	(11)	4	(6)
Reclassification adjustment in net income due to discontinuance of cash flow hedges, net of related taxes of $1 in 2005	-	(1)	-
Reclassification of unrealized gains (losses) to SFAS No. 71 regulatory (liability) asset, net of related taxes of $(24) in 2006, $19 in 2005, and $6 in 2004	37	(29)	(10)
Total - Unrealized gains (losses) on derivatives classified as cash flow hedges	-	2	(4)
Minimum pension liability adjustment	1	1	-
Total Other comprehensive income (loss)	1	3	(4)
Comprehensive income	$ 72	$ 67	$ 88
Accumulated other comprehensive income (loss) - End of Year			
Unrealized gain (loss) on derivatives classified as cash flow hedges	$ -	$ -	$ (2)
Minimum pension liability adjustment	(2)	(3)	(4)
Pension and other postretirement plans' funded position, net of related taxes of $35	(58)	-	-
Reclassification of defined benefit pension plan and other benefits to SFAS No. 71 regulatory asset, net of related taxes of $(33)	54	-	-
Total	$ (6)	$ (3)	$ (6)

The accompanying notes are an integral part of these consolidated financial statements.

Portland General Electric Company and Subsidiaries
Consolidated Balance Sheets

At December 31	2006	2005
Assets	(In Millions)	
Electric Utility Plant - Original Cost		
Utility plant (includes construction work in progress of $412 and $177)	$ 4,582	$ 4,224
Accumulated depreciation	(1,864)	(1,788)
	2,718	2,436
Other Property and Investments		
Nuclear decommissioning trust, at market value	42	31
Non-qualified benefit plan trust	70	69
Miscellaneous	26	34
	138	134
Current Assets		
Cash and cash equivalents	12	122
Accounts and notes receivable (less allowance for uncollectible accounts of $45 and $50)	177	203
Unbilled revenues	88	78
Assets from price risk management activities	93	259
Inventories, at average cost	64	54
Margin deposits	46	-
Prepayments and other	25	24
Deferred income taxes	22	-
	527	740
Deferred Charges		
Regulatory assets	351	217
Miscellaneous	33	111
	384	328
	$ 3,767	$ 3,638
Capitalization and Liabilities		
Capitalization		
Common stock equity:		
Common stock, no par value, 80,000,000 shares authorized; 62,504,767 and 62,500,000 shares outstanding at December 31, 2006 and 2005	$ 643	$ 642
Retained earnings	587	558
Accumulated other comprehensive income (loss):		
Pension and other postretirement plans	(6)	(3)
Long-term debt	937	879
	2,161	2,076
Commitments and Contingencies (see Notes)		
Current Liabilities		
Long-term debt due within one year	66	11
Short-term borrowings	81	-
Accounts payable and other accruals	212	260
Liabilities from price risk management activities	155	129
Customer deposits	5	53
Accrued interest	15	17
Accrued taxes	14	42
Dividends payable	14	-
Deferred income taxes	-	51
	562	563
Other		
Deferred income taxes	251	218
Deferred investment tax credits	7	10
Trojan asset retirement obligation	108	107
Accumulated asset retirement obligation	26	27
Regulatory liabilities:		
Accumulated asset retirement removal costs	411	349
Other	112	175
Non-qualified benefit plan liabilities	84	79
Miscellaneous	45	34
	1,044	999
	$ 3,767	$ 3,638

The accompanying notes are an integral part of these consolidated financial statements

Portland General Electric Company and Subsidiaries
Consolidated Statements of Cash Flow

For the Years Ended December 31	2006	2005	2004
		(In Millions)	
Cash Flows From Operating Activities:			
Reconciliation of net income to net cash provided by operating activities			
Net income	$ 71	$ 64	$ 92
Non-cash items included in net income:			
Depreciation and amortization	219	233	233
Deferred income taxes	(38)	(53)	(13)
Net assets from price risk management activities	132	(40)	(7)
Power cost adjustment	-	18	40
Other non-cash income and expenses (net)	26	8	(6)
Regulatory deferrals - price risk management activities	(132)	36	22
Changes in working capital:			
Net margin deposit activity	(94)	35	13
(Increase) Decrease in receivables	17	(29)	43
Increase (Decrease) in payables	(88)	82	(61)
Other working capital items - net	(11)	4	(22)
Other - net	4	14	6
Net Cash Provided by Operating Activities	106	372	340
Cash Flows From Investing Activities:			
Capital expenditures	(371)	(255)	(194)
Proceeds from sale of assets	6	-	-
Purchases of nuclear decommissioning trust securities	(37)	(34)	(31)
Sales of nuclear decommissioning trust securities	21	21	32
Other - net	1	(4)	9
Net Cash Used in Investing Activities	(380)	(272)	(184)
Cash Flows From Financing Activities:			
Repayment of long-term debt	(162)	(32)	(61)
Issuance of long-term debt	275	-	-
Issuance of short-term debt	81	-	-
Debt issue costs	(2)	-	-
Dividends paid	(28)	(150)	-
Net Cash Provided by (Used in) Financing Activities	164	(182)	(61)
Increase (Decrease) in Cash and Cash Equivalents	(110)	(82)	95
Cash and Cash Equivalents, Beginning of Period	122	204	109
Cash and Cash Equivalents, End of Period	$ 12	$ 122	$ 204
Supplemental disclosures of cash flow information			
Cash paid during the period:			
Interest, net of amounts capitalized	$ 55	$ 58	$ 62
Income taxes	101	88	83
Non-cash investing and operating activities:			
Accrued capital additions	20	9	9

The accompanying notes are an integral part of these consolidated financial statements.

Portland General Electric Company and Subsidiaries
Notes to Consolidated Financial Statements

Nature of Operations

Portland General Electric Company (PGE, or the Company) is a single, integrated electric utility engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the State of Oregon. The Company also sells wholesale electric energy to utilities, brokers, and power marketers located throughout the western United States. 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 service area is located entirely within Oregon and 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. At the end of 2006, PGE's service area population was approximately 1.6 million, comprising about 43% of the state's population. The Company served approximately 793,000 retail customers at December 31, 2006.

On July 2, 1997, Portland General Corporation, the former parent of PGE, merged with Enron Corp., with Enron Corp. continuing in existence as the surviving corporation. On December 2, 2001, Enron Corp., along with certain of its subsidiaries, filed to initiate bankruptcy proceedings under Chapter 11 of the federal Bankruptcy Code. PGE was not included in the filing.

In accordance with Enron's Chapter 11 Plan, on April 3, 2006 PGE issued 62.5 million shares (of 80 million, no par value, shares authorized) of new PGE common stock. Approximately 27 million shares of the new PGE common stock were initially issued to the Debtors' creditors holding allowed claims, and approximately 35.5 million shares were issued to a Disputed Claims Reserve (DCR), where the shares will be held to be released over time to the Debtors' creditors holding allowed claims, in accordance with the Chapter 11 Plan. At December 31, 2006, approximately 32.5 million shares were held in the DCR. The 42.8 million shares of PGE common stock previously held by Enron were cancelled. Following issuance of the new PGE common stock, PGE ceased to be a subsidiary of Enron. The new PGE common stock is listed on the New York Stock Exchange under the ticker symbol POR.

Note 1 - Summary of Significant Accounting Policies

Consolidation Principles

The consolidated financial statements include the accounts of PGE and its majority-owned subsidiaries, including variable interest entities when it is the primary beneficiary with a controlling financial interest. The Company's ownership share of direct expenses and plant costs related to jointly owned generating plants are also included in the consolidated financial statements. Intercompany balances and transactions have been eliminated.

Basis of Accounting

PGE and its subsidiaries' financial statements conform to accounting principles generally accepted in the United States. In addition, PGE's accounting policies are in accordance with the requirements and the rate making practices of regulatory authorities having jurisdiction.

Use of Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at 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.

Contingencies

Contingencies are evaluated based on Statement of Financial Accounting Standards (SFAS) No. 5, Accounting for Contingencies, 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 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 upon realization and are disclosed when material.

Reclassifications

Certain amounts in prior year financial statements have been reclassified for comparative purposes, as discussed below. These reclassifications had no effect on PGE's previously reported consolidated financial position, results of operations, or cash flows.

Pursuant to the April 3, 2006 issuance of new PGE common stock, the December 31, 2005 book value of the $3.75 par value common stock that was cancelled ($160 million) and the December 31, 2005 balance of Other paid-in capital - net ($482 million) have been retroactively combined in the Company's Consolidated Balance Sheets into the single new item "Common stock, no par value" ($642 million).

Prior to 2006, unrealized gains and losses on certain derivative activities that were deferred under SFAS No. 71, Accounting for the Effects of Certain Types of Regulation, to reflect the effects of regulation, were included within "Other working capital items - net" in the Operating Activities section of the Consolidated Statements of Cash Flow. Beginning in 2006, these are reflected in the separate caption "Regulatory deferrals - price risk management activities", with 2004 and 2005 amounts reclassified for comparative purposes.

Prior to 2006, amounts representing "Allowance for equity funds used during construction" were included within "Miscellaneous" under "Other Income (Deductions)" on the Consolidated Statements of Income. Beginning in 2006, such amounts are reflected in a separate caption, with 2004 and 2005 amounts reclassified for comparative purposes.

Revenues

Retail revenues are recognized when monthly billings are made for energy sold to customers and delivered to those customers that purchase their energy from Energy Service Suppliers (ESSs); such revenues are recorded "net" of any taxes imposed on individual revenue-producing transactions. In addition, estimated unbilled revenues are accrued for services provided to retail customers from the meter read date to month-end. Unbilled revenues are calculated based upon each month's actual net system load, the number of days from meter-reading date to month-end, and current retail customer prices. Estimated provisions for uncollectible accounts receivable related to retail electricity 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 probable collection of customer accounts, aging of accounts receivable, bad debt write-offs, actual customer billings, and other factors.

Wholesale revenues are recognized as energy is delivered to the Company's wholesale customers (primarily utilities and energy marketers) during the month. 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.

In certain situations, PGE defers the recognition of revenues until the period in which the related costs are incurred, in accordance with the provisions of SFAS No. 71.

Purchased Power

In addition to power purchases and certain price risk management activities (described under "Price Risk Management" in this Note), certain other activities are reflected in Purchased Power and Fuel expense. These consist of: 1) amounts related to certain power cost adjustments and deferrals; 2) amounts recorded under PGE's long-term power exchange contracts that help meet seasonal peaking requirements (for further information, see "Purchased Power" in Note 9, Commitments and Guarantees); and, 3) provisions related to wholesale accounts receivable and unsettled positions (described under "Revenues" in this Note).

Price Risk Management

PGE engages in price risk management activities in its electric business, utilizing derivative instruments such as electricity forward, swap, and option contracts and natural gas forward, swap, option, and futures contracts. Under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (as amended), derivative instruments are recorded on the Consolidated Balance Sheets as Assets and Liabilities from Price Risk Management Activities measured at fair value, unless they qualify for the normal purchases and normal sales exception, with changes in fair value recognized currently in earnings unless hedge accounting applies.

Non-Trading

Certain non-trading electricity forward contracts that are 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 under SFAS No. 133, as amended by SFAS No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities. Other non-trading activities consist of certain electricity forwards and natural gas forwards and swaps that qualify as cash flow hedges of forecasted transactions, and electricity options, certain electricity forwards, certain natural gas swaps and forward contracts for acquiring Canadian dollars that are classified as non-hedges. Such activities are utilized to protect against variability in expected future cash flows due to associated price risk and to minimize net power costs for retail customers.

The Public Utility Commission of Oregon (OPUC), which regulates PGE's retail electricity business, recognizes non-trading 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 (OCI) and contracts designated as non-hedges are recorded net in Purchased Power and Fuel expense on the Statement 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 regulation under SFAS No. 71.

Prior to December 2006, PGE recorded a regulatory asset or regulatory liability under SFAS No. 71 to offset unrealized gains and losses on certain non-trading contracts recorded prior to settlement to the extent that such contracts are included in the Company's Resource Valuation Mechanism (RVM). The regulatory asset or regulatory liability is reflected within Regulatory assets or Regulatory liabilities, respectively, on the Consolidated Balance Sheets. Upon settlement, the regulatory asset or regulatory liability is reversed. In its January 2007 general rate order, the OPUC approved a new Power Cost

Adjustment Mechanism (PCAM) by which PGE can adjust future rates to reflect the difference between each year's forecasted and actual net variable power costs on a settlement basis. As a result, a regulatory asset or regulatory liability is recorded to offset changes in fair value of derivative instruments not included in the RVM. Effective January 17, 2007, a new Annual Power Cost Update Tariff replaced the RVM.

Sales and purchases involving non-trading electricity derivative activities that are physically settled are recorded in Operating Revenues and Purchased Power and Fuel expense, respectively. Non-trading electricity derivative activities that are "booked out" (not physically settled) are recorded on a net basis in Purchased Power and Fuel expense, pursuant to the requirements of Emerging Issues Task Force Issue (EITF) No. 03-11.

Trading

PGE discontinued its energy trading activities for non-retail purposes in early 2005, with remaining transactions settled by December 31, 2005. Realized and unrealized gains and losses associated with such activities are reported on a net basis for all periods presented in accordance with EITF 02-3, Accounting for Contracts Involved in Energy Trading and Risk Management Activities, and are included within Operating Revenues on the Statement of Income.

For further information, see Note 10, Price Risk Management.

Customer Deposits

In the course of its wholesale activities, PGE both receives and deposits performance assurance cash collateral, with required amounts based upon provisions contained in certain wholesale power agreements with counterparties. Amounts deposited with, or received from, counterparties under such agreements are reflected as Margin deposits and Customer deposits, respectively, within the Current Assets and Current Liabilities sections of the Consolidated Balance Sheets. Also included within Current Liabilities are credit deposits received from certain retail and transmission customers.

Capitalization of Property, Plant and Equipment

Additions to utility plant are capitalized at their original cost, consistent with accounting and regulatory guidelines. 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. Plant replacements are capitalized, with minor items charged to expense as incurred. The costs to purchase/develop software applications are capitalized in accordance with American Institute of Certified Public Accountants Statement of Position 98-1, Accounting for the Costs of Computer Software Developed or Obtained for Internal Use. Costs of relicensing the Company's hydroelectric projects are capitalized and amortized over the related license period.

Utility plant at December 31 consists of the following (in millions):

	2006	**2005**
Production	$ 1,414	$ 1,395
Transmission	283	278
Distribution	2,059	1,959
General	242	239
Intangible	172	176
Construction Work in Progress	412	177
Total	$ 4,582	$ 4,224

Depreciation and Amortization of Property, Plant and Equipment

Depreciation is computed using the straight-line method over the estimated average service lives of various classes of plant in service. Classes of plant in service and their estimated service lives (in years) are as follows: Production (33), Transmission (55), Distribution (35), and General (13). Depreciation is 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 4.3% in 2006, 4.4% in 2005, and 4.5% in 2004. Estimated asset retirement removal costs included in depreciation expense were $68 million, $64 million, and $61 million in 2006, 2005, and 2004, 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. The results of the most recent depreciation study, filed in November 2005, were stipulated to in October 2006, and are incorporated into customer rates that became effective on January 17, 2007.

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 asset retirement obligations for assets with AROs and to accumulated asset retirement removal costs for assets without AROs. See Note 12, Asset Retirement Obligations, for further information.

Intangible plant consists primarily of computer software development costs, which are amortized over either five or ten years, and hydro re-licensing costs, which are amortized over the applicable license term. Amortization expense for 2006, 2005, and 2004, was $15 million, $13 million, and $14 million, respectively, and is estimated at $15 million for 2007, $11 million for 2008, 2009, and 2010, and $10 million in 2011. Accumulated amortization was $82 million and $76 million at December 31, 2006 and December 31, 2005, respectively; the increase consists of the net amount of current year amortization expense less accumulated amortization on intangible plant retirements.

Major Maintenance Expenses

Costs of periodic major maintenance inspections and overhauls at the Company's generating plants are charged to operating expenses as incurred. PGE's retail customer rates include the recovery of an annual amount, authorized by the OPUC, for estimated major maintenance expenses incurred at the Company's Coyote Springs combustion turbine generating plant. Differences between amounts authorized in rates and actual expenses incurred are deferred as regulatory assets or regulatory liabilities pursuant to SFAS No. 71.

Allocations and Loadings

PGE utilizes a series of cost distributions and loadings to allocate certain administrative and overhead costs between capital and operating accounts, based primarily on construction activities of the Company.

Allowance for Funds Used During Construction (AFDC)

AFDC represents the pre-tax cost of borrowed funds used for construction purposes and a reasonable rate for equity funds. It is capitalized as part of the cost of plant and is credited to income but does not represent current cash earnings. The average rates used by PGE in 2006, 2005, and 2004 were 9.0%. AFDC from borrowed funds was $8 million in 2006, $4 million in 2005, and $3 million in 2004. AFDC from equity funds was $16 million in 2006, $8 million in 2005, and $6 million in 2004.

Debt Issuance Costs

Underwriting, legal, and other direct costs related to the issuance of debt securities are deferred and amortized to interest expense equitably over the life of the security. Unamortized debt issuance costs at December 31, 2006 and 2005 were $15 million and $16 million, respectively, and are classified within Deferred charges - Miscellaneous on the Consolidated Balance Sheets.

Income Taxes

PGE files consolidated federal and state income tax returns. The Company's policy is to collect for tax liabilities from subsidiaries that generate taxable income and to reimburse subsidiaries for tax benefits utilized in its tax return. Deferred income taxes are provided for temporary differences between financial and income tax reporting. Investment tax credits utilized have been deferred and are amortized to income over the approximate lives of the related properties. See Note 3, Income Taxes, for further information.

PGE's federal taxable income was included in Enron's consolidated federal income tax return from July 2, 1997 through April 2, 2006, with the exception of the period May 8, 2001 through December 23, 2002, during which PGE and its subsidiaries filed their own consolidated tax returns. Upon issuance of new PGE common stock on April 3, 2006, PGE and its subsidiaries are no longer included in Enron's consolidated return. For further information, see Note 17, Related Party Transactions.

Cash and Cash Equivalents

Highly liquid investments with maturities of three months or less at the date of acquisition are classified as cash equivalents.

Non-Qualified Benefit Plan Trust

The non-qualified benefit plan trust is comprised of insurance contracts and investments in money market, bond, and other equity investments. The cash surrender value of insurance contracts is reported as an asset at the end of the reporting period, with changes in such values between reporting periods recognized as income or expense of the period (see "Other Non-Qualified Benefit Plans" in Note 2, Employee Benefits, for further information). The cash surrender value of insurance contracts, the majority of which are held in the trust, was $23 million at December 31, 2006 and $22 million at December 31, 2005. The investments in marketable securities are classified as trading and recorded at fair value on the Consolidated Balance Sheets. Realized and unrealized gains and losses on these investments (determined using average cost) are included in Other Income (Deductions) on the Consolidated Statements of Income. Investments in marketable securities and cash totaled $47 million at both December 31, 2006 and 2005.

Inventories

PGE's inventories are recorded at cost, which includes the purchase price (less discounts), applicable taxes, transportation and handling, etc. The average cost method is utilized to price inventory as fuel is burned at the generating plants and as materials and supplies are issued for operations, maintenance and capital activities. General storeroom operation costs, including procurement, management, and storage, are recorded in the unallocated stores account and distributed equitably as materials and supplies are issued.

Inventories at December 31 are summarized as follows (in millions):

	2006	2005
Coal	$ 20	$ 11
Fuel oil	10	11
Natural gas	3	4
Materials and supplies	28	25
Unallocated stores account	3	3
Total	$ 64	$ 54

Trojan Decommissioning Costs

Trojan decommissioning costs consist of those expenditures related to the decommissioning of the Trojan Nuclear Plant. The present value of estimated future decommissioning expenditures, which is revised periodically, is recorded as an ARO on the Consolidated Balance Sheets, with actual expenditures charged to the ARO account as incurred. See Note 12, Asset Retirement Obligations, and Note 13, Trojan Nuclear Plant, for further information.

Regulatory Assets and Liabilities

PGE is subject to the provisions of SFAS No. 71. Accounting under SFAS No. 71 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.

When the requirements of SFAS No. 71 are met at the date the costs are incurred, or at a later date when evidence supports cost deferral (e.g. an OPUC deferred accounting order), the Company defers certain costs which would otherwise be charged to expense if it is probable that future prices will permit recovery of such costs. In addition, PGE defers certain revenues, gains, or cost reductions which would normally be reflected in income but through the rate making process will ultimately be refunded to customers. Regulatory assets and liabilities are reflected within Deferred Charges and Other on the Consolidated Balance Sheets and are amortized over the period in which they are included in billings to customers. If at some point in the future PGE determines that all or a portion of the utility operations no longer meets the criteria for continued application of SFAS No. 71, PGE could be required to write-off its regulatory assets.

Amounts in the Consolidated Balance Sheets as of December 31 consist of the following (in millions):

	2006	2005
Regulatory assets:		
Trojan decommissioning costs	$ 66	$ 75
Income taxes recoverable	74	80
Debt reacquisition costs	30	21
Conservation investments - secured	-	9
Boardman power cost deferral	6	-
Pension and other postretirement plans	87	-
Regulatory restructuring costs (1)	11	16
Price risk management	62	-
Beaver 8 (1)	7	9
Miscellaneous (2)	8	7
Total	$ 351	$ 217
Regulatory liabilities:		
Asset retirement obligations	$ 27	$ 21
Accumulated asset retirement removal costs	411	349
Price risk management	-	130
Information technology costs (1)	3	3
Trojan ISFSI pollution control tax credits (1)	10	5
Oregon corporation excise tax refund (1)	4	4
Residential Exchange Program (1)	14	-
Oregon Senate Bill 408 (SB 408)(1)	42	-
Miscellaneous (3)	12	12
Total	$ 523	$ 524

(1) A return on the unamortized balance of these items is recorded at PGE's authorized cost of capital (9.083% through 2006 and 8.29% beginning on January 17, 2007).
(2) Of the total miscellaneous unamortized balances, a return is recorded on $3 million at both December 31, 2006 and December 31, 2005 at PGE's authorized cost of capital, as indicated in (1) above.
(3) Of the total miscellaneous unamortized balances, a return is recorded on $6 million at December 31, 2006 and $7 million at December 31, 2005 at PGE's authorized cost of capital, as indicated in (1) above.

Trojan decommissioning costs - PGE's retail prices include recovery of costs to decommission Trojan (see Note 13, Trojan Nuclear Plant, for further information). These amounts represent the estimated fair value of the remaining decommissioning costs to be recovered from customers.

Income taxes recoverable - The amount represents tax benefits previously flowed to customers through rates for temporary differences between book and tax reporting. The balance is reduced as temporary differences reverse and the increase in current tax expense is recovered in customer rates.

Debt reacquisition costs - As authorized by the OPUC, costs related to the reacquisition of debt securities, including unamortized debt issuance costs related to such debt securities, are deferred and amortized to interest expense equitably over the life of the replacement or retired issue as applicable.

Conservation investments - secured - In 1996, $81 million of PGE's energy efficiency investment was designated as Bondable Conservation Investment upon the Company's issuance of 10-year 6.91% conservation bonds collateralized by OPUC-authorized revenues, which funded the debt service obligation. The issuance of such bonds provided PGE immediate recovery of its unamortized energy efficiency program expenditures while providing future savings to customers. These bonds were paid in October 2006.

Boardman power cost deferral - In October 2005, the Boardman Coal Plant (Boardman) was taken out of service for repair of the plant's steam turbine rotor and remained out of service during the first half of 2006 for additional repairs. PGE incurred significant incremental power costs during this period to replace the plant's generation. In November 2005, PGE filed with the OPUC an application to defer for later ratemaking treatment excess power costs associated with Boardman's turbine rotor repair outage. Based upon prior OPUC actions, the stated position of the OPUC staff in the proceeding, and considering both applicable accounting guidance and the impact of SB 408 on any benefit received by the Company, PGE recorded a deferral in the amount of $6 million at December 31, 2006. See Note 18, Subsequent Event, for further information.

Pension and other postretirement plans - On December 31, 2006, PGE adopted SFAS No. 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, which requires that the funded status of pension and other postretirement plans be recognized, with the resulting adjustment recorded to the ending balance of Accumulated OCI on the Consolidated Balance Sheets. Postretirement costs are covered in rates charged to customers through 2006. The OPUC issued an accounting order that authorizes PGE to record a regulatory asset equal to the pretax charge against Accumulated OCI that would otherwise be required by recognition of the pension funded status under SFAS No. 158. As pension expense is recognized in future years, the regulatory asset will be reduced. See Note 2, Employee Benefits, for further information.

Regulatory restructuring costs - The OPUC authorized PGE to defer certain costs related to implementation of Oregon's electric restructuring law. Approximately $24 million is currently being recovered in prices charged to customers, with a remaining balance of $11 million at December 31, 2006. Of the $24 million total implementation costs, $7 million is being recovered over a five-year period that began on January 1, 2003, with a remaining balance of $2 million at December 31, 2006, and $17 million is being recovered over a five-year period that began on January 1, 2004, with a remaining balance of $9 million at December 31, 2006.

Price risk management - SFAS No. 133 requires unrealized gains and losses on derivative instruments that do not qualify for the normal purchase and normal sale exception to be recorded in earnings and other comprehensive income in the current period. To reflect the effects of regulation under SFAS No. 71, timing differences between the recognition of unrealized gains and losses on non-trading derivative instruments and their realization and subsequent recovery in rates are recorded as regulatory assets or regulatory liabilities. Amounts recorded by PGE at December 31, 2006 and 2005 offset the effects of such gains and losses, which are caused by changes in fair values of related energy contracts; recorded amounts are reversed as such contracts are settled. See Note 10, Price Risk Management, for further information.

Beaver 8 - In December 2004, the OPUC issued an Order that adopted a stipulation in which parties agreed that PGE may recover from customers approximately $14 million for costs associated with a 24.7 MW combustion turbine (referred to as Beaver 8) installed at the Company's Beaver generating plant site in 2001. Of this amount, $10 million (plus accrued interest) was deferred for recovery from customers over a five-year period beginning January 1, 2005. The remaining $4 million, representing the current market value of the turbine, remains in plant in service and is depreciated over its useful life.

Asset retirement obligations - SFAS No. 143, Accounting for Asset Retirement Obligations requires the recognition of AROs, measured at estimated fair value, for legal obligations related to dismantlement and restoration costs associated with the retirement of tangible long-lived assets in the period in which the liability is incurred. Pursuant to regulation, AROs of rate-regulated long-lived assets are included as an allowable cost in rates 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 under SFAS No. 71. Asset retirement obligations are included in PGE's rate base for ratemaking purposes.

Accumulated asset retirement removal costs - Asset retirement removal costs that do not qualify as AROs are a component of depreciation expense allowed in customer rates. Accumulated asset retirement removal costs are recorded as a regulatory liability as they are collected in rates, and are reduced by actual removal costs as incurred, in accordance with SFAS No. 143 and SFAS No. 71. This amount is also included as a reduction to PGE's rate base for ratemaking purposes.

Information technology costs - In PGE's 2001 general rate filing, the OPUC approved an estimated amount of capital expenditures related to the Company's Customer Information System (CIS) and Information Technology (IT) activities in the determination of PGE's 2002 revenue requirement. The OPUC's rate order stipulated that PGE's retail customers are to receive a refund if the actual revenue requirement for such costs is less than the estimated revenue requirement. Accordingly, regulatory liabilities of $4 million were recorded from 2003 through 2006 to reflect the difference between actual and estimated revenue requirements related to CIS and IT capital expenditures. Amounts that were deferred are being refunded to customers through 2007.

Trojan ISFSI pollution control tax credits - In December 2004, PGE received final certification from the Oregon Environmental Quality Commission (OEQC) related to $21.1 million in Oregon pollution control tax credits that were generated from PGE's investment in an Independent Spent Fuel Storage Installation (ISFSI) at Trojan. OEQC rules require that the tax credits be spread over a ten-year period, beginning in 2004. The OPUC approved the deferral of the tax credits for future ratemaking treatment. See Note 13, Trojan Nuclear Plant, for further information.

Oregon corporation excise tax refund - Oregon's constitution provides for a Corporation Excise Tax refund when actual state tax revenues exceed those estimated in the state's budget. In 2005, PGE received a tax credit related to the difference between estimated and actual state excise taxes collected during the state's 2003-2005 biennium, with such refund reflected as a credit against the Company's net 2005 tax liability. PGE's share of the state tax credit is being deferred for future refund to customers.

Residential Exchange Program - The Residential Exchange Program, which is administered by the Bonneville Power Administration (BPA), provides access to the benefits of federal power to residential and small farm customers of the region's investor-owned utilities. In 2000, PGE entered into a settlement agreement with the BPA related to the Residential Exchange Program covering the period October 1, 2001 through September 30, 2011. The benefits that PGE receives under the agreement with the BPA are passed through directly to residential and small farm customers in the form of monthly billing credits. The $14 million balance in the regulatory liability represents those benefits received by PGE that have not yet been passed through to eligible customers at December 31, 2006.

SB 408 - This Oregon 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 utilities or their consolidated group. Based on PGE's assessment of rules issued by the OPUC in September 2006, the Company has established a reserve of $42 million (including $2 million in interest) for potential future refunds to customers. Under the law, any refunds to customers would begin after June 1, 2008. For further information, see Note 16, Utility Rate Treatment of Income Taxes.

Recovery/refund period - As of December 31, 2006, the majority of PGE's regulatory assets and liabilities are reflected in customer rates. Based on such rates, PGE estimates that it will collect substantially all of is regulatory assets, and refund its regulatory liabilities (excluding those related to asset retirement obligations and removal costs), within the next 13 years.

New Accounting Standards

SFAS No. 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, was issued in September 2006. SFAS No. 158 requires an employer to recognize in its statement of financial position an asset for a plan's overfunded status or a liability for a plan's underfunded status, measure a plan's assets and its obligations that determine its funded status as of the end of the employer's fiscal year, and recognize changes in the funded status of a defined benefit postretirement plan in the year in which the changes occur. The requirement to recognize the funded status of a benefit plan and the disclosure requirements are effective as of the end of the fiscal year ending after December 15, 2006. PGE adopted SFAS No. 158 at December 31, 2006. For further information, see Note 2, Employee Benefits.

SEC Staff Accounting Bulletin No. 108 (SAB 108), Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements, was issued in September 2006 and is effective for fiscal years ending after November 15, 2006. In addressing the current diversity of practice, SAB 108 provides interpretive guidance on how misstatements should be quantified and requires use of a "dual approach" method when evaluating the materiality of financial statement errors. Such approach requires consideration of the impact of misstatements on both the income statement ("rollover" method) and balance sheet ("iron curtain" method). If such consideration, along with the evaluation of all relevant quantitative and qualitative factors, results in quantifying a misstatement as material, adjustment of financial statements is required. The application of SAB 108 did not have a material effect on the financial statements of the Company.

FASB Interpretation No. 48 (FIN 48), Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109, was issued in July 2006 and is effective for annual reporting periods beginning after December 15, 2006. FIN 48 seeks to reduce the diversity in practice associated with certain aspects of the recognition and measurement requirements related to accounting for income taxes. It requires that a tax position meet a "more-likely-than-not" threshold for the benefit of an uncertain tax position to be recognized in the financial statements. FIN 48 requires recognition in the financial statements of the best estimate of the effects of a tax position only if that position is more likely than not of being sustained on audit by the appropriate taxing authorities, based solely on the technical merits of the position. Based upon an assessment of the application of FIN 48 with respect to PGE's income taxes, the adoption of FIN 48 is not expected to have a material effect on the financial statements of the Company.

SFAS No. 157, Fair Value Measurements, was issued in September 2006 and is effective for fiscal years beginning after November 15, 2007. SFAS No. 157 provides enhanced guidance for the use of fair value to measure assets and liabilities. It also requires expanded disclosure regarding the extent to which fair value is used for such measurements, information used to measure fair value, and the effect of fair value measurements on earnings. Provisions of SFAS No. 157 apply whenever other accounting standards require (or permit) assets or liabilities to be measured at fair value, but does not expand the use of fair value in any new circumstances. PGE is evaluating the application of SFAS No. 157 with respect to its assets and liabilities.

SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities, was issued in February 2007 and is effective for fiscal years beginning after November 15, 2007. SFAS No. 159 provides entities the option to report most financial assets and liabilities at fair value, with changes in fair value recorded in earnings. It also establishes presentation and disclosure requirements designed to facilitate comparisons between companies that choose different measurement attributes for similar types of assets and liabilities. PGE is evaluating the application of SFAS No. 159 with respect to its assets and liabilities.

Note 2 - Employee Benefits

Pension and Other Post-Retirement Plans

Defined Benefit Pension Plan - PGE sponsors a non-contributory defined benefit pension plan, of which substantially all members are current or former PGE employees. The assets of the pension plan are held in a trust. Pension plan calculations include several assumptions which are reviewed annually with PGE's consulting actuaries and trust investment consultants and are updated as appropriate. In 2005, PGE updated the mortality rate assumption used for the pension plan, which resulted in a $14 million increase in the accumulated benefit obligation included in the accompanying table.

In August 2005, PGE transferred $3 million in pension assets from PGE's pension plan to Enron Corp.'s Cash Balance Plan to reflect a net exchange of assets and benefit obligations. These exchanges consolidated benefits for certain individuals who had changed employers and as a result had ceased earning benefits under one plan and began earning benefits under the other plan. The transfer is included in "Divestitures" in the accompanying table.

In December 2005, PGE made a $10 million cash contribution to the pension plan. No contributions were made in 2006 and the Company does not currently expect to make a contribution to the pension plan in 2007. The measurement date for the pension plan is December 31.

Non-Qualified Benefit Plans - The Non-Qualified Benefit Plans in the accompanying table primarily represent obligations for a Supplemental Executive Retirement Plan (SERP). The SERP was closed to new participants in 1997. Investments in a non-qualified benefit plan trust, consisting of trust owned life insurance policies (TOLI) and marketable securities, are intended to be the primary source for financing these plans. Trust assets of $25 million as of December 31, 2006 and $24 million as of December 31, 2005 are shown in the accompanying table for informational purposes only and are not considered segregated and restricted as defined by SFAS No. 158, Employers' Accounting for Defined Benefit Pension and Other Post Retirement Plans. The investments in marketable securities, consisting of money market, bond, and equity mutual funds, are classified as trading and recorded at fair value. Unrealized gains in marketable securities were $2 million for 2006 and $1 million for each of the years 2005 and 2004. In addition, recognized gains on trust assets of $1 million for each of the years 2006, 2005 and 2004 are included in net periodic benefit cost. Realized gains and losses on marketable securities are computed utilizing the average cost of such securities. The measurement date for the non-qualified plans is December 31.

In April 2005, PGE assumed $2 million of non-qualified benefits plan liabilities from Portland General Holdings, Inc. (PGH) as part of a settlement with certain PGH participants. PGE also received $2 million in trust assets to be used for the payment of benefits. These amounts are included in "Assumed plans" in the accompanying table.

Other Benefits - PGE also participates in non-contributory post-retirement health and life insurance plans ("Other Benefits" in the table). Employees are covered under a Defined Dollar Medical Benefit Plan which limits PGE's obligation by establishing a maximum benefit per employee. Contributions made to a voluntary employees' beneficiary association trust are used to fund these plans. Costs of these plans, based upon an actuarial study, are included in rates charged to customers. Post-retirement benefit plan calculations include several assumptions which are reviewed annually with PGE's consulting actuaries and trust investment consultants and updated as appropriate. In 2005, PGE updated the mortality rate assumption used for the post-retirement benefits. The impact of this change on the benefit obligation was not significant.

PGE has also established Health Retirement Accounts (HRAs) for its employees. Contributions are made to trust accounts to provide for claims by retirees for qualified medical costs. The 2004 bargaining unit agreement provides that retired employees may submit claims to the HRA for qualified medical expenses up to 58% of the value of any accumulated sick time at their retirement. The Company also granted a fixed dollar amount for all active non-bargaining employees, which will become available for qualified medical expenses upon their retirement.

No contributions were made to the post-retirement or non-bargaining HRA plans in 2006. Contributions totaling $1 million were made to the bargaining unit HRA in 2006. Contributions to the bargaining unit HRA are expected to be minimal in 2007. No contributions are currently expected to be made to the other post-retirement plans in 2007. The measurement date for the post-retirement plans is December 31.

SFAS No. 158 - SFAS No. 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, requires an employer to recognize in its statement of financial position an asset for a plan's overfunded status or a liability for a plan's underfunded status, measure a plan's assets and its obligations that determine its funded status as of the end of the employer's fiscal year, and recognize changes in the funded status of a defined benefit postretirement plan in the year in which the changes occur.

PGE adopted SFAS No. 158 as of December 31, 2006. Upon adoption, PGE recorded a pre-tax adjustment of $93 million to the ending balance of Accumulated OCI. The adjustment to Accumulated OCI consisted of $82 million of unrecognized actuarial losses, $10 million of unrecognized prior service costs, and $1 million of unrecognized transition obligations. PGE subsequently recorded an offsetting adjustment of $87 million to a regulatory asset under SFAS No. 71. As a result of adopting SFAS No. 158, the Consolidated Balance Sheets changed as follows (in millions):

Balance Sheet Line Item:	Balances prior to adoption of SFAS No. 158	Changes due to SFAS No. 158 adjustment	Balances after adoption of SFAS No. 158
Regulatory assets	$ -	$ 87	$ 87
Deferred charges - Miscellaneous	84	(73)	11
Accounts payable and other accruals	-	2	2
Non-qualified benefit plan liabilities	21	3	24
Other liabilities - miscellaneous	15	15	30
Deferred income taxes	1	2	3
Accumulated OCI (pre-tax)	(3)	(6)	(9)

The following table provides a reconciliation of changes in the Plans' benefit obligations and fair value of assets, a statement of the funded status, and components of net periodic benefit cost (dollars in millions):

	Defined Benefit Pension Plan		Non-Qualified Benefit Plans		Other Benefits	
	2006	2005	2006	2005	2006	2005
Reconciliation of benefit obligation:						
Obligation at January 1	$ 483	$ 450	$ 24	$ 22	$ 59	$ 55
Service cost	13	12	-	-	1	1
Interest cost	27	25	2	1	3	3
Assumed plans	-	-	-	2	-	-
Divestitures	-	(3)	-	-	-	-
Participants' contributions	-	-	-	-	1	1
Actuarial (gain) loss	(6)	18	2	1	(2)	2
Benefit payments	(25)	(19)	(2)	(2)	(4)	(3)
Obligation at December 31	$ 492	$ 483	$ 26	$ 24	$ 58	$ 59
Reconciliation of fair value of plan assets:						
Fair value of plan assets at January 1	$ 469	$ 452	$ 24	$ 22	$ 27	$ 26
Actual return on plan assets	59	29	3	2	3	1
Company contributions	-	10	-	-	1	2
Assumed plans	-	-	-	2	-	-
Participants' contributions	-	-	-	-	1	1
Divestitures	-	(3)	-	-	-	-
Benefit payments	(25)	(19)	(2)	(2)	(4)	(3)
Fair value of plan assets at December 31	$ 503	$ 469	$ 25	$ 24	$ 28	$ 27
Funded status:						
Funded (unfunded) status at December 31	$ 11	$ (14)	$ (1)	$ -	$ (30)	$ (32)
Unrecognized transition liability	*	-	*	-	*	2
Unrecognized prior service cost	*	5	*	-	*	7
Unrecognized loss	*	97	*	3	*	11
Prepaid pension asset (liability)	$ 11	$ 88	$ (1)	$ 3	$ (30)	$ (12)
Accumulated benefit obligation at December 31	$ 436	$ 426	$ 20	$ 21	N/A	N/A
Amounts recognized in the Consolidated Balance Sheets consist of:						
Noncurrent asset	$ 11	$ *	$ -	$ *	$ -	$ *
Current liability	-	*	2	*	-	*
Noncurrent liability	-	*	24	*	30	*
Prepaid benefit cost (liability)	*	88	*	8	*	(12)
Accumulated other comprehensive income	*	-	*	(5)	*	-
Net amount recognized	$ 11	$ 88	$ 26	$ 3	$ 30	$ (12)

(*) With the adoption of SFAS No. 158 at December 31, 2006, certain information is no longer applicable. Similarly, certain information for 2006 was not previously applicable.

	Defined Benefit Pension Plan 2006	Defined Benefit Pension Plan 2005	Non-Qualified Benefit Plans 2006	Non-Qualified Benefit Plans 2005	Other Benefits 2006	Other Benefits 2005
Amounts recognized in accumulated other comprehensive income consist of:						
Net actuarial loss/(gain)	$ 69	$ -	$ 9	$ -	$ 7	$ -
Prior service cost/(credit)	4	-	-	-	6	-
Transition obligation/(asset)	-	-	-	-	1	-
Net amount recognized	$ 73(a)	$ -	$ 9	$ -	$ 14(a)	$ -
Assumptions:						
Discount rate used to calculate benefit obligation	5.75%	5.75%	5.75%	5.75%	5.75%	5.50%
Weighted average rate of increase in future compensation levels	4.44%	4.43%	N/A	N/A	5.07%	5.30%
Long-term rate of return on assets	9.00%	9.00%	N/A	N/A	8.17%	8.62%

(a) Subsequently transferred to Regulatory Assets.

	Defined Benefit Pension Plan			Non-Qualified Benefit Plans			Other Benefits		
	2006	2005	2004	2006	2005	2004	2006	2005	2004
Components of net periodic benefit cost:									
Service cost	$ 13	$ 12	$ 12	$ -	$ -	$ -	$ 1	$ 1	$ 1
Interest cost on benefit obligation	27	25	24	1	1	1	3	3	3
Expected return on plan assets	(41)	(41)	(40)	-	-	-	(2)	(2)	(2)
Amortization of transition asset	-	-	(2)	-	-	-	1	1	1
Amortization of prior service cost	1	2	2	-	1	1	1	1	-
Recognized (gain) loss	4	2	-	(1)	(1)	(1)	1	1	-
Net periodic benefit cost (income)	$ 4	$ -	$ (4)	$ -	$ 1	$ 1	$ 5	$ 5	$ 3

The estimated amounts that will be amortized from Accumulated OCI into net periodic benefit cost in 2007 are as follows (in millions):

	Pension Benefits	Non-qualified Benefits	Other Benefits
Actuarial (gain)/loss	$ 4	$ 1	$ -
Prior service (credit)/cost	1	-	1
Transition (asset)/obligation	-	-	1
Total	$ 5	$ 1	$ 2

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					
	2007	2008	2009	2010	2011	2012 - 2016
Pension Plan Payments	$ 25	$ 25	$ 25	$ 26	$ 28	$ 167
Non-Qualified Plan Payments	2	2	1	1	2	11
Other Plan Payments	4	4	4	4	4	23
Total	$ 31	$ 31	$ 30	$ 31	$ 34	$ 201

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, an 8.5% annual rate of increase in the per capita cost of covered health care benefits is assumed for 2007. The rate is assumed to decrease to 5% by 2014 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 change in assumed health care cost trend rates would have the following effects (in millions):

	One-Percentage Point Increase	One-Percentage Point Decrease
Effect on total of service and interest cost components	$ -	$ -
Effect on post-retirement benefit obligation	$ 1	$ (1)

The asset allocation for the pension plan at December 31, 2006 and 2005, and the target allocation for 2007, are as follows:

Asset Category	Percentage of Plan Assets December 31		Target Allocation
	2006	2005	2007
Equity Securities	67%	67%	67%
Debt Securities	33%	33%	33%
Total	100%	100%	100%

The asset allocation for the Non-Qualified Benefit Plans at December 31, 2006 and 2005, and the target allocation for 2007, are as follows:

Asset Category	Percentage of Plan Assets December 31		Target Allocation
	2006	2005	2007
Cash Equivalents	1%	10%	-
Debt Securities	11%	7%	16%
Equity Securities	42%	37%	55%
TOLI Policies	46%	46%	29%
Total	100%	100%	100%

An insurable interest in the respective employees is required for investment in TOLI policies. PGE does not establish target allocations between the TOLI assets and the remaining investments.

The asset allocation for the Other Benefit Plans at December 31, 2006 and 2005, and the target allocation for 2007, are as follows:

Asset Category	Percentage of Plan Assets December 31		Target Allocation
	2006	2005	2007
Equity Securities	62%	68%	67%
Debt Securities	38%	32%	33%
Total	100%	100%	100%

The Plans' investment policies call for permanent commitment to five asset classes to promote diversification at the plan level. The commitments to each class are controlled by an Asset Deployment Policy and Cash Management Policy that take 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.

Other Non-Qualified Benefit Plans

In addition to the SERP discussed above, PGE provides certain employees with benefits under unfunded management deferred compensation plans (MDCPs), whereby participants may defer a portion of their pay. Obligations for the MDCPs were $56 million and $54 million at December 31, 2006 and 2005, respectively (not included in table). The costs of the SERP and MDCPs are excluded from prices charged to customers. Investments in trust owned life insurance policies and marketable securities are intended to be the primary source for financing the MDCPs. Total assets held in support of the MDCP Plan were $40 million at December 31, 2006 and $39 million at December 31, 2005. Unrealized gains in marketable securities were $4 million for 2006 and $1 million for 2005 and 2004.

PGE sponsors additional non-qualified plans for certain employees and former directors. Obligations for these plans are minimal. Assets held in support of these plans totaled $1 million at December 31, 2006 and $2 million at December 31, 2005.

In April 2005, PGE assumed $5 million of management deferred compensation plan and directors deferred compensation plan liabilities from PGH as part of a settlement with certain PGH participants. PGE also received $5 million in trust assets to be used for payment of benefits. Obligations for the PGH liabilities were $4 million at December 31, 2006 and 2005. Total trust assets held in support of the PGH liabilities were also $4 million at December 31, 2006 and 2005.

401(k) Retirement Savings Plan

PGE participated in the Enron Corp. Savings Plan during 2004. At the end of 2004, employee balances were transferred from the Enron Corp. Savings Plan to a new 401(k) Plan sponsored by PGE, which became effective on January 1, 2005. Contribution provisions, described below, did not change.

Contributions to the plan by eligible employees, made on a "pre-tax" basis, are matched by the Company up to a specified maximum percentage of the participating employee's base salary. For non-bargaining unit employees, contributions up to 6% of base pay are matched by the Company.

For bargaining unit employees, contributions are based upon provisions of the International Brotherhood of Electrical Workers Local 125 agreement that became effective on March 1, 2004. Contributions to the 401(k) Plan by those employees who are also covered by a defined benefit pension plan are matched by the Company at up to 6% of base pay. Contributions by those employees not covered by a defined benefit pension plan will be matched until 2009 by the Company up to 8% of base pay, based upon both the employee's age and years of service; in addition, PGE contributes from 5% to 10% of base pay, based upon the employee's age.

All contributions to the plan are invested in accordance with employees' individual investment choices. PGE made matching contributions to its employees' savings plan accounts of approximately $13 million in 2006, $13 million in 2005, and $12 million in 2004.

Note 3 - Income Taxes

The following table indicates the detail of taxes on income and the items used in computing the differences between the statutory federal income tax rate and PGE's effective tax rate (dollars in millions):

	2006	2005	2004
Income Tax Expense			
Current:			
Federal	$ 66	$ 88	$ 59
State and local	8	8	8
	74	96	67
Deferred:			
Federal	(29)	(41)	(8)
State and local	(6)	(9)	(2)
	(35)	(50)	(10)
Investment tax credit adjustments	(3)	(3)	(3)
Total income tax expense	$ 36	$ 43	$ 54
Income tax expense allocated to:			
Operations	$ 38	$ 46	$ 57
Other income and deductions	(2)	(3)	(3)
Total income tax expense	$ 36	$ 43	$ 54
Effective Tax Rate Computation:			
Computed tax based on statutory federal income tax rate (35%) applied to income before income taxes	$ 38	$ 37	$ 51
Flow through depreciation	5	7	9
State and local taxes - net of federal tax benefit	2	1	5
Investment tax credits	(3)	(3)	(3)
Excess deferred taxes	(1)	(1)	(1)
Adjustments for previously-recorded taxes	(4)	2	(3)
Other	(1)	-	(4)
Total income tax expense	$ 36	$ 43	$ 54
Effective tax rate	33.5%	39.9%	37.0%

As of December 31, 2006 and 2005, the significant components of PGE's deferred income tax assets and liabilities were as follows (in millions):

	2006	2005
Deferred income tax assets		
Depreciation and amortization	$ 36	$ 35
Employee benefits	72	34
Allowance for uncollectible accounts	19	20
Revenue subject to refund (SB 408)	16	-
Land reclamation costs	-	3
Regulatory liabilities		
Asset retirement removal costs	163	139
Other	19	39
Other	5	17
Total deferred income tax assets	330	287
Deferred income tax liabilities		
Depreciation and amortization	457	463
Employee benefits	25	27
Property taxes	5	5
Price risk management	4	26
Regulatory assets		
Debt reacquisition costs	12	8
Conservation investments	-	3
Energy efficiency programs	-	4
Pension	34	-
Miscellaneous	9	11
Other	13	9
Total deferred income tax liabilities	559	556
Net deferred income taxes	$ 229	$ 269
Classification of net deferred income taxes		
Included in current (assets) liabilities	$ (22)	$ 51
Included in non current liabilities	251	218
Net deferred income taxes	$ 229	$ 269

PGE has recorded deferred tax assets and liabilities for all temporary differences between the financial statement basis and tax basis of assets and liabilities.

Note 4 - Common and Preferred Stock

(Dollars in Millions)	Common Stock			Limited Voting Junior Preferred		
	Number of Shares	$3.75 Par Value	No Par Value	Number of Shares	$1.00 Par Value	Paid-in Capital
December 31, 2004	62,500,000	-	$ 641	1	-	-
December 31, 2005	62,500,000	-	642	1	-	-
December 31, 2006	62,504,767	-	643	-	-	-

Common Stock Issuance

In accordance with Enron's Chapter 11 Plan, on April 3, 2006 PGE issued 62.5 million shares (of 80 million, no par value, shares authorized) of new PGE common stock. Approximately 27 million shares of the new PGE common stock were initially issued to the Debtors' creditors holding allowed claims, and approximately 35.5 million shares were issued to the DCR, where the shares will be held to be released over time to the Debtors' creditors holding allowed claims, in accordance with the Chapter 11 Plan. As of December 31, 2006, approximately 3 million shares of PGE common stock had been released from the DCR, with approximately 32.5 million shares remaining in the DCR. The 42.8 million shares of PGE common stock previously held by Enron were cancelled.

PGE accounted for the stock issuance in the same manner as a stock split and has retroactively adjusted all periods presented. The Company's Consolidated Balance Sheets reflect the combined book values of the $3.75 par value common stock that was cancelled and other paid-in capital into the new item "Common stock, no par value." PGE's Consolidated Statements of Income reflects "Earnings per Average Share" for both current and prior periods, with such amounts based upon the number of outstanding shares of new PGE common stock. Costs incurred for the issuance of new common stock, and for PGE to become a publicly-traded company, were charged to operating expense as incurred.

In addition to the issuance of the 62.5 million shares of new PGE common stock described above, approximately 4.7 million shares have been registered for future issuance pursuant to the Portland General Electric Company 2006 Stock Incentive Plan. For further information regarding PGE's Stock Incentive Plan, see Note 5, Stock-Based Compensation.

Common Stock Dividend Restriction

The OPUC order approving the issuance of new PGE common stock includes a stipulation containing several conditions, including a requirement that, after issuance of the new common stock, PGE cannot pay a dividend that would reduce the Company's common equity capital percentage below 48% of total capitalization (excluding short-term borrowings) without prior OPUC approval. The requirement is reduced to 45% when the DCR holds between 20% and 40% of the issued and outstanding common stock of PGE, with no minimum common equity capital percentage requirement when the DCR holds less than 20% of the outstanding common stock of PGE. At December 31, 2006, the DCR held approximately 52% of the total issued and outstanding common stock of PGE. Other conditions include a requirement that the OPUC be notified (simultaneously with the public) of any dividend declared by PGE's Board of Directors.

Limited Voting Junior Preferred Stock

On March 28, 2006, the $1.00 par value Limited Voting Junior Preferred Stock was redeemed and cancelled and will not be reissued.

Note 5 - Stock-Based Compensation

On July 13, 2006, PGE granted restricted stock units (Stock Units) with time-based vesting conditions (Restricted Stock Units) and performance-based vesting conditions (Performance Stock Units) to non-employee members of the Company's Board of Directors, officers, and certain key employees. Each Stock Unit represents the right to receive one share of the Company's common stock at a future date, subject to applicable vesting requirements. The grants were made pursuant to the terms of the Portland General Electric Company 2006 Stock Incentive Plan, and are subject to the terms and conditions of the plan and individual award agreements between the Company and each grantee. A total of 4,687,500 shares of common stock was registered for future issuance under the plan.

The eight non-employee directors on the Board on July 13, 2006 were initially granted a total of 9,608 Restricted Stock Units as part of their annual compensation. Each of the directors was granted 1,201 units, valued at $30,000 based upon the closing stock price on the grant date. An additional grant of 801 units, valued at $22,500, was made on November 16, 2006 to a newly elected director. The grants vest over a one-year period in equal installments on the last day of each calendar quarter and will be settled exclusively in shares of the Company's common stock, provided that the director remains a member of the Board of Directors. The non-employee director grants also provide for the quarterly payment of dividend equivalent rights (DERs) on the non-vested Restricted Stock Units. The DERs are settled in cash on the date that the related dividends are paid to holders of PGE's common stock, or the cash settlement may be deferred under terms of the Portland General Electric Company 2006 Outside Directors' Deferred Compensation Plan.

PGE also awarded a total of 88,601 Restricted Stock Units and 89,238 Performance Stock Units to officers and certain key employees of the Company. The number of Stock Units was determined by dividing a specified award amount for each grantee by the closing stock price on the grant date. Both Restricted Stock Unit and Performance Stock Unit grants provide for the payment of DERs during the vesting period, which entitle the grantee to receive an amount equal to dividends paid on a share of PGE's common stock between the grant date and the vesting date. The Performance Stock Unit DERs vest on the same schedule as the Performance Stock Units and are settled in shares of PGE common stock valued at the closing stock price on the vesting date. Restricted Stock Unit DERs are valued at each dividend payable date and vest on the same schedule as the Restricted Stock Units.

The Restricted Stock Unit grants to PGE officers provide for vesting over a three-year period in equal installments on each anniversary of the grant date. The Restricted Stock Unit grants to key employees vest at the end of the three-year period following the grant date. Under both officer and key employee grants, applicable service requirements must be met in order for the Restricted Stock Units to vest.

Performance Stock Units for both officers and key employees vest if performance goals related to overall customer satisfaction, electric service power quality and reliability, generating plant availability, and net income (compared to budget) 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 whether and to what extent the performance goals have been met. In accordance with the 2006 Stock Incentive 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.

Restricted Stock Unit activity for 2006 is summarized in the following table:

	Non-employee Directors		Officers and Key Employees	
	Units	Weighted Average Fair Value	Units	Weighted Average Fair Value
Restricted Stock Units:				
Stock units outstanding - January 1, 2006	-	$ -	-	$ -
Stock units granted:				
July 13, 2006 grant	9,608	24.96	88,601	24.96
November 16, 2006 grant	801	28.08	-	-
Stock units forfeited	(901)	24.41	(2,400)	26.88
Stock units vested	(4,767)	25.82	-	-
Stock units outstanding - December 31, 2006	4,741	24.73	86,201	24.91

Performance Stock Unit activity for 2006 is summarized in the following table:

	Officers and Key Employees	
	Units	Weighted Average Fair Value
Performance Stock Units:		
Stock units outstanding - January 1, 2006	-	$ -
July 13, 2006 grant (*)	89,238	24.96
Stock units forfeited	-	
Stock units vested	-	
Stock units outstanding - December 31, 2006	89,238	24.96

(*) Based upon target performance; excludes DER shares.

A total of 4,502,553 shares remain available for future grants. The plan had no material impact on cash flow for the year ended December 31, 2006.

Effective July 1, 2006, PGE adopted SFAS No. 123R, Share-Based Payment, which requires that the compensation cost related to share-based payment transactions be recognized in financial statements at fair value, based on the market price of the underlying common stock on the date of grant, and charged to expense over the vesting period based on the number of shares expected to vest. No compensation cost is recognized for unvested awards that are forfeited. The Company adopted SFAS No. 123R using the Modified Prospective Application method, which applies to new awards and to awards modified, repurchased, or cancelled as of the beginning of the period in which SFAS No. 123R is adopted. For the year ended December 31, 2006, PGE recorded $1 million of stock-based compensation expense (included in Administrative and other expense in the Consolidated Statements of Income), with a corresponding credit to common stock equity. No equity compensation costs were capitalized. Based upon the attainment of performance goals that would allow the vesting of 100% of awarded Performance Stock Units, and utilizing an estimated forfeiture rate of 3%, unrecognized compensation expense related to unvested Stock Units was $3.7 million at December 31, 2006, of which $1.6 million, $1.4 million, and $0.7 million is expected to be expensed in 2007, 2008, and 2009, respectively.

Note 6 - Earnings Per Share

The following table presents the computation of basic and diluted earnings per common share for the years indicated:

	2006	2005	2004
Numerator:			
Net Income (in millions)	$ 71	$ 64	$ 92
Denominator (in thousands):			
Weighted-average common shares outstanding-basic	62,501	62,500	62,500
Effect of dilutive securities:			
Restricted Stock*	4	-	-
Weighted-average common shares outstanding-diluted	62,505	62,500	62,500
Earnings per share - basic	$ 1.14	$ 1.02	$ 1.48
Earnings per share - diluted	$ 1.14	$ 1.02	$ 1.48

* Restricted Stock Units and related Dividend Equivalent Rights granted under the Portland General Electric Company 2006 Stock Incentive Plan are discussed in Note 5, Stock-Based Compensation.

Note 7 - Credit Facility and Debt

At December 31, 2006, PGE had a $400 million five-year unsecured revolving credit facility with a group of commercial banks. The facility, which expires in 2011, is available for general corporate purposes, with the maximum amount available to PGE for borrowings and/or the issuance of standby letters of credit. The facility allows PGE to 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 facility. The facility provides that all outstanding loans mature on the termination date of the facility, provided that annually such date may be extended for an additional year for those lenders who agree to an extension. The facility requires annual fees based on PGE's unsecured credit rating, and contains customary covenants and default provisions, including a requirement that limits consolidated indebtedness, as defined in the facility, to 65% of total capitalization. At December 31, 2006, PGE was in compliance with this covenant.

Pursuant to PGE's application, the Federal Energy Regulatory Commission (FERC) issued an order on February 3, 2006 which authorized the Company to issue short-term debt, including commercial paper, in an amount not to exceed $400 million outstanding at any one time, over the two-year period February 8, 2006 through February 7, 2008. 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. The commercial paper program is supported by the Company's $400 million five-year unsecured revolving credit facility. The amount available under the commercial paper program is limited to the unused line of credit under the revolving credit facility. PGE had $81 million in short-term commercial paper debt outstanding at December 31, 2006 and had utilized approximately $6 million in letters of credit. The Company had no short-term borrowings in 2005.

PGE management believes that its existing line of credit and cash from operations provide the Company with sufficient liquidity to meet its day-to-day cash requirements. 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. Due to the short-term nature of the commercial paper, the fair value of such instruments approximates their book value.

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

	2006	2005	2004
As of year-end:			
Aggregate short-term debt outstanding			
Commercial paper	$ 81	$ -	$ -
Weighted average interest rate*			
Commercial paper	5.5 %	-	-
Unused committed line of credit	$ 313	$ 383	$ 148
For the year ended:			
Average daily amounts of short-term debt outstanding			
Commercial paper	$ 12	$ -	$ -
Weighted daily average interest rate*			
Commercial paper	5.1 %	-	-
Maximum amount outstanding during the year	$ 81	$ -	$ -

* Interest rates exclude the effect of commitment fees, facility fees and other financing fees.

The Indenture securing PGE's First Mortgage Bonds constitutes a direct first mortgage lien on substantially all utility property and franchises, other than expressly excepted property.

Schedule of Long-Term Debt at December 31:	2006	2005
	(In Millions)	
First Mortgage Bonds		
Maturing 2007 - (7.15%)	$ 50	$ 50
Maturing 2010 - (8 1/8%)	-	150
Maturing 2012 - (5.6675%)	100	100
Maturing 2013 - (5.279% - 5.625%)	100	100
Maturing 2021 - 2033 (6.75% - 9.31%)	120	120
Maturing 2031 - (6.26%)	100	-
Maturing 2036 - (6.31%)	175	-
	645	520
Pollution Control Bonds		
Port of Morrow, Oregon, variable rate, due 2033 (5.20% fixed rate to 2009)	23	23
City of Forsyth, Montana, variable rate, due 2033 (5.20% - 5.45% fixed rate to 2009)	119	119
Port of St. Helens, Oregon, 4.80% due 2010	37	37
Port of St. Helens, Oregon, due 2014 (5.25% - 7.13% fixed rate)	15	15
	194	194
Other		
6.91% Conservation Bonds maturing monthly to 2006	-	9
7.875% Notes due March 15, 2010	149	149
7.75% Series Cumulative Preferred Stock (b)	16	19
Unamortized debt discount	(1)	(1)
	164	176
	1,003	890
Long-term debt due within one year (a)	(66)	(11)
Total long-term debt	$ 937	$ 879

(a) Consists of 7.15% First Mortgage Bonds due June 15, 2007 and the 7.75% Series Cumulative Preferred Stock.

(b) The 7.75% Series Cumulative Preferred Stock (no par value), which is mandatorily redeemable, is classified as long-term debt in accordance with SFAS No. 150. The preferred stock series is redeemable by operation of a sinking fund that requires the annual redemption of 15,000 shares at $100 per share beginning in 2002, with all remaining shares to be redeemed by sinking fund in 2007. At its option, PGE may redeem, through the sinking fund, an additional 15,000 shares each year. Open market share purchases can be applied towards the annual redemption requirement. In 2006, PGE redeemed 30,000 shares, consisting of 15,000 shares for the annual sinking fund requirement and 15,000 additional shares acquired at its option. At December 31, 2006, there were 159,727 shares outstanding.

The following principal amounts (in millions) of long-term debt become due through regular maturities for the years indicated:

	2007	2008	2009	2010	2011	Thereafter	Total
Debt Maturities	$66	$ -	$ -	$186	$ -	$751	$1,003

On December 19, 2006, PGE and certain institutional buyers in the private placement market entered into an agreement under which PGE will sell $170 million of PGE's First Mortgage Bonds to the buyers. The bonds are to be issued at the direction of PGE at any time up to, but not later than, June 1, 2007. The bonds will bear interest from the original issue date at an annual rate of 5.80%, and will mature on June 1, 2039. The bonds will be issued pursuant to a Bond Purchase Agreement between PGE and the buyers and under PGE's Indenture of Mortgage and Deed of Trust, dated July 1, 1945, as supplemented, including the Fifty-seventh Supplemental Indenture dated December 1, 2006, between PGE and HSBC Bank USA, National Association (as successor to The Marine Midland Trust Company of New York) in its capacity as trustee. PGE intends to use the proceeds from the sale of the bonds for general corporate purposes, which may include capital expenditures and/or the repayment of existing debt.

Note 8 - Other Financial Instruments

The following methods and assumptions were used to estimate the fair value of each class of financial instrument for which it is practical to estimate.

Cash and cash equivalents, Customer and other receivables, and Accounts payable - These items are reported at their carrying values as these are a reasonable estimate of their fair value.

Other investments - The carrying amounts of other investments are based on the underlying trust investments in marketable securities, consisting of money market, bond, and equity mutual funds, are classified as trading and approximate fair value. These include the Nuclear decommissioning trust, Non-qualified benefit plan trust, and other miscellaneous financial instruments.

Long-term debt - 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. The estimated fair values of debt instruments are as follows (in millions):

	2006		2005	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt including current maturities	$1,003	$1,046	$890	$ 950

Note 9 - Commitments and Guarantees

Natural Gas Agreements

PGE has entered into agreements for the purchase and transportation of natural gas from domestic and Canadian sources for its natural gas-fired generating facilities. The Company has also entered into a ten-year natural gas storage agreement, effective May 1, 2007, for the purpose of fueling the Company's Port Westward and Beaver generating plants located adjacent to the storage facility. As of December 31, 2006, these agreements require net payments of approximately $34 million in 2007, $21 million in both 2008 and 2009, $19 million in 2010, $16 million in 2011, and $70 million over the remaining years of the contracts, which expire at varying dates from 2007 to 2018.

Purchase Commitments

Certain commitments have been made for capital and other purchases for 2007 and beyond. Such commitments total $263 million as of December 31, 2006, reflecting future payment requirements of $221 million in 2007, $34 million in 2008, $6 million in 2009, and $2 million in 2010. Such commitments include those related to construction of Port Westward and the Biglow Canyon Wind Farm, Trojan and Bull Run decommissioning activities, hydro license agreements, information systems, upgrades to production and distribution facilities, and system maintenance work. Termination of these agreements could result in cancellation charges.

Coal and Transportation Agreements

PGE has coal and related rail transportation agreements with take-or-pay provisions of approximately $13 million in 2007, $14 million in 2008, and $4 million annually from 2009 through 2013.

Purchased Power

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 hydro projects whether or not they are operable. Selected information regarding these projects is summarized as follows (dollars in millions):

	Rocky Reach	Priest Rapids	Wanapum	Wells	Portland Hydro
Revenue bonds outstanding at December 31, 2006	$ 380	$ 265	$ 442	$ 208	$ 20
PGE's current share of:					
Output	12.0 %	7.5 %	18.7 %	19.4 %	100 %
Net capability (megawatts)	154	65	194	154	36
PGE's annual cost, including debt service:					
2006	$ 9	$ 3	$ 8	$ 7	$ 4
2005	8	4	7	6	5
2004	8	4	6	6	5
Contract expiration date	2011	*	2009	2018	2017

* Expires at the end of the license term to be determined by the FERC.

PGE's share of debt service costs, excluding interest, is approximately $8 million annually in 2007 and 2008, $9 million in 2009, and $7 million annually in 2010 and 2011. Total minimum payments through the remainder of the contracts are estimated at $55 million.

PGE has executed new agreements with Grant County Public Utility District (Grant), operator of the Priest Rapids and Wanapum projects, for periods corresponding to Grant's new license term, to be determined by the FERC. The new Priest Rapids agreement became effective November 1, 2005. The new Wanapum agreement is effective upon expiration of the current contract and the issuance of a new license to Grant. Under the agreements, Grant will annually determine the output required for its purposes, with PGE required to purchase approximately 25% of the output beyond Grant's needs over the term of the new license, for which PGE will pay a proportional share of the project's debt service and operating costs.

In November 2004, Douglas County PUD (Douglas), owner of the Wells Hydroelectric Project (Project), entered into a settlement with the Colville Confederated Tribes (Colville Tribe) that resolved claims for charges for the use of Colville tribal lands. The settlement, which was approved by the FERC in February 2005, impacted the quantity and price of PGE's share of the output of the Project. The settlement required that Douglas pay a $13.5 million lump sum, convey certain real property, and allocate (at cost) 4.5% of Project's output to the Colville Tribe; such allocation increases to 5.5% for all years after 2018. To fund the $13.5 million payment, PGE and other purchasers of the Project's output entered into a Settlement Endorsement Agreement (Agreement) providing for the sale by Douglas of revenue bonds. The Agreement requires that each purchaser of the Project's output pay their respective share of debt service on the revenue bonds, with PGE's annual share calculated at approximately $350,000. In addition to its share of debt service payments, PGE's share of the Project's output was reduced from 20.3% to 19.4% beginning in April 2005. The effects of both the debt service requirement and the reduction in output were included in projected power costs in PGE's RVM filings approved by the OPUC.

As of December 31, 2006, PGE has power purchase contracts with other counterparties, requiring payments of approximately $665 million in 2007, $214 million in 2008, $77 million in 2009, $78 million in 2010, $77 million in 2011, and $625 million over the remaining years of the contracts, which expire at varying dates from 2012 to 2035. PGE also has power capacity contracts as of December 31, 2006 that require payments of approximately $23 million annually from 2007 through 2011 and are expected to average approximately $19 million from 2012 through 2016. As of December 31, 2006, PGE has power sale contracts with other counterparties of approximately $343 million in 2007, $50 million in 2008, $5 million annually in 2009, 2010, and 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. There was no outstanding exchange balance under this contract at December 31, 2006. The other exchange contract is with a winter-peaking Northwest utility to help meet the Company's summer-peaking power requirements. At December 31, 2006, PGE owed 8,863 MWhs of electricity, all of which are expected to be delivered by the end of February 2007.

Leases

PGE has an operating lease for its headquarters complex located in Portland, Oregon. The Company's Beaver Generating Plant and Port Westward Generating Plant are located on leased property near Clatskanie, Oregon; the lease for this property was extended in 2006 to the year 2096.

Future minimum payments under non-cancelable leases are as follows (in millions):

Year Ending December 31	**Operating Leases (Net of Sublease Rentals)**
2007	$ 8
2008	8
2009	7
2010	7
2011	8
Remainder	227
Total	$265

Included in the above table is approximately $121 million for PGE's headquarters complex, reflecting the base lease period through 2018 and renewal period options through 2043. Also included is $98 million for the generating plant land lease described above.

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 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 lessor 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 2007 is approximately $186 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 finance 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. The Company has not recorded any liability on the Consolidated Balance Sheets with respect to these indemnifications. Based on PGE's historical experience and the evaluation of the specific indemnities, management believes the likelihood that PGE would be required to perform or otherwise incur any significant losses is remote.

Note 10 - Price Risk Management

PGE utilizes derivative instruments, including electricity forward, swap, and option contracts and natural gas forward, swap, option, and futures contracts in its retail (non-trading) electric utility activities to manage its exposure to commodity price risk and to minimize net power costs for service to its retail customers. Under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (as amended), derivative instruments are recorded on the Consolidated Balance Sheets as an asset or liability measured at estimated fair value, with changes in fair value recognized currently in earnings, unless specific hedge accounting criteria are met.

Changes in the fair value of retail (non-trading) derivative instruments prior to settlement that do not qualify for either the normal purchase and normal sale exception or for hedge accounting are recorded on a net basis in Purchased Power and Fuel expense. For derivative instruments that are physically settled, sales are recorded in Operating Revenues, with purchases, natural gas swaps and futures recorded in Purchased Power and Fuel expense. PGE records the non-physical settlement of non-trading electricity derivative activities on a net basis in Purchased Power and Fuel expense, in accordance with EITF No. 03-11, Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, and "Not Held for Trading Purposes."

Special accounting for qualifying hedges allows gains and losses on a derivative instrument to be recorded in OCI until they can offset the related results on the hedged item in the Income Statement. The effects of changes in fair value of derivative instruments entered into to hedge the Company's future non-trading retail resource requirements are subject to regulation; accordingly, the unrealized gains and losses are deferred pursuant to SFAS No. 71.

PGE discontinued its electricity and natural gas trading (non-retail) activities in early 2005. Unrealized and realized gains and losses on the settlement of all derivative instruments related to such activities were reported on a net basis, as required by EITF 02-3, Accounting for Contracts Involved in Energy Trading and Risk Management Activities.

Non-Trading Activities

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. Such activities include power purchases and sales resulting from economic dispatch decisions for its own generation, which allows PGE to secure reasonably priced power for its customers. Most of PGE's non-trading wholesale sales have been to utilities and power marketers and have been predominantly short-term. In this process, PGE may net purchases and sales with the same counterparty rather than simultaneously receiving and delivering physical power. These net transactions are also referred to as "book outs." Only the net amount of those purchases or sales required to fulfill retail and wholesale obligations are physically settled.

Prior to December 2006, PGE recorded a regulatory asset or regulatory liability under SFAS No. 71 to offset unrealized gains and losses on certain non-trading contracts recorded prior to settlement to the extent that such contracts are included in the Company's RVM. Upon settlement, the regulatory asset or regulatory liability is reversed. In its January 2007 general rate order, the OPUC approved a new PCAM by which PGE can adjust future rates to reflect the difference between each year's forecasted and actual net variable power costs on a settlement basis. As a result, a regulatory asset or regulatory liability is recorded to offset changes in fair value of derivative instruments not included in the RVM. Effective January 17, 2007, a new Annual Power Cost Update Tariff replaced the RVM.

The following table indicates unrealized gains and losses recorded in earnings for the years indicated (in millions):

	2006	2005	2004
Non-Trading Activities			
Net unrealized gains (losses)	$ (127)	$ 41	$ 6
SFAS No. 71 regulatory (liability) asset	132	(37)	(22)
Net unrealized gains (losses)	$ 5	$ 4	$ (16)

The following table indicates derivative activities from cash flow hedges recorded in OCI for the years indicated (in millions):

	2006	2005	2004
Derivative Activities Recorded in OCI			
Unrealized holding net gains (losses) arising during the period	$ (42)	$ 46	$ 20
Reclassification adjustment for contract settlements included in net income	(18)	7	(10)
Reclassification adjustment in net income due to discontinuance of cash flow hedges (*)	-	(2)	-
Reclassification of unrealized (gains) losses to SFAS No. 71 regulatory (liability) asset	61	(48)	(16)
Total - Unrealized gains (losses) on derivatives classified as cash flow hedges	$ 1	$ 3	$ (6)

(*) Due to the probability that the original forecasted transactions will not occur.

Hedge ineffectiveness from cash flow hedges was not material in 2006, 2005, and 2004. As of December 31, 2006, the maximum length of time over which PGE is hedging its exposure to such transactions is approximately 57 months. The Company estimates that of the $5 million of net unrealized gains in OCI at December 31, 2006, $1 million will be reclassified into earnings within the next twelve months (fully offset by SFAS No. 71 regulatory liabilities) and the remaining $4 million will be reclassified over the remaining 45 months (fully offset by SFAS No. 71 regulatory liabilities).

Trading Activities

Prior to 2005, PGE utilized forward, swap, option, and futures contracts to participate in electricity and natural gas markets for non-retail purposes. In early 2005, PGE discontinued its trading activities for non-retail purposes, with existing trading transactions settled by December 31, 2005. Such activities were not reflected in PGE's retail prices.

As indicated above, all unrealized and realized gains and losses associated with "energy trading activities" are reported on a net basis for all periods presented. The following tables indicate unrealized and realized gains and losses on electricity and natural gas trading activities and transaction volumes for electricity trading contracts that settled in the years indicated:

	2006	2005	2004
Trading Activities (In Millions)			
Unrealized Gain (Loss)	$ -	$ (1)	$ 1
Realized Gain	-	1	-
Net Gain in Operating Revenues	$ -	$ -	$ 1
Electricity Trading - MWhs (thousands)			
Sales	-	815	9,699
Purchases	-	815	9,699

Note 11 - Jointly Owned Plant

At December 31, 2006, PGE had the following investments in jointly owned generating plants (dollars in millions):

			PGE Interest			
Facility	**Location**	**Fuel**	**Percent**	**MW Capacity**	**Plant In Service**	**Accumulated Depreciation (*)**
Boardman	Boardman, OR	Coal	65.00	380	$418	$ 258
Colstrip 3 and 4	Colstrip, MT	Coal	20.00	296	482	298
Pelton/Round Butte	Madras, OR	Hydro	66.67	298	113	43

(*) Excludes "Asset Retirement Obligations" and "Accumulated Asset Retirement Removal Costs."

Above amounts represent PGE's share of each jointly owned plant, with the Company's share of both direct expenses and utility plant costs included in its financial statements. Each joint owner of the plants has provided its own financing. PGE operates Boardman and Pelton/Round Butte; PPL Montana, LLC operates Colstrip 3 and 4.

Note 12 - Asset Retirement Obligations

Under SFAS No. 143, Accounting for Asset Retirement Obligations, and FASB Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations (FIN 47), PGE recognizes as Asset Retirement Obligations (AROs) those legal obligations associated with the disposal of long-lived assets that result from the acquisition, construction, development or normal operation of such assets. Concurrent with the recognition of the liability, estimated costs of asset retirement obligations are capitalized and depreciated over the remaining life of the asset, with accretion of the ARO liability recorded as an operating expense. On the Statement of Income, amounts are included in Depreciation and Amortization expense for Utility plant and Other Income (Deductions) for Other property.

Regulation - Pursuant to regulation, AROs of rate-regulated long-lived assets are included in depreciation expense and allowed in rates 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 under SFAS No. 71. Substantially all significant AROs are included in rate regulation, and PGE expects any changes in estimated AROs to be incorporated in future rates.

Asset Retirement Obligations - At December 31, 2006, PGE's asset retirement obligations include $108 million associated with the Trojan plant, representing the present value of future decommissioning expenditures. Site specific AROs, totaling $15 million, have also been recognized for rate-regulated utility plant, consisting of the Boardman and Colstrip Units 3 and 4 coal plants, the Coyote Springs, Beaver, and Port Westward gas turbine plants, and the Bull Run hydro project. A $2 million conditional asset retirement obligation, resulting from the adoption and application of FIN 47 in 2005, has been recognized for the disposal cost of assets subject to specific environmental regulation, including costs related to treated pole disposal, mercury vapor light disposal, asbestos remediation, polychlorinated biphenyl (PCB) disposal, underground storage tank removal, and other miscellaneous disposal costs. A total of $9 million in AROs for non-utility property has also been recognized. The following table indicates activity and balances for the Company's AROs included on the Consolidated Balance Sheets for the years indicated (in millions):

	For Year Ended December 31,		
	2006	2005	2004
Beginning Balance	$ 134	$ 120	$ 129
Activity			
AROs incurred	-	2	-
Expenditures	(6)	(4)	(17)
Accretion	7	6	6
Revisions	(1)	10	2
Ending Balance	$ 134	$ 134	$ 120

Unrecognized Asset Retirement Obligations

PGE has certain tangible long-lived assets for which AROs are not currently measurable, the recording of which will be required when circumstances change. Those assets that may require removal when the plant is no longer in service include the Oak Grove hydro project and transmission and distribution plant located on public right-of-ways and on certain easements. Management believes that these assets will be used in utility operations for the foreseeable future.

Note 13 - Trojan Nuclear Plant

Plant Shutdown and Fuel Storage - In 1993, PGE ceased commercial operation of Trojan, in which the Company has a 67.5% ownership share. In May 2005, following completion of radiological decommissioning and approval of the Nuclear Regulatory Commission (NRC), the plant's operating license was terminated. Spent nuclear fuel is stored in the ISFSI, an NRC-approved interim dry storage facility that houses the fuel at the plant site until permanent off-site storage is available.

Decommissioning - The Trojan decommissioning plan includes an estimate of PGE's cost to decommission the plant. The original cost estimate was based upon a site-specific engineering study. A Decommissioning Cost Forecast is maintained and periodically updated by PGE. The cost forecast has been revised to reflect actual costs and changes in the timing of decommissioning activities, due primarily to a delay in the completion of a permanent spent fuel storage facility. At December 31, 2006, the asset retirement obligation, measured at estimated fair value in accordance with SFAS No. 143, is $108 million. (See Note 12, Asset Retirement Obligations, for further information).

ASSET RETIREMENT OBLIGATION (ARO) (In Millions)

Balance, 12/31/05	$	107
2006 Expenditures		(5)
2006 Accretion		6
Balance, 12/31/06	$	108
Total expenditures through 12/31/06	$	215

Remaining decommissioning activities consist of demolition of the existing structures, operation of the ISFSI to the year 2030, and decommissioning of the ISFSI. Final site restoration activities are anticipated to begin in 2031 following shipment of spent fuel to a United States Department of Energy (USDOE) facility (see "Nuclear Fuel Disposal and Cleanup of Federal Plants" below).

DECOMMISSIONING TRUST ACTIVITY
(In Millions)

		2006		2005
Beginning Balance	$	31	$	22
Activity				
Contributions		14		14
Earnings		1		1
Disbursements		(4)		(6)
Ending Balance	$	42	$	31

PGE's retail prices through 2006 included recovery of $14 million annually for decommissioning costs, with an equal amount recorded in amortization expense. Due to revised cost estimates, annual recovery has been reduced to $4.65 million and extended from 2011 through 2024, with such reduction reflected in new prices, as authorized by the OPUC, effective January 17, 2007. Such amounts are deposited in a trust fund, which is limited to reimbursing PGE for activities covered in Trojan's decommissioning plan. Funds are withdrawn as required to cover general decommissioning costs and operation of the ISFSI. In addition, the OPUC, in its January 2007 order in PGE’s general rate case, approved the refund to customers of approximately $20 million from the trust fund, representing accrued savings on prior decommissioning activities.

Decommissioning trust funds are invested in a diversified portfolio of fixed income securities. Year-end balances are valued at market. Earnings on the trust fund are used to reduce decommissioning costs collected from customers. PGE expects any future changes in estimated decommissioning costs to be incorporated in future revenues collected from customers.

Nuclear Fuel Disposal and Cleanup of Federal Plants - PGE has contracted with the USDOE for permanent disposal of spent nuclear fuel in federal facilities and paid for such services, based on Trojan's generation, during the period of plant operation. The availability of an off-site repository for the permanent storage of radioactive waste would allow PGE to remove spent nuclear fuel from the ISFSI and allow final decommissioning and release of the ISFSI site for unrestricted use. Significant delays have occurred in the USDOE acceptance schedule for spent fuel from domestic utilities, with no federal repository expected to be available until after 2010.

In 2002, the USDOE formally recommended Yucca Mountain, Nevada as the nation's first long-term geologic (underground) repository for high-level radioactive waste produced in the United States. The proposed location is based on the conclusions of scientific studies of the site, conducted over 20 years, which support a finding of suitability, as mandated by the Nuclear Waste Policy Act and various regulations of the NRC, USDOE, and the U.S. Environmental Protection Agency (EPA). The House and Senate approved the site and in 2002, President Bush signed the Yucca Mountain resolution into law. Lawsuits have been filed objecting to the recommendation of Yucca Mountain as a nuclear waste repository. Based upon updated information received from the USDOE regarding the acceptance of spent nuclear fuel from Trojan, PGE has extended its projection for the final shipment of spent fuel from 2023 to 2030. Although it has not yet submitted the required application for an operating license for the repository, the USDOE in July 2006 announced plans to submit a license application to the NRC by June 30, 2008. Further delays may make it difficult for PGE to move its spent nuclear fuel, currently contained in the ISFSI, to permanent underground storage by 2030.

In 2004, the co-owners of Trojan (PGE, Eugene Water & Electric Board, and PacifiCorp) filed a complaint against the USDOE in the U.S. Court of Federal Claims for failure to accept spent nuclear fuel by January 31, 1998, as required by the Standard Form Contract. The plaintiffs paid for permanent disposal services during the period of plant operation (in the total amount of $109 million) and have met all other conditions precedent. Damages sought are in excess of $200 million.

The Energy Policy Act of 1992 provided for the creation of a Decontamination and Decommissioning Fund to finance the cleanup of USDOE gas diffusion plants, with funding provided by both domestic nuclear utilities and the federal government. Contributions are based upon each utility's share of total enrichment services purchased by all domestic utilities prior to enactment of the legislation. PGE's $17 million share of the total funding requirement, based on Trojan's 1.1% usage of total industry enrichment services, was paid in annual installments from 1993 through 2006.

Security Requirements - In response to the terrorist attacks of September 11, 2001, the NRC issued interim compensatory security measures for a generalized high-level threat environment at closed nuclear reactors that are in the decommissioning process and at ISFSIs. The new requirements are expected to remain in effect until the NRC determines that the level of threat has diminished, or that other security changes are needed. The NRC issued additional security orders to all operating reactors in 2003 that require operating plants to update their defensive strategies to counter a highly organized attack. It is possible that corresponding similar orders (limited in scope) will eventually be issued to the Trojan ISFSI. Until NRC requirements associated with any new orders are determined, any implementation costs (including their impact on the Trojan decommissioning cost estimate and related funding requirements) are not determinable. However, as any new security requirements are evaluated, any additional costs will be determined and decommissioning cost estimates revised as necessary.

Nuclear Insurance - The Price-Anderson Amendment of 1988 limits public liability claims that could arise from a nuclear incident and also provides for loss sharing among all owners of nuclear reactor licenses. Because Trojan has been permanently de-fueled, PGE has been exempted by the NRC from participation in the secondary financial protection pool covering losses in excess of $300 million at other nuclear plants. The NRC has also reduced the required primary nuclear insurance coverage for Trojan to $100 million and has allowed PGE to self-insure for on-site decontamination related to spent nuclear fuel stored in the ISFSI. PGE continues to insure non-contamination property, in the amount of $18.5 million, under the Company's "All Risk" property insurance on the Trojan plant.

Trojan ISFSI Pollution Control Tax Credits - PGE received final certification from the OEQC related to $21.1 million in Oregon pollution control tax credits that were generated from PGE's investment in the ISFSI. The OEQC rules require that the tax credits be spread over a ten-year period, beginning in 2004. Accordingly, PGE records a regulatory liability to defer the utilization of these tax credits for future refund to customers.

Note 14 - Legal and Environmental Matters

Legal Matters

Trojan Investment Recovery - In 1993, following the closure of the Trojan Nuclear Plant as part of its least cost planning process, PGE sought full recovery of, and a rate of return on, its Trojan plant costs, including decommissioning, in a general rate case filing with the OPUC. In 1995, the OPUC issued a general rate order which granted the Company recovery of, and a rate of return on, 87% of its remaining investment in Trojan plant costs, and full recovery of its estimated decommissioning costs through 2011.

Numerous challenges, appeals and reviews were subsequently filed in the Marion County 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, stating that the OPUC does not have the authority to allow PGE to recover a return on the Trojan investment, but upholding the OPUC's authorization of PGE's recovery of the Trojan investment and ordering remand of the case to the OPUC. PGE, the OPUC, and URP each requested the Oregon Supreme Court to conduct a review of the Court of Appeals decision. On November 19, 2002, the Oregon Supreme Court dismissed the petitions for review. As a result, the 1998 Oregon Court of Appeals opinion stands and the case has been remanded to the OPUC (1998 Remand).

In 2000, while the petitions for review of the 1998 Court of Appeals decision were pending at the Oregon Supreme Court, 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. URP did not participate in the settlement. The settlement, which was approved by the OPUC in September 2000, 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 largest of such amounts consisted of before-tax credits of approximately $79 million in customer benefits related to the previous settlement of power contracts with two other utilities and the approximately $80 million remaining credit due customers under terms of the 1997 merger of the Company's parent corporation at the time (Portland General Corporation) with Enron. The settlement also allowed PGE recovery of approximately $47 million in income tax benefits related to the Trojan investment which had been flowed through to customers in prior years; such amount was substantially recovered from PGE customers by the end of 2006. After offsetting the investment in Trojan with these credits and prior tax benefits, the remaining Trojan regulatory asset balance of approximately $5 million (after tax) was expensed. As a result of the settlement, PGE's investment in Trojan is no longer included in rates charged to customers, either through a return of or a return on that investment. Authorized collection of Trojan decommissioning costs is unaffected by the settlement agreements or the OPUC orders.

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 URP's challenges, and approving the accounting and ratemaking elements of the 2000 settlement. URP appealed the 2002 Order to the Marion County Circuit Court. On November 7, 2003, the Marion County Circuit Court issued an opinion remanding the case to the OPUC for action to reduce rates or order refunds (2003 Remand). The opinion does not specify the amount or timeframe of any reductions or refunds. PGE and the OPUC have appealed the 2003 Remand to the Oregon Court of Appeals.

The OPUC combined the 1998 Remand and the 2003 Remand into one proceeding and is considering the matter in phases. The first phase addresses what rates would have been if the OPUC had interpreted the law to prohibit a return on the Trojan investment. The subsequent phases will address reconciling the results of the first phase with actual rates, and adjusting rates to the extent necessary. On November 15, 2006, PGE filed a motion with the OPUC to Consolidate Phases and Re-Open the Record. A ruling on the motion is pending.

On February 16, 2007, the Oregon Court of Appeals declined to reverse or abate the 2003 Remand and ordered the parties to file revised briefs with the Court of Appeals.

In a separate legal proceeding, two class action suits were filed in Marion County Circuit Court against PGE on January 17, 2003 on behalf of two classes of electric service customers. One 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 other 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 for the Current Class and $70 million for the Former Class, as a result of the inclusion of a return on investment of Trojan in the rates PGE charges 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 responds to the 2003 Remand (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 rate reductions or refunds, for any amount of return on the Trojan investment PGE collected in rates for the period from April 1995 through October 2000. The Supreme Court further stated that if the OPUC determines that it can provide a remedy to PGE's customers, then the class action proceedings may become moot in whole or in part, but if the OPUC determines that it cannot provide a remedy, and that decision becomes final, the court system may have a role to play. The Supreme Court also ruled that the plaintiffs retain the right to return to the Marion County Circuit Court for disposition of whatever issues remain unresolved from the remanded OPUC proceedings. 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 February 14, 2005, PGE received a Notice of Potential Class Action Lawsuit for Damages and Demand to Rectify Damages from counsel representing Frank Gearhart, David Kafoury and Kafoury Brothers, LLC (Potential Plaintiffs), stating that Potential Plaintiffs intend to bring a class action lawsuit against the Company. Potential Plaintiffs allege that for the period from October 1, 2000 to the present, PGE's electricity rates have included unlawful charges for a return on investment in Trojan in an amount in excess of $100 million. Under Oregon law, there is no requirement as to the time the lawsuit must be filed following the 30-day notice period. No action has been filed to date.

Management cannot predict the ultimate outcome of the above matters. However, it believes these matters will not have a material adverse impact on the financial condition of the Company, but may have a material impact on the results of operations and cash flows for a future reporting period. No reserves have been established by PGE for any amounts related to this issue.

Multnomah County Business Income Taxes - In January 2005, David Kafoury and Kafoury Brothers, LLC filed a class action lawsuit in Multnomah County Circuit Court against PGE on behalf of all PGE customers who were billed on their electric bills and paid amounts for Multnomah County Business Income Taxes (MCBIT) after 1996 that the plaintiffs alleged were never paid to Multnomah County. The plaintiffs sought judgment against PGE for restitution of MCBIT in excess of $6 million, plus interest, recoverable costs, punitive damages, and attorney fees.

On July 28, 2006, the Multnomah County Circuit Court approved a settlement providing for PGE refunds and payments totaling $10 million, inclusive of interest and plaintiffs' attorney fees, costs, and expenses as approved by the Court's final order. The settlement includes no admission of liability or wrongdoing by the Company. PGE established a reserve of $10 million in 2005 related to the settlement. Refunds to customers were completed in the fourth quarter of 2006.

Colstrip Royalty Claim - Western Energy Company (WECO) supplies coal from the Rosebud Mine in Montana under a Coal Supply Agreement and a Transportation Agreement with owners of Colstrip Units 3 and 4, in which PGE has a 20% ownership interest. In 2002 and 2003, WECO received two orders from the Office of Minerals Revenue Management of the U.S. Department of the Interior which asserted underpayment of royalties and taxes by WECO related to transportation of coal from the mine to Colstrip during the period October 1991 through December 2001. WECO subsequently appealed the two orders to the Minerals Management Service (MMS) of the U.S. Department of the Interior. On March 28, 2005, the appeal by WECO was substantially denied. On April 28, 2005, WECO appealed the decision of the MMS to the Interior Board of Land Appeals of the U.S. Department of the Interior. In late September 2006, WECO received an additional order from the Office of Minerals Revenue Management to report and pay additional royalties for the period January 2002 through December 2004.

In May 2005, WECO received a "Preliminary Assessment Notice" from the Montana Department of Revenue, asserting claims similar to those of the Office of Minerals Revenue Management.

WECO has indicated to the owners of Colstrip Units 3 and 4 that, if WECO is unsuccessful in the above appeal process, it will seek reimbursement of any royalty payments by passing these costs on to the owners. The owners of Colstrip Units 3 & 4 advised WECO that their position would be that these claims are not allowable costs under either the Coal Supply Agreement or the Transportation Agreement.

Management cannot predict the ultimate outcome of the above matters or estimate any potential loss. Based on information currently known to the Company's management, the Company does not expect that this issue will have a material adverse effect on its financial condition, results of operations or cash flows. If WECO is able to pass any of these costs on to the owners, the Company would most likely seek recovery through the ratemaking process.

City of Portland Challenge of Stock Issuance - On February 10, 2006, the City of Portland appealed the OPUC order approving distribution of the new PGE common stock in both the Marion County Circuit Court and the Oregon Court of Appeals. On July 19, 2006, the Court of Appeals granted the OPUC motion to dismiss the action before that Court. On October 20, 2006, the City of Portland filed a Notice and Order of Voluntary Dismissal with the Marion County Circuit Court. On November 2, 2006, the Marion County Circuit Court dismissed the case.

Environmental Matters

Harborton - A 1997 investigation by the EPA of a 5.5 mile segment of the Willamette River known as the Portland Harbor revealed significant contamination of sediments within the harbor. The EPA subsequently included the Portland Harbor on the federal National Priority List pursuant to the federal Comprehensive Environmental Response, Compensation, and Liability Act (Superfund). In December 2000, PGE received a "Notice of Potential Liability" regarding its Harborton Substation facility and was listed, along with sixty-eight other companies, on a list of Potentially Responsible Parties (PRPs) with respect to the Portland Harbor Superfund Site.

In February 2002, PGE provided a report on its remedial investigation of the Harborton site to the DEQ. The report concluded that there is no likely present or past source or pathway for release of hazardous substances to surface water or sediments in the Portland Harbor Superfund Site at or from the site and that the site does not present a high priority threat to present and future public health, safety, welfare, or the environment. The DEQ submitted the report to the EPA and, in a May 18, 2004 letter, the EPA notified the DEQ that based on the summary information from the DEQ and the stage of the process, the EPA as of that time, agreed the Harborton site does not appear to be a current source of contamination to the river.

In December 6, 2005 letter, the DEQ notified PGE that the site is not likely a current source of contamination to the river and that the site is a low priority for further action. Management believes that the Company's contribution to the sediment contamination, if any, from the Harborton Substation site would qualify it as a de minimis PRP.

Sufficient information is currently not available to determine either the total cost of investigation and remediation of the Portland Harbor or the liability of PRPs, including PGE. Management cannot predict the ultimate outcome of this matter or estimate any potential loss. However, it believes this matter will not have a material adverse impact on the Company's financial statements.

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 is also 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 that impacted an approximate two acre area. Elevated levels of contaminants, including metals, pesticides, and PCBs, have been detected at the site. On September 29, 2003, Harbor Oil was included on the federal National Priority List as a federal Superfund site.

PGE received a Special Notice Letter for Remedial Investigation/Feasibility Study 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. The letter started a period for the PRPs to participate in negotiations with the EPA to reach a settlement to conduct or finance a Remedial Investigation and Feasibility Study of the Harbor Oil site. PGE, along with other PRPs, is negotiating an Administrative Order of Consent with the EPA to conduct a Remedial Investigation/Feasibility Study.

Sufficient information is currently not available to determine either 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. However, it believes this matter will not have a material adverse impact on the Company's financial statements.

Note 15 - Receivables and Refunds on Wholesale Market Transactions

Receivables - California Wholesale Market

As of December 31, 2006, PGE has net accounts receivable balances totaling approximately $63 million from the California Independent System Operator (ISO) and the California Power Exchange (PX) for wholesale electricity sales made from November 2000 through February 2001. The Company estimates that the majority of this amount was for sales by the ISO and PX to Southern California Edison Company and Pacific Gas & Electric Company.

In March 2001, the PX filed for bankruptcy and in April 2001, Pacific Gas & Electric Company filed a voluntary petition for relief under the provisions of Chapter 11 of the federal Bankruptcy Code. PGE filed a proof of claim in each of the proceedings for all past due amounts. Although both entities have emerged from their bankruptcy proceedings as reorganized debtors, not all claims filed in the proceedings, including those filed by PGE, have been resolved. PGE is continuing to pursue collection of these claims.

Management continues to assess PGE's exposure relative to these receivables. Based upon FERC orders regarding the methodology to be used to calculate refunds related to California wholesale sales (see "Refunds on Wholesale Transactions" below) and the FERC's indication that potential refunds can be offset with accounts receivable related to such sales, PGE has established reserves totaling $40 million related to this receivable amount. The Company is examining numerous options, including legal, regulatory, and other means, to pursue collection of any amounts ultimately not received through the bankruptcy process.

Refunds on Wholesale Transactions

California

On July 25, 2001, the FERC issued an order in the California refund case (Docket No. EL00-95) establishing the scope of and methodology for calculating refunds for wholesale sales transactions made between October 2, 2000 and June 20, 2001 in the spot markets (defined by the FERC as 24 hours or less) operated by the ISO and PX. The order established evidentiary hearings to develop a factual record to provide the basis for the refund calculation. Several additional orders clarifying and further defining the methodology were issued by the FERC and all have been appealed by numerous parties. A hearing was held in 2002 and, on March 26, 2003, the FERC issued an order ruling on various outstanding issues as to how refunds were to be determined. Under this order, PGE estimates its potential liability at between $40 million and $50 million, of which $40 million has been established as a reserve, as discussed above.

Numerous parties, including PGE, filed requests for rehearing of various aspects of the March 26, 2003 order, including the methodology for the pricing of natural gas within the refund formula. On October 16, 2003, the FERC issued an order reaffirming, in large part, the methodology adopted in its March 26, 2003 order. PGE does not agree with the FERC's methodology for determining potential refunds, and, on December 20, 2003 the Company appealed the FERC's October 16, 2003 order to the U.S. Ninth Circuit Court of Appeals; several other parties have also appealed the October 16, 2003 order. On May 12, 2004, the FERC issued an order that denied further requests for rehearing of the October 16, 2003 order. Although there continue to be miscellaneous orders issued in the underlying FERC proceeding, the Ninth Circuit has now begun to hear the numerous appeals. It bifurcated appeals of the existing cases into two phases. The first phase (Phase I) considered arguments regarding jurisdictional issues and the permissible scope of refund liability, both in terms of the time frame for which refunds were ordered and the types of transactions subject to refund. The second phase will consider the issues relating to the refund methodology itself. PGE expects that the Court will establish additional phases as the issues remaining before the FERC become final and are appealed.

As to the jurisdictional issues in Phase I, on September 6, 2005, the Court ruled that the FERC did not have jurisdiction to order municipal utilities and other governmental entities to make refunds for the sales they had made to the ISO and PX that are the subject of the refund proceeding. Requests for rehearing have been filed with regard to this decision.

On August 2, 2006, the Ninth Circuit issued its decision on the remainder of the issues in Phase I (Refund Scope Decision). It upheld the refund effective date of October 2, 2000, but remanded to the FERC the issue of whether it should order refunds for the summer 2000 period pursuant to its authority under Section 309 of the Federal Power Act (FPA) to remedy tariff violations. It also affirmed the FERC's orders on the scope of the refund proceeding, except with regard to the FERC's exclusion of ISO and PX contracts in excess of 24 hours and energy exchanges, and held that transactions in the ISO and PX markets with a duration in excess of 24 hours, as well as energy exchanges, should be included within the scope of the refund case. Although the August 2, 2006 Ninth Circuit decision did not mandate industry-wide refunds for the summer 2000 period, it is possible that, upon remand, the FERC could decide to order such additional refunds. Management cannot predict the outcome of any proceeding or how summer refunds, if they are ordered, might be calculated.

The Ninth Circuit has ordered an extension of the due date for the filing of requests for rehearing of its Refund Scope Decision until April 29, 2007, establishing a mediation process and urging the parties to use the time to assess possibilities of settlement.

Within the refund case, the FERC also issued a series of orders that permit generators serving California to recover certain costs of emission allowances and the costs of fuel incurred to generate power that were in excess of the gas cost component used to establish the refund liability. Under the methodology adopted by the FERC to allocate fuel costs, PGE could be required to pay additional amounts in those hours when it was a net buyer in California spot markets, thus increasing its net refund liability. PGE does not expect a material increase in the Company's potential refund exposure. Partly as a means of limiting its exposure to additional fuel costs and other potential refund liabilities, PGE has opted to become a participant in several settlements filed in the refund case since 2004.

In August 2005, PGE joined in a settlement agreement resolving issues relating to the allocation of the wind-up costs of the PX for both past and future periods. The settlement has been approved by the FERC. Although under the agreement PGE will bear certain additional costs associated with PX obligations to conduct and finalize refund calculations, PGE does not expect those costs to be material to its financial statements.

In several of its underlying refund orders, the FERC has indicated that if marketers, such as PGE, believe that the level of their refund liability has caused them to incur an overall revenue shortfall for their sales to the ISO and PX during the refund period, they will be permitted to file a cost study to prove that they should be permitted to recover additional revenues in excess of the mitigated prices in order to cover their costs. By order issued August 8, 2005, the FERC provided guidelines regarding the manner in which these studies should be conducted and the principles that should govern their preparation. On September 14, 2005, PGE filed a cost recovery study with the FERC. By order issued November 2, 2006, the FERC accepted, subject to PGE making certain additional revisions, a revised cost recovery study that had been filed by PGE in response to an earlier January 26, 2006 order. Pursuant to the November 2, 2006 order, PGE filed a final cost study with the ISO that now reflects an approximate $19.8 million cost offset to its refund obligation. Third parties have challenged PGE's cost recovery filings and made numerous requests that they be rejected in their entirety or that the cost offset be reduced to zero. PGE has filed responses to those challenges.

PGE believes that the FERC erred in certain findings in its orders regarding PGE's cost recovery and has filed requests for rehearing as to several issues in those orders. Due to the continuing uncertainty related to these matters, PGE has made no adjustment to the $40 million reserve previously established for the Company's potential liability, as described above.

The FERC has indicated that any refunds PGE may be required to pay related to California wholesale sales (plus interest from collection date) can be offset by accounts receivable (plus interest from due date) related to sales in California (see "Receivables - California Wholesale Market" above). In addition, any refunds paid or received by PGE applicable to spot market electricity transactions on and after January 1, 2001 in California may be eligible for inclusion in the calculation of net variable power costs under the Company's power cost adjustment mechanism in effect at that time. This could further mitigate the financial effect of any refunds made or received by the Company.

Challenge of the California Attorney General to Market-Based Rates - On March 20, 2002, the California Attorney General filed a complaint with the FERC against various sellers in the wholesale power market, alleging that the FERC's authorization of market-based rates violated the FPA, and, even if market-based rates were valid under the FPA, that the quarterly transaction reports required to be filed by sellers, including PGE, did not contain the transaction-specific information mandated by the FPA and the FERC. The complaint argued that refunds for amounts charged between market-based rates and cost-based rates should be ordered. The FERC denied the challenge to market-based rates and refused to order refunds, but did require sellers, including PGE, to re-file their quarterly reports to include transaction-specific data. The California Attorney General appealed the FERC's decision to the Ninth Circuit. On September 8, 2004, the Court issued an opinion upholding the FERC's authority to approve market-based tariffs, but also holding that the FERC had the authority to order refunds, if quarterly filing of market-based sales transactions had not been properly made. The Court required the FERC, upon remand, to reconsider whether refunds should be ordered. On October 25, 2004, certain parties filed a petition for rehearing with the Court. On July 31, 2006, the Court summarily denied rehearing, and on December 28, 2006, PGE joined with other parties in filing a petition for certiorari of this decision with the U.S. Supreme Court. On February 5, 2007, the California Attorney General filed in opposition to the petition for certiorari, or, in the alternative if the petition is granted, a cross-petition for certiorari challenging the legality of market-based rate tariffs.

In the refund case and in related dockets, including the above challenge to market based rates, the California Attorney General and other California parties have argued that refunds should be ordered retroactively to at least May 1, 2000. Management cannot predict the outcome of these proceedings or whether the FERC will order refunds retroactively to May 1, 2000, and if so, how such refunds would be calculated.

Anomalous Bidding Allegations
By order issued on June 25, 2003, the FERC instituted an investigation into allegations of anomalous bidding activities and practices ("economic withholding") on the part of numerous parties, including PGE. The FERC determined that bids above $250 per MW in the period from May 1, 2000 through October 2, 2000 may have violated tariff provisions of the ISO and the PX. The FERC required companies that bid in excess of $250 per MW to provide information on their bids to the FERC investigation staff. PGE responded to the FERC's inquiries and, on May 12, 2004, the FERC investigation staff issued to PGE a letter terminating the investigation as to the Company without further action. On March 10, 2005, certain California parties filed appeals with the Ninth Circuit, contesting the FERC's conduct of the investigation of the anomalous bidding allegations and the issuance of the dismissal letters.

Pacific Northwest
In the July 25, 2001 order, the FERC also 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 July 2003, numerous parties filed requests for rehearing of the June 2003 FERC order. In November 2003 and February 2004, the FERC issued orders that denied all pending requests for rehearing. Parties have appealed various aspects of these FERC orders. Briefing has been completed and oral argument was held on January 8, 2007. A decision in the case is pending.

Management cannot predict the ultimate outcome of the above matters related to wholesale transactions in California and the Pacific Northwest. However, it believes that the outcome will not have a material adverse impact on the financial condition of the Company, but may have a material impact on the results of operations and cash flows for future reporting periods.

Note 16 - Utility Rate Treatment of Income Taxes

In 2005, the Oregon legislature passed a law that adjusts the way that PGE and other Oregon investor-owned electric and gas utilities recover income tax expense from customers through revenues for utility services. The law, commonly referred to as SB 408, 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 utilities or their consolidated group. The new law requires that utilities file a report with the OPUC each year regarding the amount of taxes paid by the utility or its consolidated group (with certain adjustments), as well as the amount of taxes authorized to be collected in rates, as defined by the statute. This report is to be 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 establish an "automatic adjustment clause" to adjust rates. The first adjustment under the automatic adjustment clause applies only to taxes paid to units of government and collected from customers on or after January 1, 2006.

On September 14, 2006, the OPUC issued a final order (Final Order) that adopted permanent rules (Rules) to implement SB 408. In the Rules, the OPUC adopted the use of fixed reference points for margins and effective tax rates from a ratemaking proceeding. The OPUC also adopted a methodology to determine the amounts properly attributed to the utility from a consolidated tax payment using a formula to determine the ratio of the utility's payroll, property and sales to the consolidated group's amounts for the same items. This ratio is then multiplied by the amount of total taxes paid by the consolidated group to determine the utility's attributed portion. The OPUC also determined that interest should begin to accrue beginning January 1, 2006 using a mid-year convention for differences between income taxes collected and income taxes paid to governmental entities for tax year 2006.

In the Final Order, the OPUC addressed the so-called "double whammy" effect wherein the application of the Rules can result in unusual outcomes in certain situations. If a utility incurs higher expenses or receives lower revenues, resulting in lower taxes paid than the OPUC assumed it would incur in its last rate case, the automatic adjustment clause under SB 408 will require the utility to make a refund to customers and decrease the utility's earnings. Conversely, if a utility incurs lower expenses or receives higher revenues, resulting in higher taxes paid than the OPUC assumed it would incur in its last rate case, the automatic adjustment clause under SB 408 will surcharge customers and increase the utility's earnings. The OPUC stated in the Final Order that it will be responsive to concerns related to the consequences of the "double whammy" problem, and may address those concerns in other regulatory proceedings; however, it did not provide clear guidance on avenues of relief.

On December 30, 2005, PGE filed with the OPUC an application for deferred accounting to prevent either the financial enrichment or financial harm to the Company should the rules implementing SB 408 include the use of fixed reference points for margins and effective tax rates from a ratemaking proceeding. The Rules do use fixed reference points for margins and effective tax rates from a ratemaking proceeding. The deferred amount would reflect the tax effect of the difference between PGE's implied operating costs under a fixed margin assumption and the Company's actual operating costs. In an interim order in the rulemaking process, the OPUC indicated that it would review deferral applications related to SB 408 on a case by case basis, but would view such applications with skepticism.

Effective with the April 3, 2006 issuance of new PGE common stock, PGE is no longer a subsidiary of Enron and files its own consolidated tax returns and remits payments directly to taxing authorities. However, in April 2006, PGE paid $17 million to Enron for net current taxes payable for the first quarter of 2006 when PGE was still included in Enron's consolidated group for filing consolidated federal and state income tax returns. Under the Rules, PGE will likely be required to refund to customers the majority of this amount.

As a result of its assessment of the Rules, PGE has estimated its potential refunds to customers to be approximately $42 million (including $2 million of accrued interest) for 2006 and has recorded a (pre-tax) reserve of such amount for the year. In accordance with the statute, the Company will file a report with the OPUC by October 15, 2007 for the 2006 tax year regarding the amount of taxes paid by the Company as well as the amount of taxes authorized to be collected in rates, as defined by the statute. Any refunds to customers for the 2006 tax year would begin after June 1, 2008.

PGE will continue to evaluate its options for changing or modifying the legislation and Rules, and challenging any adjustment that follows for the 2006 tax year.

Complaint and Application for Deferral - Income Taxes - On October 5, 2005, the Utility Reform Project and Ken Lewis (Complainants) filed a Complaint with the OPUC alleging that, since September 2, 2005 (the effective date of SB 408), PGE's rates are not just and reasonable and are in violation of SB 408 because they contain approximately $92.6 million in annual charges for state and federal income taxes that are not being paid to any government. The Complaint requests that the OPUC order the creation of a deferred account for all amounts charged to ratepayers 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.

Also on October 5, 2005, the Complainants filed an Application for Deferred Accounting with the OPUC, claiming that PGE is charging ratepayers $92.6 million annually for federal and state income taxes that are not being paid, and that such charges are not fair, just and reasonable. The Application for Deferred Accounting requests that the portion of PGE's revenue representing estimated PGE liabilities for federal and state income taxes, less any amounts of federal and state income taxes paid by PGE or on behalf of PGE, be deferred for later incorporation in rates. PGE opposes the deferral and has moved to dismiss the Complaint.

On July 10, 2006, the OPUC commenced proceedings on the Complaint and Deferral. Management cannot predict the ultimate outcome of this matter or estimate any potential loss.

Note 17 - Related Party Transactions

The tables below detail the Company's related party balances and transactions (in millions):

	December 31, 2006	December 31, 2005
Payables to affiliated companies		
Enron Corp:		
Accounts Payable[a]	$ -	$ 4
Income Taxes Payable[b]	-	25

[a] Included in Accounts payable and other accruals on the Consolidated Balance Sheets
[b] Included in Accrued taxes on the Consolidated Balance Sheets

For the Years Ended December 31	2006	2005	2004
Expenses billed from affiliated companies			
Enron Corp:			
Intercompany services[a]	$ (1)	$ 7	$ 28
Expenses billed to affiliated companies			
PGH II, Inc. and its subsidiaries:			
Intercompany services[a]	-	-	1

[a] Included in Administrative and other on the Consolidated Statements of Income

Effective with the April 3, 2006 issuance of new PGE common stock, PGE is no longer a subsidiary of Enron. PGE and its subsidiaries are no longer included in Enron's consolidated tax return and file their own consolidated tax returns and remit payments directly to taxing authorities.

Enron incurred costs related to the resolution of issues associated with its bankruptcy and litigation related to certain employee benefit plans in which PGE employees previously participated. Enron billed PGE for a portion of these costs as work continued toward resolution of the issues. At December 31, 2005, PGE had $4 million payable to Enron related to these costs. Final resolution of the issues resulted in a $1 million reduction in the amount payable to Enron and a corresponding reduction in Administrative and other expense. In March 2006, PGE paid the remaining $3 million balance due to Enron.

As PGE was included in Enron's consolidated income tax return prior to April 3, 2006, the Company made payments to Enron for PGE's income tax liabilities. The $25 million income taxes payable to Enron at December 31, 2005 represents a net current income taxes payable for the fourth quarter of 2005 that was paid to Enron in January 2006. In April 2006, PGE paid Enron $17 million for net current income taxes payable for the first quarter of 2006.

In 2005, Enron billed PGE approximately $7 million for insurance coverage and costs related to the resolution of certain employee benefit plan matters (described above). In 2004, Enron billed PGE approximately $28 million, consisting of $25 million for medical/dental benefits and retirement savings plan matching and $3 million for insurance coverage.

Note 18 - Subsequent Event

On February 12, 2007, the OPUC issued an order granting a portion of PGE's request to defer excess power costs associated with the unplanned outage of the Boardman coal plant incurred from November 18, 2005 to February 5, 2006. The order authorizes the Company to defer $26.4 million, with amortization to be determined in a future ratemaking proceeding that will include a prudency review of PGE's actions with respect to the outage and acquisition of replacement power and a determination as to whether recovery of the deferred amount will cause PGE's earnings to exceed a reasonable range. In its order, the OPUC indicated that the outage was significant, unique and outside the foreseen range of risk for forced outages.

Based upon prior OPUC actions, the stated position of the OPUC staff in the proceeding, and considering the applicable accounting guidance and the impact of SB 408 on any benefit received by the Company, PGE recorded a deferral in the amount of $6 million at December 31, 2006. The remaining $20.4 million will be recorded as a reduction in power costs in 2007.

Boardman was taken out of service from October 22, 2005 to February 5, 2006 for repairs to the plant's steam turbine rotor. The extended outage required that PGE replace its portion of the plant's generation with both higher cost purchases in the wholesale market and increased generation from the Company's natural gas-fired generating plants. On November 18, 2005, PGE filed with the OPUC an "Application for Deferred Accounting of Excess Power Costs Due to Plant Outage". The application requested an order authorizing the Company to defer for later ratemaking treatment excess power costs associated with Boardman's outage during the period from the November 18, 2005 application date through February 5, 2006. The application requested deferral of approximately $46 million, representing the difference between Boardman's variable power costs used in setting rates for 2005 and 2006 (under PGE's Resource Valuation Mechanism) and replacement power costs incurred during the outage. Application by the OPUC of a sharing mechanism between PGE customers and shareholders, as well as certain reductions to PGE's estimate of the net cost of the Boardman outage, resulted in a reduction from PGE's $46 million requested deferral to the $26.4 million authorized.

QUARTERLY COMPARISON FOR 2006 AND 2005 (Unaudited)

	Quarter Ended				
	March 31	June 30	September 30	December 31	Total
	(In Millions, Except per Share Amounts)				
2006					
Operating revenues	$ 381	$ 351	$ 372	$ 416	$ 1,520
Net operating income (a)	6	41	20	54	121
Net income (loss) (a)	(6)	27	10	40	71
Basic earnings (loss) per common share (b)	$ (0.10)	$ 0.43	$ 0.16	$ 0.64	$ 1.14
Diluted earnings (loss) per common share (b)	$ (0.10)	$ 0.43	$ 0.16	$ 0.64	$ 1.14
2005					
Operating revenues	$ 371	$ 333	$ 355	$ 387	$ 1,446
Net operating income (a)	53	32	36	5	126
Net income (loss) (a)	38	16	19	(9)	64
Basic earnings (loss) per common share (b)	$ 0.61	$ 0.26	$ 0.30	$ (0.15)	$ 1.02
Diluted earnings (loss) per common share (b)	$ 0.61	$ 0.26	$ 0.30	$ (0.15)	$ 1.02

(a) Operating results for the fourth quarter of 2005 and first quarter of 2006 include $25 million and $26 million, respectively, after-tax effects of excess power costs incurred to replace the output of the Boardman coal plant, which was taken out of service on October 22, 2005 for repair of the plant's steam turbine rotor and which remained out of service for most of the first half of 2006. For further information, see "Boardman Coal Plant - Repair Outages" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

Operating results for the third quarter of 2006 include the $13 million after-tax effect of a reserve for a potential refund obligation to customers related to PGE’s current estimate of the impact of SB 408. For further information, see "Utility Rate Treatment of Income Taxes" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

(b) Earnings per share are computed independently for each quarter presented. Therefore, the sum of the quarterly earnings per share amounts may not equal the total for the year.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

(a) **Disclosure Controls and Procedures**

Management of the Company, under the supervision and with the participation of the Chief Executive Officer and 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, 2006, the Company's internal control over financial reporting is effective.

Management's assessment of the effectiveness of the Company's internal control over financial reporting, as of December 31, 2006, 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 on the following page, which expresses unqualified opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting, as of December 31, 2006.

(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 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Report of Independent Registered Public Accounting Firm

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

We have audited management's assessment, included in the accompanying Management's Report on Internal Control over Financial Reporting, that Portland General Electric Company and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2006, 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 maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit 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 effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides 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, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on the criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2006, of the Company and our report dated March 1, 2007, expressed an unqualified opinion on those financial statements and financial statement schedule and included an explanatory paragraph regarding the adoption of Statement of Financial Accounting Standards No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*, on December 31, 2006.

Deloitte & Touche LLP
Portland, Oregon
March 1, 2007

Item 9B. Other Information

None.

Part III

Item 10. Directors and Executive Officers of the Registrant

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 - Policies on Business Ethics and Conduct,” and "Proposal 1: Election of Directors - The Board of Directors” in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the Securities and Exchange Commission in connection with the Annual Meeting of Shareholders to be held on May 2, 2007.

Information regarding executive officers of PGE is set forth in Part I in accordance with General Instruction G(3), pursuant to Instruction 3 to Item 401(b) of Regulation S-K.

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 "Compensation Discussion and Analysis" and “Executive Compensation” in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the Securities and Exchange Commission in connection with the Annual Meeting of Shareholders to be held on May 2, 2007.

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 caption "Security Ownership of Certain Beneficial Owners, Directors and Executive Officers," in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the Securities and Exchange Commission in connection with the Annual Meeting of Shareholders to be held on May 2, 2007.

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 - Certain Relationships and Related Person Transactions" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the Securities and Exchange Commission in connection with the Annual Meeting of Shareholders to be held on May 2, 2007.

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 Securities and Exchange Commission in connection with the Annual Meeting of Shareholders to be held May 2, 2007.

Part IV

Item 15. Exhibits, Financial Statement Schedules

(a) **Index to Financial Statements and Financial Statement Schedules** — **Page**

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Exhibits

See Exhibit Index on Page 149 of this report.

Portland General Electric Company and Subsidiaries
Schedule II - Consolidated Valuation and Qualifying Accounts
For the Years Ended December 31, 2006, 2005, and 2004
(In Millions)

	Allowance for Uncollectible Accounts
Balance at January 1, 2004	$ 124
Provision charged to income	11
Amounts written off, less recoveries	(85)
Balance at December 31, 2004	50
Balance at January 1, 2005	50
Provision charged to income	7
Amounts written off, less recoveries	(7)
Balance at December 31, 2005	50
Balance at January 1, 2006	50
Provision charged to income	7
Allowance transferred to Assets from price risk management activities	(5)
Amounts written off, less recoveries	(7)
Balance at December 31, 2006	$ 45

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.

Portland General Electric Company

March 2, 2007

By /s/ Peggy Y. Fowler
Peggy Y. Fowler
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 and on the dates indicated.

/s/ Peggy Y. Fowler Peggy Y. Fowler	Chief Executive Officer and President and Director (principal executive officer)	March 2, 2007
/s/ James J. Piro James J. Piro	Executive Vice President, Finance Chief Financial Officer and Treasurer (principal financial and accounting officer)	March 2, 2007
*John W. Ballantine	Director	March 2, 2007
Rodney L. Brown, Jr.	Director	
*David A. Dietzler	Director	March 2, 2007
*Mark B. Ganz	Director	March 2, 2007
*Corbin A. McNeill, Jr.	Director	March 2, 2007
*Neil J. Nelson	Director	March 2, 2007
*M. Lee Pelton	Director	March 2, 2007
*Maria M. Pope	Director	March 2, 2007
*Robert T.F. Reid	Director	March 2, 2007

*By /s/ Kirk M. Stevens
(Kirk M. Stevens, Attorney-in-Fact)

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES

EXHIBIT INDEX

Number		Exhibit
(3)		**Articles of Incorporation and Bylaws**
3.1	*	Amended and Restated Articles of Incorporation of Portland General Electric Company [Form 8-K filed April 3, 2006, Exhibit (3.1)].
3.2	*	Portland General Electric Company Fourth Amended and Restated Bylaws [Form 8-K filed November 20, 2006, 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 fiscal year ended December 31, 1990, Exhibit (4)].
4.3	*	Forty-First Supplemental Indenture dated December 1, 2001 [Form 10-K for the fiscal year ended December 31, 1991, Exhibit (4)].
4.4	*	Forty-Fifth Supplemental Indenture dated May 1, 1995 [Form 10-Q for the quarter ended June 30, 1995, Exhibit (4)].
4.5	*	Forty-Seventh Supplemental Indenture dated December 14, 2001 [Form 10-K for the fiscal year ended December 31, 2001, Exhibit (4)].
4.6	*	Fifty-sixth Supplemental Indenture dated May 1, 2006 [Form 8-K filed May 25, 2006, Exhibit (4)].
4.7	*	Fifty-seventh Supplemental Indenture dated December 1, 2006 [Form 8-K filed December 21, 2006, Exhibit (4)].
		Certain instruments defining the rights of holders of other long-term debt of PGE are omitted pursuant to Item 601(b)(4)(iii)(A) of Regulation S-K because the total amount authorized under each such omitted instrument does not exceed 10 percent of the total assets of PGE and its subsidiaries on a consolidated basis. PGE hereby agrees to furnish a copy of any such instrument to the SEC upon request.
(10)		**Material Contracts**
10.1	*	Residential Purchase and Sale Agreement with the Bonneville Power Administration [Form 10-K for the fiscal year ended December 31, 1981, Exhibit (10)].
10.2	*	Power Sales Contract and Amendatory Agreement Nos. 1 and 2 with Bonneville Power Administration [Form 10-K for the fiscal year ended December 31, 1982, Exhibit (10)].

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES

EXHIBIT INDEX

Number		Exhibit
10.3	*	Separation Agreement between Enron Corp. and Portland General Electric Company dated April 3, 2006 [Form 8-K filed April 3, 2006, Exhibit (10.1)].
		The following 12 exhibits were filed in conjunction with the 1985 Boardman/Intertie Sale:
10.4	*	Long-term Power Sale Agreement dated November 5, 1985 [Form 10-K for the fiscal year ended December 31, 1985, Exhibit (10)].
10.5	*	Long-term Transmission Service Agreement dated November 5, 1985 [Form 10-K for the fiscal year ended December 31, 1985, Exhibit (10)].
10.6	*	Participation Agreement dated December 30, 1985 [Form 10-K for the fiscal year ended December 31, 1985, Exhibit (10)].
10.7	*	Lease Agreement dated December 30, 1985 [Form 10-K for the fiscal year ended December 31, 1985, Exhibit (10)].
10.8	*	PGE-Lessee Agreement dated December 30, 1985 [Form 10-K for the fiscal year ended December 31, 1985, Exhibit (10)].
10.9	*	Asset Sales Agreement dated December 30, 1985 [Form 10-K for the fiscal year ended December 31, 1985, Exhibit (10)].
10.10	*	Bargain and Sale Deed, Bill of Sale, and Grant of Easements and Licenses, dated December 30, 1985 [Form 10-K for the fiscal year ended December 31, 1985, Exhibit (10)].
10.11	*	Supplemental Bill of Sale dated December 30, 1985 [Form 10-K for the fiscal year ended December 31, 1985, Exhibit (10)].
10.12	*	Trust Agreement dated December 30, 1985 [Form 10-K for the fiscal year ended December 31, 1985, Exhibit (10)].
10.13	*	Tax Indemnification Agreement dated December 30, 1985 [Form 10-K for the fiscal year ended December 31, 1985, Exhibit (10)].
10.14	*	Trust Indenture, Mortgage and Security Agreement dated December 30, 1985 [Form 10-K for the fiscal year ended December 31, 1985, Exhibit (10)].
10.15	*	Restated and Amended Trust Indenture, Mortgage and Security Agreement dated February 27, 1986 [Form 10-K for the fiscal year ended December 31, 1997, Exhibit (10)].

EXHIBIT INDEX

Number		Exhibit
		Executive Compensation Plans and Arrangements
10.16	*	Portland General Electric Company Management Deferred Compensation Plan, dated March 12, 2003 [Form 10-Q for the quarter ended March 31, 2003, Exhibit (10)].
10.17	*	Portland General Electric Company Severance Pay Plan for Executive Employees, dated June 15, 2005 [Form 10-K filed June 20, 2005, Exhibit (10)].
10.18	*	Portland General Electric Company Outplacement Assistance Plan, dated June 15, 2005 [Form 10-K filed June 20, 2005, Exhibit (10)].
10.19	*	Portland General Electric Company 2005 Management Deferred Compensation Plan, dated March 4, 2005 (Form 10-K for the fiscal year ended December 31, 2004).
10.20	*	Portland General Electric Company Supplemental Executive Retirement Plan, dated March 12, 2003 [Form 10-Q for the quarter ended March 31, 2003, Exhibit (10)].
10.21	*	Portland General Electric Company Senior Officers' Life Insurance Benefit Plan, dated March 12, 2003 [Form 10-Q for the quarter ended March 31, 2003, Exhibit (10)].
10.22	*	Portland General Electric Company Umbrella Trust for Management, dated March 12, 2003 [Form 10-Q for the quarter ended March 31, 2003, Exhibit (10)].
10.23	*	Portland General Electric Company 2006 Stock Incentive Plan [Form 8-K filed February 22, 2006, Exhibit (10)].
10.24	*	Portland General Electric Company 2006 Annual Cash Incentive Master Plan [Form 8-K filed March 17, 2006, Exhibit (10.1)].
10.25	*	Portland General Electric Company 2006 Outside Directors' Deferred Compensation Plan [Form 8-K filed May 17, 2006, Exhibit (10.1)].
10.26	*	Form of Directors' Restricted Stock Unit Agreement [Form 8-K filed July 14, 2006, Exhibit (10.1)].
10.27	*	Form of Officers' Performance Stock Unit Agreement [Form 8-K filed July 14, 2006, Exhibit (10.2)].
10.28	*	Form of Officers' Restricted Stock Unit Agreement [Form 8-K filed July 14, 2006, Exhibit (10.3)].
(23)		**Consents of Experts and Counsel**
23.1		Consent of Independent Registered Public Accounting Firm Deloitte & Touche LLP (filed herewith).

PORTLAND GENERAL ELECTRIC COMPANY
AND SUBSIDIARIES

EXHIBIT INDEX

Number	Exhibit
(24)	**Power of Attorney**
24.1	Power of Attorney (filed herewith).
(31)	**Rule 13a-14(a)/15d-14(a) Certifications**
31.1	Certification of Chief Executive Officer of Portland General Electric Company (filed herewith).
31.2	Certification of Chief Financial Officer of Portland General Electric Company (filed herewith).
(32)	**Section 1350 Certifications**
32	Certifications of Chief Executive Officer and Chief Financial Officer of Portland General Electric Company Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).

*** Incorporated by reference as indicated.**

Note: The Exhibits furnished to the Securities and Exchange Commission with the Form 10-K will be supplied upon written request and payment of a reasonable fee for reproduction costs. Requests should be sent to:

Kirk M. Stevens
Controller and Assistant Treasurer
Portland General Electric Company
121 SW Salmon Street, 1WTC 0501
Portland, OR 97204

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-135726 on Form S-8 of our reports dated March 1, 2007, relating to the consolidated financial statements of Portland General Electric Company and subsidiaries (which report expresses an unqualified opinion and includes an explanatory paragraph regarding the adoption, on December 31, 2006, of Statement of Financial Accounting Standards No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans*) and management's report on the effectiveness of 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, 2006.

DELOITTE & TOUCHE LLP

Portland, Oregon
March 1, 2007

EXHIBIT 31.1

CERTIFICATION OF
CHIEF EXECUTIVE OFFICER
OF PORTLAND GENERAL ELECTRIC COMPANY

I, Peggy Y. Fowler, 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: March 2, 2007

/s/ Peggy Y. Fowler
Peggy Y. Fowler
Chief Executive Officer and
President

EXHIBIT 31.2

CERTIFICATION OF
CHIEF FINANCIAL OFFICER
OF PORTLAND GENERAL ELECTRIC COMPANY

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: March 2, 2007

/s/ James J. Piro
James J. Piro
Executive Vice President, Finance
Chief Financial Officer and Treasurer

EXHIBIT 32

CERTIFICATIONS OF
CHIEF EXECUTIVE OFFICER AND CHIEF FINANCIAL OFFICER
OF PORTLAND GENERAL ELECTRIC COMPANY
PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

We, Peggy Y. Fowler, Chief Executive Officer and President, and James J. Piro, Executive 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, 2006, 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/ Peggy Y. Fowler
Peggy Y. Fowler
Chief Executive Officer and President

Date: March 2, 2007

/s/ James J. Piro
James J. Piro
Executive Vice President, Finance
Chief Financial Officer and Treasurer

Date: March 2, 2007