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, 2007
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:
None

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

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

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

Indicate by check mark 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, a non-accelerated filer, or a smaller reporting company. See definition of "large accelerated filer," "accelerated filer," and "Smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☒	Accelerated filer ☐	Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

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

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 $1,715,275,306. The number of shares of Portland General Electric Company's common stock outstanding at February 15, 2008 was 62,529,787 shares.

Documents Incorporated by Reference

Part III, Items 10 - 14	Portions of Portland General Electric Company's definitive proxy statement to be filed pursuant to Regulation 14A for the 2008 Annual Meeting of Shareholders to be held on May 7, 2008.

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DEFINITIONS

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

Abbreviations or Acronyms	
AFDC	Allowance For Funds Used During Construction
Beaver	Beaver Combustion Turbine Plant
Biglow Canyon	Biglow Canyon Wind Farm
Boardman	Boardman Coal Plant
BPA	Bonneville Power Administration
Chapter 11 Plan	Supplemental Modified 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
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
ISFSI	Independent Spent Fuel Storage Installation
kWh	Kilowatt-hour
MMBtu	One million British thermal units

DEFINITIONS

Abbreviations or Acronyms

MW	Megawatt
MWa	Average megawatts
MWh	Megawatt-hour
NRC	Nuclear Regulatory Commission
NVPC	Net Variable Power Costs
OATT	Open Access Transmission Tariff
OEQC	Oregon Environmental Quality Commission
OPUC	Public Utility Commission of Oregon
PCAM	Power Cost Adjustment Mechanism
PGE or the Company	Portland General Electric Company
Port Westward	Port Westward Power Plant
RVM	Resource Valuation Mechanism
SB 408	Oregon Senate Bill 408
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

Part I

Item 1. Business

General

Portland General Electric Company (PGE, or the Company), incorporated in 1930, is a publicly owned, vertically 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 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 is obligated to provide full (bundled) service to all of its customers. The Company continues to operate as a single segment, with revenues and costs related to its business activities maintained and analyzed on a total electric operations basis.

In 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. In December 2001, Enron, along with certain of its subsidiaries, filed for Chapter 11 of the federal Bankruptcy Code. PGE was not included in the filing.

On April 3, 2006, in accordance with Enron's Chapter 11 Plan, the 42.8 million shares of PGE common stock held by Enron Corp. were cancelled, PGE issued 62.5 million shares of new common stock, and PGE and Enron entered into a separation agreement. Following issuance of the new PGE common stock, PGE ceased to be a subsidiary of Enron. 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). On June 18, 2007, the Disputed Claims Reserve sold substantially all of its remaining holdings of PGE stock in a public offering. PGE's common stock is listed on the New York Stock Exchange under the ticker symbol "POR".

PGE's state-approved service area allocation of approximately 4,000 square miles is located entirely within Oregon and includes 52 incorporated cities, of which Portland and Salem are the largest. The Company estimates that at the end of 2007 its service area population was approximately 1.6 million, comprising about 43% of the state's population. The Company added approximately 11,000 retail customers during 2007, and at December 31, 2007 served approximately 804,000 retail customers.

As of December 31, 2007, PGE had 2,705 employees. A total of 868 employees are covered under agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 837 employees for a five-year period effective from March 1, 2004 through February 28, 2009. In addition, 31 employees (18 at Coyote Springs and 13 at Port Westward) are covered under a five-year agreement that extends from August 2, 2006 through August 1, 2011.

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 Internet 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.

Regulation and Rates

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

Federal Regulation

The Company is a "licensee" and a "public utility," as those terms are defined in the Federal Power Act, and is subject to regulation by the Federal Energy Regulatory Commission (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 (EPAct 2005) granted the FERC increased statutory authority to implement mandatory transmission and reliability standards, as well as enhanced oversight of power and transmission markets, including protection against market manipulation. Such standards, the majority of which apply to PGE, became effective on June 18, 2007. PGE has submitted mitigation plans related to certain standards to the Western Electricity Coordinating Council (WECC), with review and approval pending.

Wholesale - PGE has authority under its FERC tariff to charge market-based rates for wholesale energy sales. In June 2007, the FERC issued Order 697, *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, which changed the re-authorization requirements for continued use of market-based rates and requires the filing of updated market studies on a regional schedule. PGE's current authorization, which was due to expire in May 2008, will remain in effect until June 2010, when the Company, as part of the western region, will file for re-authorization.

Transmission - FERC Order 890, *Preventing Undue Discrimination and Preference in Transmission Services*, which became effective in July 2007, requires regional coordination of transmission planning. The order requires greater specificity and more transparency in the Open Access Transmission Tariff (OATT). PGE submitted a compliance filing to incorporate into its OATT the non-rate terms and conditions contained in the order and will submit additional filings to incorporate other provisions of the order. FERC Order 693, *Mandatory Reliability Standards for the Bulk-Power System*, issued in March 2007, approved mandatory reliability standards developed by the North American Electric Reliability Corporation, which is responsible for the enforcement of such standards.

As a major transmitting utility, PGE has participated in several transmission planning efforts in support of the coordinated expansion and enhanced operation of the regional transmission system. The Company will continue to monitor and engage in these efforts although there remains considerable uncertainty regarding their further development.

Pipeline - The Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978 provide FERC authority in matters related to extension, enlargement, safety, and abandonment of jurisdictional pipeline facilities, as well as transportation rates and accounting for interstate natural gas commerce. PGE's 79% interest in the pipeline that provides natural gas to its Beaver and Port Westward plants is subject to this authority.

Nuclear - 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 operating license for the Trojan Nuclear Plant (Trojan), and in early 1996 the NRC and Energy Facility Siting Council (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 Note 13, Trojan Nuclear Plant, in the Notes to Consolidated Financial Statements.

State of Oregon Regulation

PGE is subject to the jurisdiction of the Public Utility Commission of Oregon (OPUC), which approves the Company's retail prices through general rate proceedings and supplemental tariffs and establishes conditions of utility service. Under Oregon law, the OPUC is required 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. Construction of new generating facilities in Oregon requires a permit from the state's EFSC.

General Rate Case - PGE periodically evaluates the need to change its overall general retail electric price structure to sufficiently cover its operating costs and provide a reasonable rate of return. The Company's most recent comprehensive general rate case, approved by the OPUC on January 12, 2007, resulted in an overall price increase of approximately 1.3%. The increase represented 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, which became effective on June 15, 2007. The change in retail prices was based upon a 50% equity capital structure, a 10.1% return on equity, and an overall rate of return of 8.29%. The OPUC had previously approved a 5.1% increase effective January 1, 2007 for projected increased power costs under the Resource Valuation Mechanism.

The Company filed a general rate case on late February 27, 2008 with the OPUC, based on a forecasted 2009 test year, with new prices expected to be effective beginning in January 2009. For further information, see the Overview section of Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

Power Costs - In its general rate order, the OPUC also 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 replaced the former Resource Valuation Mechanism, provides for rate adjustments to reflect updated forecasts of net variable power costs (NVPC) for future calendar years. In addition, a new Power Cost Adjustment Mechanism (PCAM) was approved by the OPUC, effective January 17, 2007. Under the PCAM, PGE can adjust future prices to reflect a portion of the difference between each year's forecasted NVPC included in prices (the baseline), and actual NVPC. Under the PCAM, PGE is subject to a portion of the business risk or benefit associated with the difference between actual NVPC and that included in base prices by application of an asymmetrical deadband within which PGE absorbs cost increases or decreases, with a 90/10 sharing of costs and benefits between customers and the Company outside of the deadband. A refund will occur only to the extent that it results in PGE's actual return on equity (ROE) for that year being no less than 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.

For 2007, the deadband ranged from $11.7 million below, to $23.4 million above, the baseline. PGE's actual NVPC as determined under the PCAM for 2007 were less than the established baseline by $29.4 million. Accordingly, an estimated refund to customers of $16 million was recorded as a regulatory liability and is reflected as an increase to Purchased power and fuel expenses. Any regulatory asset or liability arising from application of the PCAM is subject to the results of a regulated earnings test, with final determination of any customer refund or collection made by the OPUC through a public filing and review. For 2008, the deadband will range from $14 million below, to $28 million above, baseline NVPC.

Retail Customer Choice Program - Implemented in 2002 as part of Oregon's electricity restructuring law, Oregon's customer choice program, along with related regulations and PGE's tariff, allows the Company's commercial and industrial customers direct access to other suppliers of electricity (Electricity Service Suppliers, or ESSs). While "direct access" customers purchase their electricity from other suppliers, PGE continues to deliver the energy to these customers. The program provides for a "transition adjustment" for customers that choose to purchase energy at market prices from investor-owned utilities or from ESSs. Such transition adjustments 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. The retail customer choice program has no material effect on the financial condition or results of operations of the Company.

In 2007, the three ESSs registered to transact business with PGE served a total of 30 customers with a total average load of approximately 250 MWa, representing approximately 19% of PGE's non-residential load and 12% of the Company's total retail load.

Cost-of-service and market price options are also available to PGE's commercial and industrial customers. The Company offers an option by which certain large non-residential customers may, for a minimum three- 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. A total of 31 commercial and industrial customers were receiving service from PGE under market-based pricing options at the end of 2007.

Residential and small commercial customers can purchase electricity from PGE from a portfolio of rate options that include a basic cost-of-service rate, a time-of-use rate, and renewable resource rates. Approximately 60,000 customers have chosen renewable energy options and approximately 1,900 customers have chosen the time-of-use option.

Public Purpose Charge - The restructuring law also provides for a Public Purpose Charge to fund cost-effective conservation measures, new renewable energy resources, and weatherization measures for low-income housing. This charge, equal to 3% of retail revenues, has been extended to 2026 as part of Oregon's Renewable Energy Standards legislation that was passed in 2007. The Company remits amounts collected from retail customers to the Energy Trust of Oregon (ETO) and other agencies for administration of these programs.

Regulatory Accounting - PGE is subject to the provisions of Statement of Financial Accounting Standards No. (SFAS) 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 101, *Regulated Enterprises - Accounting for the Discontinuation of Application of SFAS No. 71*, and Emerging Issues Task Force Issue No. (EITF) 97-4, *Deregulation of the Pricing of Electricity - Issues Related to the Application of SFAS No. 71 and SFAS No. 101.*

Customers and Revenues

PGE conducts retail electric operations exclusively in Oregon within a state-approved service area. Competitors within the Company's service territory include the local natural gas company, which competes in the residential and commercial space heating, water heating, and appliance markets, and fuel oil suppliers, which compete primarily for residential space heating customers. In addition, commercial and industrial customers may choose to purchase their energy requirements from alternative suppliers (ESSs), in accordance with Oregon's electricity restructuring law.

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

	Years Ended December 31,					
	2007		2006		2005	
	Amount	%	Amount	%	Amount	%
Revenues:						
Retail	$1,516	87%	$1,367	90%	$1,305	90%
Wholesale	201	12%	135	9%	116	8%
Other operating revenues	26	1%	18	1%	25	2%
Total revenues	$1,743	100%	$1,520	100%	$1,446	100%

Retail

PGE serves a diverse retail customer base. Residential customers comprise approximately 88% of the Company's total customers, with the remainder comprised of commercial and industrial customers. Total retail revenues for 2007 were fairly evenly divided between residential (49%) and commercial and industrial (51%) customer classes. Residential demand is sensitive to the effects of weather, with demand 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 9% of total retail revenues, they represent nine different commercial and industrial groups, including high technology, paper manufacturing, metal fabrication, health services, and governmental agencies. No single customer represents more than 3% of PGE's total retail load or 2% 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. The Company's wholesale market 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, and purchases and sales of natural gas. Interconnected transmission systems in the western states serve utilities with diverse load requirements and allow the Company to purchase and sell electricity within the region depending upon the relative price and availability of power, water conditions, and seasonal demand.

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 (termed "book outs") rather than simultaneously receiving and delivering physical power, with only the net amount of those purchases or sales required to meet retail and wholesale obligations physically settled.

Other Operating Revenues

Other operating revenues 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.

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."

Power and Fuel Supply

Power Supply

PGE relies upon its existing base of generating resources, as well as short- and long-term power contracts, to meet its customers' energy needs. At December 31, 2007, PGE's total firm resource capacity, including short-term purchase agreements, was approximately 4,627 MW (net of short-term sales agreements of 757 MW).

The Pacific Northwest peak usage season historically occurs in the winter, when residential and commercial heating and lighting demand is highest. PGE's all-time high net system load peak (4,073 MW) occurred in December 1998. The Company's all-time "summer peak" (3,706 MW), driven by unusually warm weather and increased air conditioning demand, occurred in July 2006.

Generation

PGE's current generating portfolio consists of thermal (primarily coal and natural gas), hydro, and wind resources that together provide 2,449 MW of total net capability. See Item 2. - "Properties" for a full listing of PGE's generating facilities.

- **Thermal**
  The Company's thermal generation facilities continued to supply reliable power during 2007. In June 2007, Port Westward, a new 406 MW natural gas fired generating plant, was placed in service at a total cost of $280 million, including allowance for funds used during construction (AFDC).
- **Hydro**
  The Company's lowest cost generating resources are its FERC licensed hydroelectric projects. 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 2008.
- **Wind**
  Biglow Canyon Wind Farm (Biglow Canyon), located in Sherman County, Oregon, is PGE's newest and largest renewable energy project. Phase I of Biglow Canyon, comprised of 76 wind turbines with a total capacity of 125 MW, was completed and placed in service in mid-December 2007 at a total cost of approximately $255 million (including AFDC). Phases II and III of the project are in the advanced planning stages, with an estimated total cost of $700 million to $800 million, including approximately $50 million of AFDC. Phase II is expected to be completed by the end of 2009 and Phase III is expected to be completed by the end of 2010. When completed, the three-phase project is expected to have a total installed capacity of 400 to 450 MW.

Purchased Power

PGE supplements its own generation with short- and long-term wholesale contracts as needed to meet its retail load requirements and provide the most economic mix on a variable cost basis. PGE also has firm contracts, ranging from one to thirty years, to purchase up to 975 MWa of power from counterparties, including Pacific Northwest utilities and the Confederated Tribes of the Warm Springs Reservation of Oregon. The 30-year agreement is 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.”

Mid-Columbia Hydro Matters - The Company has long-term power purchase contracts with certain public utility districts in the State of Washington related to four hydroelectric projects on the mid-Columbia River. The contracts provide approximately 567 MW of firm capacity, and 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 256 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 Guarantees, in the Notes to Consolidated Financial Statements.

<u>Fuel Supply</u>

PGE contracts for natural gas and coal supplies used to fuel the Company’s thermal generating plants. PGE also uses forward, swap, option, and futures contracts to manage its exposure to volatility in natural gas prices. The Company acquires coal and natural gas as follows:

- **Coal**
  - ***Boardman* -** PGE has a purchase agreement that provides coal for Boardman’s operating requirements through 2008. The coal, obtained from surface mining operations in Wyoming, is delivered by rail under two separate ten-year transportation contracts, the terms of which began January 1, 2004. Coal purchases in 2007, totaling 2.6 million tons, contained approximately 0.3% of sulfur by weight. Utilizing low sulfur coal, the plant emitted less than the limit allowed by the 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 a maximum sulfur content of 1.5% by weight. In 2007, actual sulfur content for coal used at Colstrip ranged from approximately 0.59% to 0.78% 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 2007. Utilizing wet scrubbers to minimize SO_2 emissions, the plant operated in compliance with EPA’s source-performance standards.

- **Natural Gas**
  - ***Beaver and Port Westward* -** 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 received authorization from the FERC 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.

Firm gas supplies for Beaver and Port Westward may be purchased up to 72 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 for 2008.

  - ***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, may be purchased up to 72 months in advance. PGE believes that sufficient market supplies of gas are available to fully meet requirements of Coyote Springs for 2008.

- **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. PGE had an approximate 12-day supply of oil at the plant site at December 31, 2007.
  - ***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.

Reliability

Wholesale power market products, along with PGE's base of thermal, hydroelectric and wind generating capacity, currently provide the Company with 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. PGE anticipates that generating capacity within the WECC, as well as an active wholesale market, will continue to provide sufficient energy to supplement the Company's generation and purchases under current short- and long-term power contracts. To meet anticipated future requirements and help assure continued system reliability, PGE's integrated resource planning process utilizes input from several sources, including long-term forecasts prepared by both PGE and the WECC.

Integrated Resource Plan

PGE's Integrated Resource Plan (IRP), required by the OPUC, describes the Company's energy supply strategy. The primary goal of the IRP is to identify a resource action plan that, when considered with the Company's existing portfolio, provides the best combination of expected cost and associated risks and uncertainties for PGE and its customers.

PGE filed an IRP with the OPUC in June 2007 that covers the years 2008 through 2015. It includes additional renewable and demand-side resources, energy efficiency programs, power purchase agreements of varying terms, and the acquisition of additional peaking capacity. The plan was developed over an 18-month period that included significant research and discussion with customer groups, independent consultants, and regulators.

The IRP Action Plan proposes the following:

- Continued development of Biglow Canyon, with wind turbines to provide a total maximum generating capacity of 400 to 450 MW. Phase I is complete with Phase II expected to be completed by the end of 2009, and Phase III by the end of 2010.
- Procurement of an additional 218 MWa of renewable power. Combined with Biglow Canyon and existing renewable resources, this will help PGE meet Oregon's new Renewable Energy Standard.
- Expansion of energy efficiency programs in partnership with the ETO. The goal is to increase the amount of load met through efficiency measures by an additional 45 MW (beyond the amount already targeted by the ETO) by 2012.
- Purchase power agreements with durations of five to ten years, intended to reduce reliance on spot market purchases, help stabilize customer prices, and meet electricity demand while giving new technologies time to mature and become cost-effective.
- Acquisition of 100 MW of peaking capacity, through ownership or contract, to meet an increase in forecasted winter and summer peak requirements and to facilitate the integration of variable wind generation.
- Seasonal capacity purchases of 508 MW.

Review of the IRP by stakeholders and the OPUC staff is continuing and will be completed when the OPUC determines the Action Plan appears reasonable and issues an acknowledgement order, which is expected in March 2008. The Company expects to issue a Request For Proposal for energy related resources shortly after acknowledgement of the IRP.

Environmental Matters

PGE operates in a state recognized for environmental leadership. The Company's policy of environmental stewardship seeks to minimize environmental risk and waste in its operations and promote the efficient use of energy.

PGE's operations are subject to a wide range of environmental protection laws, including those related to air and water quality, noise, and waste disposal. The EPA and certain state agencies, including 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 that include the siting and operation of generating facilities and the accumulation, cleanup, and disposal of toxic and hazardous wastes.

Climate Change

Greenhouse gas emissions and their potential impacts on climate change and global warming have recently received increased public attention, with several legislative efforts initiated to establish mandatory control of emissions from thermal electricity generating plants. PGE is participating as a stakeholder in the Western Climate Initiative, a regional accord with a stated goal of reducing greenhouse gas emissions to 15% below 2005 levels by the year 2020. Any future laws that impose mandatory reductions in carbon dioxide emissions could have a material impact on electric utilities that rely on coal as a fuel resource. PGE's ownership shares of the Boardman and Colstrip coal plants comprise approximately one-fourth of the Company's net generation capability.

Renewable Energy Standards

Renewable Energy Standards adopted by the 2007 Oregon legislature require that PGE and other large electricity providers serve at least 5% of their retail load within the state from renewable resources by the year 2011, increasing to 25% by 2025. Additional interim steps in the standard include meeting 15% of retail load by 2015 and 20% by 2020. Biglow Canyon, which is expected to have a total installed capacity of 400 to 450 MW when all three phases are completed by the end of 2010, represents a significant step toward the Company's achievement of these goals.

Air Quality Standards

PGE's operations, principally its fossil-fuel generation plants, are subject to the federal Clean Air Act (CAA). Primary pollutants addressed by the CAA that affect PGE are SO_2, nitrogen oxides, carbon monoxide, and particulate matter. 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 currently exceed federal standards.

PGE manages its emissions by the use of low sulfur fuel, emission controls, emission monitoring, and combustion controls. The SO_2 emissions allowances awarded under the CAA, along with expected future annual allowances, are sufficient to operate Boardman at 60% to 67% of capacity. PGE has acquired additional emissions allowances, which, in combination with the allowance awards, are expected to allow PGE to meet the SO_2 emission requirements for the Boardman plant at forecasted capacity for at least the next ten years.

The federal government and the states in which PGE operates have adopted the following regulations concerning mercury emissions:

- In May 2005, the EPA adopted the Clean Air Mercury Rule 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."

- In October 2006, the Montana Board of Environmental Review adopted final rules on mercury emissions from coal-fired generating plants in Montana, including Colstrip, which set strict mercury emission limits by 2010.
- In December 2006, the Oregon Environmental Quality Commission adopted the Utility Mercury Rule, which requires installation of mercury control technology at Boardman and requires that the plant reduce its mercury emissions by 90% by July 1, 2012.
- In February 2008, the U.S. Court of Appeals for the District of Columbia Circuit published a unanimous decision vacating both the EPA's rule delisting coal- and oil-fired electric generating units from regulation under § 112 of the CAA and the Clean Air Mercury Rule. The Oregon Utility Mercury Rule was not directly affected by this decision; however, it contains significant components of the federal Clean Air Mercury Rule and thus it is reasonably likely that amendments will be required if the District of Columbia Circuit decision is not overturned.

In accordance with new federal regional haze rules aimed at visibility impairment in several federally protected areas, the DEQ is conducting an assessment of emission sources pursuant to a Regional Haze Best Available Retrofit Technology (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 a BART Determination.

In response to the EPA's regional haze rules, the Company volunteered to participate in a DEQ pilot project to analyze information about air emissions from Boardman. An exemption modeling analysis for identified sources, which began in September 2006, has indicated that the Boardman and Beaver generating plants may cause or contribute to visibility impairment in several federally protected areas. In November 2007, the Company submitted a BART Determination to the DEQ for Boardman that stated that the BART for Boardman is a combination of New Low NO_x Burners, Modified Over Fire Air System, Selective Non-Catalytic Reduction (SNCR), and Semi-dry Flue Gas Desulphurization, and that mercury emission regulations should be addressed through a Mercury Sorbent Injection System. The cost for these controls is estimated to be in the range of $300 million to $400 million (100% of total costs). While the Company believes that these controls meet BART requirements, it is possible that the regulatory agencies could require Selective Catalytic Reduction rather than SNCR, which would increase the estimated cost to a range of $470 million to $620 million (100% of total costs). The Company has no commitments in place at this time and cautions that the cost estimates are preliminary and subject to change. Final approval of the plan is expected to occur in the second half of 2009.

As the regulatory requirements are clarified by the relevant agencies and the related costs more closely estimated, PGE will further evaluate the economic prudency of these expenditures. In doing so, the Company will also consider additional costs, including taxes, emission fees and other costs that may be imposed under any future laws related to climate change. Such additional costs, as well as the requirement to install Selective Catalytic Reduction controls, could require an investment in excess of what the plant can economically support.

The ultimate impact that the above regulatory requirements and air emission controls will have on future operations, costs, or generating capacity of the Company's thermal generating plants is not yet determinable. PGE will seek to recover its share of any associated costs through the ratemaking process.

Restoration of Salmon Runs

Populations of most salmon species in the Pacific Northwest have declined significantly over the last several decades. Many of these distinct populations of salmon 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. Significant changes thus far include modification in the timing of stored water releases, a spill program to assist juvenile salmon at federal dams located in the Columbia River and Snake River basins, and continued investment in fish protection infrastructure (ladders and screens). These changes have resulted in reductions at times in hydroelectric generation capability and the seasonal shifting of other generation from the fall and winter periods to the spring and summer periods.

PGE is implementing a series of salmon protection measures on the Clackamas, Deschutes, and Willamette rivers that were prescribed by the United States Fish and Wildlife Service and the National Marine Fisheries Service under their authority granted in the ESA and are contained in PGE's FERC operating licenses.

ESA consultations on PGE's Clackamas River project, completed in 2003, will be in effect until a new license is granted by the FERC. 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. Pending issuance of the new license, which is expected to occur in 2009, the project will continue to operate under annual licenses issued by the FERC.

In accordance with a 2002 agreement with state and federal agencies, environmental groups, and others, PGE is proceeding with the decommissioning of the Company's Bull Run hydroelectric project, which includes the Marmot and Little Sandy dams, located in the Sandy River basin. The Marmot Dam was removed in July 2007, with removal of the Little Sandy Dam planned for 2008.

As required under the 50-year license that the FERC issued to PGE in 2004 for its Pelton/Round Butte project on the Deschutes River, PGE began construction of a selective water withdrawal system in late 2007 in an effort to restore fish passage on the upper portion of the river. The system will collect juvenile salmon and steelhead and allow them to bypass the dam when migrating to the Pacific Ocean, and will regulate downstream water temperature. Completion of the system, at a total cost of approximately $105 million to $110 million, is expected in 2009. PGE's portion of the cost is expected to be approximately $80 million, including AFDC.

Hazardous Waste

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

PGE is also subject to regulation under the Comprehensive Environmental Response Compensation and Liability Act (CERCLA), also referred to as Superfund. CERCLA can assert joint and several liability for investigation and remediation costs regardless of fault or legality of original conduct. PGE is currently listed by the EPA as a Potentially Responsible Party (PRP) at two Superfund sites discussed below. Other hazardous waste spills are considered minor, with clean-ups conducted on a regular basis.

Nuclear Fuel Disposal

Under the Nuclear Waste Policy Act of 1982, the U.S. Department of Energy (USDOE) is responsible for the permanent storage and disposal of spent nuclear fuel. PGE has contracted with the USDOE for permanent disposal of spent nuclear fuel for Trojan. Trojan spent nuclear fuel is stored in the Independent Spent Fuel Storage Installation (ISFSI), an NRC-approved interim dry storage facility that houses the fuel at the plant site until the permanent off-site storage is available. No federal repository is expected to be available until after 2017. For further information concerning PGE's nuclear fuel disposal, see Note 13, Trojan Nuclear Plant, in the Notes to the Consolidated Financial Statements.

EPA Actions

PGE is currently involved in two matters, known as Portland Harbor and Harbor Oil, both of which have been included by the EPA on the federal National Priority List as federal Superfund Sites pursuant to CERCLA.

In 2000, PGE, along with sixty-eight other PRPs on the Portland Harbor Initial General Notice List, received a "Notice of Potential Liability" from the EPA with respect to the Portland Harbor Superfund Site. A 1997 investigation of a portion of the Willamette River by the EPA, known as Portland Harbor, revealed significant contamination of sediments within the harbor. In January 2008, PGE received a request from the EPA to provide additional information concerning its properties in or near the Portland Harbor Superfund Site. Sufficient information is currently not available to determine either the total cost of the investigation and remediation of the Portland Harbor or the liability of the PRPs, including PGE.

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 Superfund Site, located in north Portland. Harbor Oil is the location of a company, Harbor Oil, Inc., that PGE and other entities used to process used oil from power plants and electrical distribution systems from at least 1990 until 2003. Sufficient information is currently not available to determine either the total cost of the investigation and remediation of the Harbor Oil site or the liability of the PRPs, including PGE.

For further information regarding these two matters, see "Environmental Matters" in Note 14, Contingencies, in the Notes to Consolidated Financial Statements.

Item 1A. Risk Factors

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

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 prices 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 comprehensive general rate case, issued in January 2007, approved the use of a PCAM by which PGE can adjust future prices to reflect a portion of the difference between each year's forecasted and actual NVPC. 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 PCAM 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.

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. For further information, see "Trojan Investment Recovery" within Legal Matters of Note 14, Contingencies, in the Notes to Consolidated Financial Statements. The Company cannot predict the ultimate outcome of this matter. However, while management believes that it will not have a material adverse impact on the financial condition of the Company, it may have a material adverse impact on results of operations and cash flows for future reporting periods.

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

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 energy 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.

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

Unplanned outages at the Company's generating plants could result in replacement power costs greater than those power costs included in customer prices, and any inability to recover such costs in future rates could have a negative impact on the Company's results of operations. As indicated above, application of the Company's PCAM can be expected to mitigate adverse financial impacts of future unplanned outages at the Company's generating plants.

Weather conditions that reduce stream flows could adversely affect the Company's hydro production and increase the Company's generation or power purchase costs required to meet the shortfall.

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 PCAM.

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 price of purchased power and demand for energy. 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 PCAM can be expected to partially mitigate the financial effects of adverse wholesale market conditions, cost sharing features of the mechanism do not provide for full recovery in customer prices.

Market risk related to adverse fluctuations in the price of natural gas purchased as fuel for electricity generation can also impact the Company's results of operations. PGE purchases natural gas in the open market or pursuant to short-term or variable-price contracts as part of its normal business operations. 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 originally estimated. The Company may not be able to fully recover these increased costs through ratemaking.

Sustained downturns in the economy in its service territory could reduce demand for electricity and adversely affect the Company's results of operations.

Current and projected slowing of the Oregon and national economies could result in reduced demand for electricity that could decrease earnings and cash flow. Economic conditions can also impact the Company's ability to collect accounts receivable.

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

Oregon and federal regulators are currently considering the air emission standards applicable to 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 regulators' reviews. For further information regarding the total costs and the Company's portion, see Environmental Matters in Item 1. - "Business."

In addition, PGE may be subject to litigation brought by environmental groups and other private parties alleging violations of state or federal law and seeking the imposition of penalties, injunctive relief, and the closure of plants. On January 15, 2008, PGE received a "notice of intent to sue" from a coalition of environmental groups alleging violations of the Clean Air Act and the Oregon State Implementation Plan relating to Boardman. The Company has not yet fully evaluated the claims referenced in the notice and cannot determine at this time its estimated exposure, if any. If the plaintiffs file their complaint and articulate their claims in greater detail, PGE will be better able to assess the likelihood, if any, that the claims will have a material adverse effect on the Company.

Montana regulators have adopted strict requirements related to mercury emissions that could impact the operations of Colstrip, in which PGE has a 20% ownership interest in units 3 and 4.

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.

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

Access to capital markets is important to PGE's ability to operate. Increased scrutiny of the energy industry and the impacts of regulation, as well as changes in the Company's financial performance, could result in credit agencies re-examining its credit rating. A ratings downgrade could increase the interest rates and fees on PGE's revolving credit facility, increasing the cost of funding day-to-day working capital requirements, and could also require the Company to pay higher interest rates on future long-term debt. In addition, access to the commercial paper market, a principle source of short-term borrowings, could be restricted, resulting in higher interest costs. The Company's secured and unsecured debt is currently rated at investment grade by Moody's Investors Service and Standard and Poor's. Should Moody's and/or Standard and Poor's reduce their rating on the Company's unsecured debt to below investment grade, PGE could be subject to requests by certain wholesale counterparties to post additional performance assurance collateral.

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

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

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

Increases in both the number of customers and demand for energy will require continued expansion and reinforcement of PGE's generation, transmission, and distribution systems. Construction of new generating facilities, or modifications to existing facilities, 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.

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

A portion of PGE's total energy requirement is comprised of generation from hydroelectric projects on the Columbia, Clackamas, Deschutes, 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.

Legislative efforts to reduce carbon emissions, in response to concerns related to climate change and global warming, could lead to increased capital and operating costs and have an adverse impact on the Company's operations and operating results.

The outcome of legislative efforts regarding carbon dioxide emissions, whether at the federal, regional, or state level, or the timing of any such laws or regulations that may be enacted, could have a material adverse affect on future results of operations and cash flows unless the additional costs incurred to comply with such laws or regulations can be recovered through regulated rates and/or future market prices for electricity. The Company would seek to recover through the ratemaking process any capital and operating costs of additional emission control equipment or emission reduction measures, such as the cost of sequestration or purchasing allowances, or offset credits that may be required.

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

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

Certain legal and regulatory proceedings, such as the proceedings related to refunds on wholesale market transactions in the Pacific Northwest described in Note 14, Contingencies, in the Notes to Consolidated Financial Statements and in Item 3. - "Legal Proceedings," may have an adverse affect on results of operations and cash flows for future reporting periods.

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

PGE is subject to regulation by the FERC and the OPUC, and by federal, state and local authorities under environmental laws. Regulation affects almost every aspect of the Company's business. Changes to these regulations are ongoing, and the Company cannot predict the future course of changes in this regulatory environment or the ultimate effect that this changing regulatory environment will have on the Company's business. However, changes in these regulations can cause delays in or affect business planning and transactions and can substantially increase the Company's costs.

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

The Company anticipates higher than previous averages of retirement rates over the next ten years and may need to replace a significant number of employees in key positions. PGE's ability to successfully implement a workforce succession plan is dependent upon the Company's ability to employ and retain skilled professional and technical workers. Without a skilled workforce, the Company's ability to provide quality service to its customers and meet regulatory requirements will be tested and could affect operating results.

Conditions that may be imposed in connection with hydroelectric license renewals may require large capital expenditures.

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

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

The Company has exposure to natural disasters that can cause significant physical damage to its generation, transmission, and distribution facilities. Such events can interrupt the delivery of electricity, increase repair and service restoration expenses, and reduce revenues. Such events, if repeated or prolonged, can also affect customer satisfaction and the level of regulatory oversight. As a regulated utility, the Company is required to provide service to all customers within its service territory and generally has been afforded liability protection under the tariff against customer claims related to service failures beyond the Company's reasonable control. To the extent reasonably possible, the Company utilizes insurance as a means to mitigate the risk of physical loss of or damage to the Company's property resulting from natural disasters. However, such insurance may be subject to certain coverage restrictions and deductibles.

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

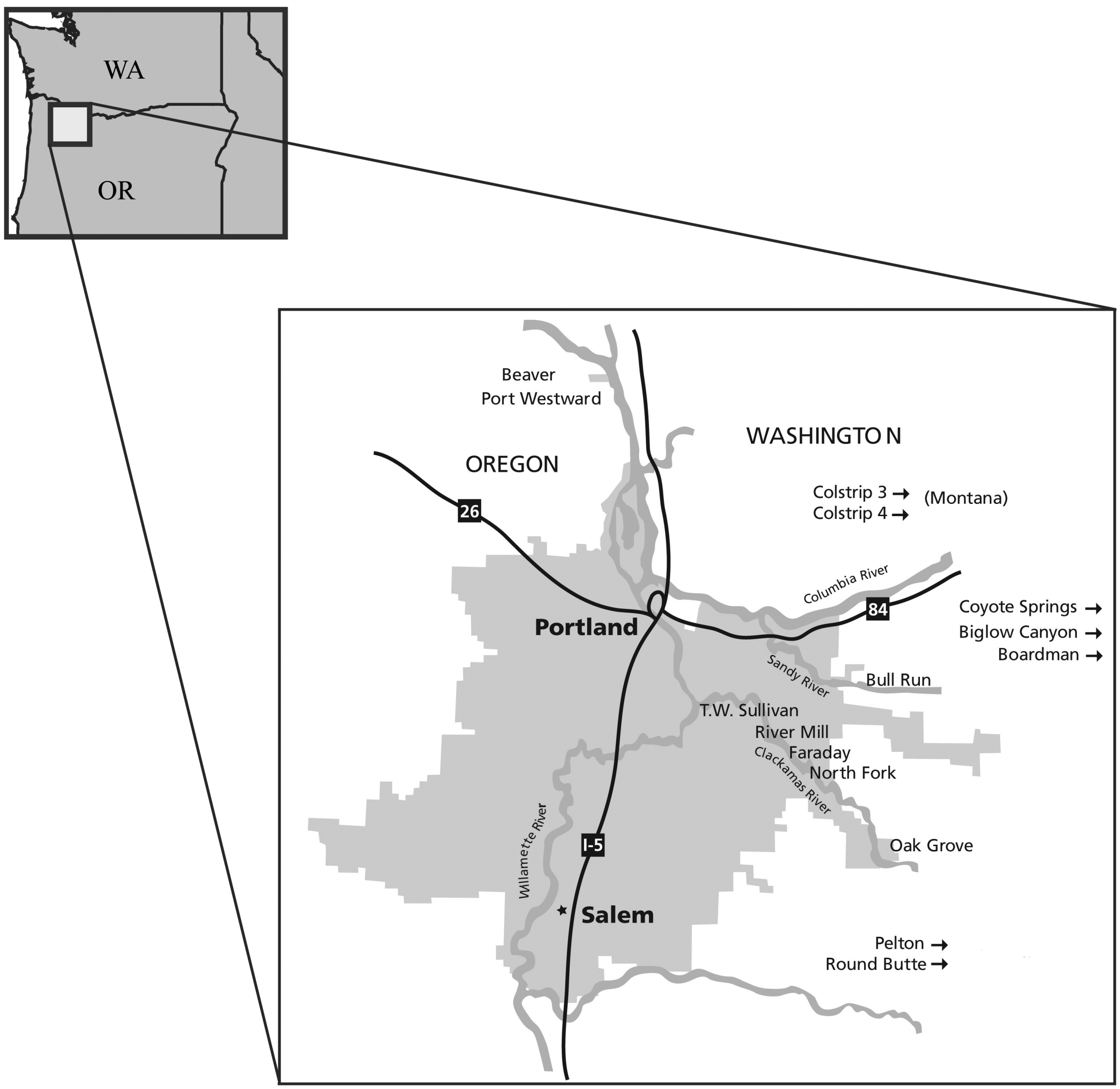
Customer groups in certain geographic areas and certain governmental entities could attempt to acquire PGE facilities and equipment in the Company's allocated service territory through the use of public ownership initiatives, utilizing initiative petition and condemnation processes.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

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



The following are generating facilities owned by PGE:

Facility	Location	Net MW Capability (a) at December 31, 2007
Wholly-Owned:		
Hydro -		
Faraday	Clackamas River	46
North Fork	Clackamas River	58
Oak Grove	Clackamas River	44
River Mill	Clackamas River	25
Bull Run (b)	Sandy River	15
T.W. Sullivan	Willamette River	17
Natural Gas/Oil -		
Beaver	Clatskanie, Oregon	505
Coyote Springs	Boardman, Oregon	234
Port Westward	Clatskanie, Oregon	406
Wind -		
Biglow Canyon	Sherman County, Oregon	125
Jointly-Owned (c):		
Coal -		
Boardman (d)	Boardman, Oregon	380
Colstrip 3 and 4 (e)	Colstrip, Montana	296
Hydro -		
Pelton (f)	Deschutes River	73
Round Butte (f)	Deschutes River	225
Total		**2,449**

(a) Capability based on generation under normal operating conditions.
(b) Decommissioning planned for 2008.
(c) Net MW Capability reflects PGE's ownership share.
(d) PGE operates Boardman and has a 65% ownership interest.
(e) PPL Montana, LLC operates Colstrip 3 and 4; PGE has a 20% ownership interest.
(f) 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 Company's Sullivan plant operates under a FERC license that expires in 2035, while the Pelton and Round Butte plants operate under a license that expires in 2055.

The Company filed an application with the FERC in 2004 to relicense the Clackamas River hydroelectric projects. A settlement agreement, resolving most of the issues raised in the relicensing proceeding and providing for a 45-year license term, was signed by the thirty-three participating parties in March 2006 and was submitted to the FERC for review and approval. The settlement agreement 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. Pending approval of the new license, the project will operate under annual licenses issued by the FERC. It is expected that the FERC will issue a new license for the Clackamas River projects in 2009.

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. The Marmot Dam was removed in July 2007, reducing the project's capability to 15 MW, with removal of the Little Sandy Dam planned for 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 approximately $17 million in estimated decommissioning costs over a ten-year period ending in 2011. Total decommissioning costs increased to an estimated $24 million at December 31, 2007, with the incremental costs expected to be recovered in future prices charged to customers.

Transmission

PGE owns and/or 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 has contractual access to approximately 20% 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 closure of Trojan, PGE, in its 1993 general rate filing, sought OPUC approval to recover through rates future decommissioning costs and full recovery of, and a rate of return on, its Trojan investment. PGE's request was challenged and PGE requested from the OPUC a Declaratory Ruling (Docket DR 10) regarding recovery of the Trojan investment and decommissioning costs. In August 1993, the OPUC issued a Declaratory Ruling in PGE's favor, 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.

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 Order No. 07-157 (the Order) entered on April 19, 2007, the OPUC denied PGE's motion with the OPUC to Consolidate Phases and Re-Open the Record. In addition, the Order abated the Phase I proceeding pending a decision by the Oregon Court of Appeals of the 2003 Remand, and ordered that a second phase of the joint remand proceedings be immediately commenced to investigate the OPUC's delegated authority to engage in retroactive ratemaking. The Order further stated that parties not now participating in the joint remand proceedings will be allowed to intervene and participate in the second phase. Pursuant to the Order, final briefs were submitted on July 20, 2007 and oral argument was held on August 9, 2007, with a decision by the OPUC pending.

On October 10, 2007, the Oregon Court of Appeals issued an opinion that reversed a March 2002 OPUC Order (the 2002 Order) approving the 2000 settlement agreements and remanded the 2002 Order to the OPUC for reconsideration. The Oregon Court of Appeals also vacated the 2003 Remand.

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 plus interest for the Current Class and $70 million plus interest for the Former Class, from the inclusion of a return on investment of Trojan in the rates PGE charges its customers.

On April 28, 2004, the plaintiffs filed a Motion for Partial Summary Judgment and on July 30, 2004, PGE also moved for Summary Judgment in its favor on all of the Class Action Plaintiffs' claims. On December 14, 2004, the Judge granted the Plaintiffs' motion for Class Certification and Partial Summary Judgment and denied PGE's motion for Summary Judgment. 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.

On October 17, 2007, the plaintiffs in the class action suits filed a motion with the Marion County Circuit Court to lift the abatement ordered by the Circuit Court in October of 2006. A hearing on that motion is scheduled for April 2008. On January 14, 2008, the class action plaintiffs filed a motion asking the OPUC to issue an order on the OPUC remedial authority prior to addressing the other issues and the Utility Reform Project requested permission to address all issues it previously raised on appeal to the Circuit Court and on cross-appeal to the Court of Appeals in URP, et al. v. PUC, with an opportunity to present new evidence with full evidentiary hearings. On February 13, 2008, the OPUC issued an order denying this motion. In the order, the OPUC expressed its desire to avoid future piecemeal litigation by resolving all of these issues in one comprehensive order, including the issue of the OPUC's remedial authority. The OPUC further stated that it has come to the preliminary conclusion that the OPUC has refund authority under limited circumstances. The OPUC emphasized that this is a preliminary determination and stated that it has not yet determined whether it is necessary to exercise that authority in this case and that it cannot make such a determination until it has decided all phases of the proceedings. On February 22, 2008, the Administrative Law Judge issued a Ruling and Notice of Conference, which established the scope for further proceedings prior to issuance of the OPUC order. The ruling also includes notice of a conference scheduled for March 12, 2008 to establish a procedural schedule for the remainder of this phase of the proceeding.

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, with oral argument held on April 10, 2007.

On November 20, 2007, the Ninth Circuit affirmed the trial court's dismissal of the claims based on the filed rate doctrine. On January 15, 2008, the Ninth Circuit denied Wah Chang's petition for rehearing.

Puget Sound Energy, Inc. v. All Jurisdictional Sellers of Energy and/or Capacity at Wholesale Into Electric Energy and/or Capacity Markets in the Pacific Northwest, Including Parties to the Western System Power Pool Agreement, Federal Energy Regulatory Commission, Docket Nos. EL01-10-000, et seq. (Northwest Refund case)

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

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

The settlement between PGE and certain other parties in the California refund case in Docket No. EL00-95, *et seq*. (California Refund case), approved by the FERC on May 17, 2007, resolves all claims as between PGE and the California parties named in the settlement as to transactions in the Pacific Northwest during the settlement period, January 1, 2000 through June 21, 2001, but does not settle potential claims from other market participants relating to transactions in the Pacific Northwest.

In a separate action, on March 20, 2002, the California Attorney General filed a complaint (the Lockyer case) with the FERC against various sellers in the wholesale power market, alleging that the FERC's authorization of market-based rates violated the Federal Power Act (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. Petitions for rehearing at the Ninth Circuit and for U.S. Supreme Court review have been denied and the case has been remanded to the FERC.

On December 10, 2007, certain California parties filed with the FERC a Motion to hold the Lockyer case remand proceedings in abeyance until the court issues mandates in the California Refund case and Northwest Refund case. In their Motion, the California parties argue that all three cases include similar parties and similar issues, particularly the impact of alleged market manipulation in western energy markets during the 2000-2001 time period. They assert that these cases should be considered together by FERC and that they will file a motion to consolidate all three cases upon remand of the two that remain pending before the Ninth Circuit. The Company and other parties filed answers contesting the California parties' characterization of the three cases as inextricably linked and arguing that it is premature to discuss consolidation. Consolidation of the Lockyer case with the Northwest Refund case and the California Refund case could increase the Company's potential liability by extending the period for which other parties are requesting refunds back to May 1, 2000 or earlier.

General

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

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

None.

Part II

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

PGE common stock is traded on the New York Stock Exchange (NYSE) under the ticker symbol "POR". At February 15, 2008, there were 1,335 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 Share
2007 - Quarter	**High**	**Low**	
4	$28.45	$25.81	$0.235
3	28.51	26.43	0.235
2	31.03	26.65	0.235
1	29.81	25.70	0.225
2006 - Quarter			
4	$28.65	$24.12	$0.225
3	26.60	24.25	0.225
2	31.11	24.97	0.225
1*	-	-	-

* Prior to April 3, 2006, PGE's stock was not publicly traded.

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.

As required by Section 303A.12 of the NYSE Listed Company Manual, the Chief Executive Officer of the Company certified to the NYSE on May 3, 2007 that she was not aware of any violation by the Company of the NYSE's corporate governance listing standards.

Item 6. Selected Financial Data

Statement of Income Data:

	For the Years Ended December 31,				
	2007	**2006**	**2005**	**2004**	**2003**
	(In millions, except per share amounts)				
Revenues (a)	$1,743	$1,520	$1,446	$1,454	$1,752
Income from operations	198	121	126	150	124
Net income	145	71	64	92	60
Earnings per share - basic and diluted	2.33	1.14	1.02	1.48	0.94
Dividends declared per common share	0.93	0.675	*	*	*

Balance Sheet Data:

	December 31,				
	2007	**2006**	**2005**	**2004**	**2003**
	(In millions)				
Total assets	$4,108	$3,767	$3,638	$3,403	$3,372
Long-term debt (b)	1,313	1,003	890	922	983

(a) On October 1, 2003, PGE adopted 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' as Defined in Issue No. 02-3*, which 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 Revenues and Purchased power and fuel expense. Amounts for periods prior to October 1, 2003 were not reclassified. Accordingly, Revenues for 2003 are not comparable to 2004 through 2007.

(b) Includes preferred stock subject to mandatory redemption requirements, in 2006 and earlier.

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

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

Information Regarding Forward-Looking Statements

The information in this report includes statements that are forward-looking within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements relate to expectations, beliefs, plans, objectives for future operations, assumptions, business prospects, the outcome of litigation and regulatory proceedings, future capital expenditures, market conditions, future events or performance and other matters. Words or phrases such as "anticipates," "believes," "should," "estimates," "expects," "intends," "plans," "predicts," "projects," "will likely result," "will continue," or similar expressions 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 any assumptions and other factors and matters referred to specifically in connection with such forward-looking statements, factors that could cause actual results or outcomes for PGE to differ materially from those discussed in forward-looking statements include:

- governmental policies and regulatory audits, investigations, and actions, including those of the FERC and OPUC with respect to allowed rates of return, financings, electricity pricing and price structures, acquisition and disposal of assets and facilities, operation and construction of plant facilities, transmission of electricity, recovery of NVPC and other capital investments, and current or prospective wholesale and retail competition;
- the outcome of legal and regulatory proceedings and issues, including the Trojan Investment Recovery and the Pacific Northwest Refunds proceedings, described in Note 14, Contingencies, in the Notes to Consolidated Financial Statements;
- unseasonable weather and other natural phenomena, which, in addition to affecting PGE's customers' demand for power, could have a serious impact on PGE's ability and cost to procure adequate supplies of fuel or power to serve its customers;
- operational factors affecting PGE's power generation facilities including outages, unplanned forced outages, hydro conditions, wind conditions, and disruption of fuel supply;
- wholesale energy prices (including the effect of FERC price controls) and their impact on the availability and price of wholesale power in the western United States;
- residential, commercial, and industrial growth and demographic patterns in PGE's service territory;
- future laws, regulations, and proceedings 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 future operations of the Company's thermal generating plants;
- capital market conditions, including interest rate fluctuations, and changes in PGE's credit ratings, which could have an impact on the cost of capital and the ability of PGE to access the

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

- the effectiveness of PGE's risk management policies and procedures and the creditworthiness of customers and counterparties;
- the failure to complete major generating plants on schedule and within budget;
- the effects of Oregon law related to utility rate treatment of income taxes (SB 408), which may result in earnings volatility and adverse effects on results of operations;
- changes in, and compliance with, environmental and endangered species laws and policies;
- the effects of global warming or climate change, including changes in the environment that may affect energy costs or consumption and changes in laws or regulations related to greenhouse gas emissions that may increase the Company's costs or affect its operations;
- new federal, state, and local laws that could have adverse effects on operating results;
- employee workforce factors, including aging, potential strikes, work stoppages, and the loss of key executives;
- general political, economic, and financial market conditions;
- the outcome of efforts to relicense the Company's hydroelectric projects, as required by the FERC;
- natural disasters and other natural risks, such as earthquake, flood, drought, lightning, wind, and fire;
- acts of war or terrorism; and
- financial or regulatory accounting principles or policies imposed by governing bodies.

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

Overview

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

The Company's revenues and income from operations are subject to fluctuations during the year due to the impacts of seasonal weather conditions on demand for electricity, price changes, customer usage patterns, and the availability and price of purchased power and fuel. PGE is a winter peaking utility that typically experiences its highest retail energy sales during the winter heating season, with a slightly lower peak in the summer that generally results from air conditioning demand.

Customers - As of December 31, 2007, the Company served approximately 804,000 retail customers, a 1.4% increase from the end of 2006. The number of residential and commercial customers both increased during 2007, with total retail energy deliveries up 1.0% for the year. This growth was the result of continued economic expansion, as Oregon's non-farm employment (seasonally adjusted) grew 1.4% in 2007 and the state's 5.3% unemployment rate (seasonally adjusted) was down slightly from 2006.

The Company expects weather adjusted retail loads to increase 1.9% in 2008, with higher commercial demand and increased deliveries to industrial customers, including new solar panel manufacturers, expected to more than offset slower growth in the housing market and lower residential use resulting from conservation and energy efficiency efforts. Customer increases and demand growth will require continued investment in generation, transmission and distribution facilities to meet increased energy requirements.

PGE continues its focus on customer service and recognizes the importance of reliability, restoration response, safety, and reasonable prices in maintaining overall customer satisfaction. As the Company effectively maintains and improves its transmission, distribution, and customer service systems, it continues to place a top priority on meeting regulatory standards for safety and constantly strives to exceed service quality standards related to outage frequency and duration. The Company continues to rank high in surveys of customer satisfaction.

PGE is currently engaged in three major efforts that are expected to benefit customers. First, the Company has a customer focus initiative that seeks to meet rising customer expectations for service and reliability. Second, the Company has signed contracts with vendors for the purchase and installation of an Advanced Metering Infrastructure (AMI) system. Subject to Board of Directors and regulatory approvals, PGE will deploy AMI for residential and commercial customers between 2008 and 2010, with the expectation of achieving operational savings through increased efficiencies while also providing new services for customers. Third, the Company has undertaken an initiative to improve its ability to serve increasing numbers of customers who do business with PGE through the internet.

PGE periodically evaluates the need to change its overall general retail electric price structure to sufficiently cover its operating costs and provide a reasonable rate of return. PGE plans to file new tariffs with the OPUC on February 27, 2008, based on a forecasted 2009 test year, seeking an increase in electricity prices effective January 1, 2009. The proposed 8.9% increase in prices is a result of increased generation costs based on higher natural gas and coal prices; increased purchased power costs; and higher general (non-power) costs, including the rising cost of materials and supplies, government compliance, hydro relicensing improvements, and labor and healthcare benefits. The revenue requirements include a return on common equity of 10.75%, based on an expected capital structure of 50% equity and 50% debt, and an overall weighted average cost of capital of 8.66%. Review of PGE's filing by the OPUC, including a detailed analysis of the Company's projected costs and proposed price structure, is expected to take nine to ten months and will include input from stakeholders.

In May 2007, Residential Exchange Program (REP) payments to the region's investor-owned utilities, including PGE, were suspended as a result of a decision by the U.S. Ninth Circuit Court of Appeals. This program, administered by the Bonneville Power Administration (BPA), provides residential and small farm customers with the benefits of federal power. The removal of exchange program credits from PGE customers' bills has resulted in an approximate 14% average price increase for the Company's residential and small farm customers. In February 2008, the BPA issued its initial proposal to re-establish REP payments to investor-owned utilities. For further information, see "Results of Operations" in this Item 7.

Power Supply - PGE utilizes its own generating resources, along with wholesale market purchases, to meet the energy and capacity needs of its customers. In June 2007, the Company added the 406 MW capacity Port Westward plant to its base of generating resources, reducing its dependence on the wholesale energy market. With the completion of the 125 MW Phase I of Biglow Canyon in late 2007, the Company has a more diverse generation portfolio powered by coal, natural gas, hydro and wind and has further reduced its dependence on purchased power. In addition, PGE has implemented a generation excellence program aimed at ensuring cost-effective and reliable plant operations.

PGE supplements its own generation with short- and long-term wholesale contracts as needed to meet its retail load requirements and provide the most economic mix on a variable cost basis. 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 regions of the United States. Prices of purchased power, coal, and natural gas trended upward during 2007, due in part to the effect of higher crude oil prices, with the increased coal and natural gas prices resulting in higher overall generation costs.

PGE's 2007 IRP, filed with the OPUC in June 2007, describes the Company's energy and capacity supply strategy to meet the long-term electric energy needs of its customers, with emphasis on supply reliability and price stability. The result of a planning process utilizing input from various stakeholders, the IRP includes additional renewable and demand-side resources, energy efficiency measures, demand-side resources, power purchase agreements of varying terms, and the acquisition of additional peaking capacity. Once the OPUC has officially acknowledged the plan, the Company will issue Requests for Proposals to acquire sufficient resources, including power contracts and asset acquisitions, to meet the future energy and capacity needs of its customers, as outlined in the plan. For further information, see "Integrated Resource Plan" under "Power and Fuel Supply" included in Item 1. - "Business."

New Renewable Energy Standards adopted by the 2007 Oregon legislature require that PGE and other large electricity providers in Oregon serve at least 25% of their retail load within the state from renewable resources by the year 2025, with interim requirements of 5% by 2011, 15% by 2015, and 20% by 2020. Biglow Canyon, which is expected to have a total installed capacity of 400 to 450 MW when all three phases are completed by the end of 2010, represents a significant step toward the Company's achievement of these goals.

Legal, Regulatory, and Environmental Matters - PGE is a party in several legal and regulatory proceedings that could have a material impact on the Company's results of operations and cash flows for future periods, including:

- challenges, appeals and reviews on the issue of the OPUC's authority to grant a return on the Company's remaining investment in its closed Trojan plant during the period it ordered PGE to amortize the investment, which the OPUC set in a 1995 general rate order;
- claims for refunds related to wholesale energy sales in the Pacific Northwest during 2000 - 2001; and
- an OPUC order that approved a deferred accounting application that could result in customer refunds of a portion of state and federal income taxes related to the three-month period prior to the January 1, 2006 effective date of the automatic adjustment clause of SB 408.

For further information regarding these and other matters, see Note 14, Contingencies, in the Notes to Consolidated Financial Statements.

PGE is subject to state and federal environmental laws and regulations that establish air quality standards and regulate allowed emissions from thermal generating plants. Such laws and regulations, as well as federal regional haze rules that establish goals to protect visibility and remedy existing impairments resulting from man-made pollution, may affect the Company's operations. While PGE anticipates that it will be able to comply with these restrictions and those imposed under the Clean Air Mercury Rule, such rules will require added costs for additional emission control equipment. In November 2007, the Company submitted to the Oregon DEQ its BART plan for implementing controls to meet the requirements. Final approval of the plan is expected to occur in the second half of 2009. For further information, see "Air Quality Standards" within "Capital Requirements" of the Capital Resources and Liquidity section of this Item 7.

The Company has begun construction of a Selective Water Withdrawal structure at its Pelton Round Butte Hydroelectric Project in an effort to restore fish passage on the upper Deschutes River. During 2007, decommissioning of the Bull Run system began with the removal of the Marmot Dam, allowing fish passage on the Sandy River.

In addition, increasing local, national and international concerns regarding global warming and climate change may result in future laws or regulations that require additional pollution control equipment or significant emissions fees or taxes. For further information regarding estimated future capital expenditures related to emission control laws and regulations, see "Capital Requirements" in "Capital Resources and Liquidity" in this Item 7.

Financing - PGE maintains adequate liquidity through both its $400 million credit facility and access to the commercial paper market. The Company issued a total of $375 million of First Mortgage Bonds in 2007 to help provide sufficient liquidity to fund ongoing operations and construction projects. Increased capital expenditures expected over the next several years include those related to Phases II and III of Biglow Canyon, hydro relicensing, the AMI project, and requirements of environmental regulations. The Company's ability to execute its capital investment plan will depend on continued strength in the economy and access to capital markets. In anticipation of additional capital needs, the Company recently received authorization from the FERC to increase its short-term borrowing to a total of $550 million and has received approval from the OPUC to issue an additional $250 million of First Mortgage Bonds.

PGE strives to maintain a common equity ratio (common equity to total consolidated capitalization, including current debt maturities) 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, 2007 was 50%.

For a discussion of new accounting standards that have been issued but not yet adopted by the Company, see "New Accounting Standards" within Note 1, Summary of Significant Accounting Policies, in the Notes to Consolidated Financial Statements.

Results of Operations

See Consolidated Statements of Income in Item 8. - "Financial Statements and Supplementary Data," for Operating expense detail. The following tables contain certain financial and operating information for the periods presented:

	Years Ended December 31,		
	2007	**2006**	**2005**
Revenues (in millions):			
Retail sales:			
Residential	$ 716	$ 628	$ 593
Commercial	593	547	505
Industrial	159	206	178
Total retail sales	1,468	1,381	1,276
Direct access customers:			
Commercial	-	(6)	1
Industrial	(12)	(6)	-
Total tariff revenues	1,456	1,369	1,277
Regional Power Act credits	42	35	31
Provision for collection (refund) - SB 408	18	(40)	-
Accrued revenue	-	3	(3)
Total retail revenues	1,516	1,367	1,305
Wholesale revenues	201	135	116
Other operating revenues	26	18	25
Total revenues	$ 1,743	$ 1,520	$ 1,446

	Years Ended December 31,		
	2007	2006	2005
Energy sold and delivered - MWhs (in thousands):			
Retail energy sales:			
Residential	7,688	7,573	7,323
Commercial	7,289	7,319	7,069
Industrial	2,485	3,541	3,148
Total retail energy sales	17,462	18,433	17,540
Delivery to direct access customers:			
Commercial	492	430	400
Industrial	1,673	569	814
Total retail energy deliveries	19,627	19,432	18,754
Wholesale sales	4,042	3,312	2,094
Trading activities	-	-	815
Total energy sold and delivered	23,669	22,744	21,663

	As of December 31,		
	2007	2006	2005
Retail customers:			
Residential	706,444	696,779	685,568
Commercial	97,088	95,734	94,012
Industrial	256	259	257
Total retail customers	803,788	792,772	779,837

2007 Compared to 2006

PGE's net income was $145 million, or $2.33 per diluted share, for the year ended December 31, 2007 compared to $71 million, or $1.14 per diluted share, for the year ended December 31, 2006. The improved results were primarily attributable to increased energy deliveries, increased generation from the return of Boardman to full operation, and the addition of Port Westward. Results for 2006 included a $32 million after-tax impact of incremental power costs required to replace the output of Boardman during its extended repair outage. Results for 2007 include a positive $16 million after-tax impact of the deferral of a portion of the Boardman replacement power costs (including accrued interest) for potential future recovery, as approved by the OPUC.

Also contributing to the increase in earnings was a $35 million after-tax impact from SB 408, with an estimated collection from customers recorded in 2007 compared to a refund recorded in 2006. This positive impact in 2007 reflects in part the so-called "double whammy" effect of the law that results in unusual outcomes in certain situations. As the provisions of SB 408 apply to PGE, if the Company records higher operating income as compared to its latest rate case, customers would be surcharged for the increase in income taxes, further increasing earnings. Conversely, if the Company records lower operating income as compared to its latest rate case, customers would receive refunds for the decrease in income taxes, further decreasing earnings. For further information, see Note 15, Utility Rate Treatment of Income Taxes, in the Notes to Consolidated Financial Statements.

Total revenues in 2007 increased $223 million, or 15%, from 2006 as a result of the following factors:

- Total retail revenues increased $149 million, or 11%, due primarily to:
    - Price increases related to higher power and fuel costs and cost recovery of Port Westward, resulting in an approximate 6.4% increase in annual revenues;
    - A $58 million increase related to SB 408, with $18 million in collections recorded in 2007 (consisting of $15 million for the 2007 reporting year and $3 million related to the 2006 reporting year) and a $40 million refund recorded in 2006;
    - A 1% increase in total retail energy deliveries, primarily from an approximate 11,500 increase in the average number of customers served in 2007; and
    - Price increases resulting from changes under the Residential Exchange Program due to the discontinuance of subscription power benefits (fully offset by increased purchased power costs) and suspension of cash payments in May 2007.

  Lower energy sales to industrial customers resulted from a greater portion of industrial customers choosing direct access and purchasing their energy requirements from an Electricity Service Supplier (ESS). Reduced revenues from these customers reflect the lower energy sales as well as "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.

  On a weather adjusted basis, retail energy deliveries to PGE and ESS customers increased 1.1% in 2007, with deliveries to residential, commercial, and industrial customers increasing by 0.7%, 1.0%, and 2.2%, respectively. Increased residential sales resulted primarily from an increase of 10,000 in the average number of customers served during the year. Higher commercial and industrial sales resulted from a 1,500 increase in the average number of customers served. These increases were partially offset by a slowing economy and conservation efforts. PGE forecasts an approximate 1.9% increase in total weather adjusted energy deliveries to PGE and ESS customers in 2008.

- Wholesale revenues increased $66 million, or 49%, from 2006 due to:
    - A $36 million, or 22%, increase in energy sales; and
    - A $30 million, or 22%, increase in average sales price, related to higher natural gas prices and lower regional hydro availability.
- Other operating revenues increased $8 million, or 44%, primarily as the result of increased gains from the sale of natural gas in excess of generating plant requirements.

The following price adjustments, as approved by the OPUC, became effective on January 1, 2008:

- Biglow Canyon - An approximate 0.6% average price increase for cost recovery of Phase I of Biglow Canyon, which was commissioned in December 2007. The increase is net of savings resulting from a Strategic Investment Program that was executed with Sherman County, Oregon, where Biglow Canyon is located, that provides for property tax relief for a period of fifteen years, which will be passed along to customers; and
- Annual Power Cost Update Tariff - An approximate 0.3% price decrease for changes in forecasted power and fuel costs. The approved tariff establishes a new baseline NVPC for purposes of the PCAM calculation for 2008.

The above items, combined with other miscellaneous tariff changes totaling an approximate 0.5% increase, will result in an overall increase of approximately 0.8% in average prices for 2008.

Pending regulatory matters that could have an effect on customer prices and future revenues include the following:

- Residential Exchange Program (REP) - In May 2007, the BPA suspended REP payments to investor-owned utilities, including PGE, as a result of a decision by the U.S. Ninth Circuit Court of Appeals. The removal of exchange program credits from PGE customers' bills has resulted in an approximate 14% average price increase for the Company's residential and small farm customers. In February 2008, the BPA issued its initial proposal to re-establish REP payments to investor-owned utilities. Payments would begin in late 2008 and include $210 million ($46 million to be credited to PGE customers) related to BPA's 2009 fiscal year, which begins October 1, 2008.

  BPA has also determined that actual REP payments made from 2002 through May 2007 under certain settlement agreements exceeded those which should have been made under terms of traditional REP agreements covering the period 2002 through 2011. In its initial proposal BPA stated that such agreements would have utilized a calculation method that would have resulted in lower payments than those actually made by BPA. The BPA proposal includes recovery of $620 million of such overpayment ($64 million from PGE customers) over the period of 2009 through 2028. The recovery will reduce future REP payments to investor-owned utilities.

- "Energy Efficiency" Tariffs - On October 26, 2007, PGE filed proposed tariffs with the OPUC to implement demand-side programs outlined in the Company's 2007 IRP. The Company has requested to extend the proposed effective date of the tariffs from January 1, 2008 to June 1, 2008. If approved, the tariffs would provide an additional $14 million to the ETO and would result in certain incremental customer service expenses related to the achievement of energy savings targets.

- Boardman Deferral Amortization - On October 9, 2007, PGE filed a request with the OPUC to amortize the deferral of $26.4 million of replacement power costs, plus interest until the amortization period begins (accrued interest is $5.0 million as of December 31, 2007), associated with the outage of Boardman from November 18, 2005 through February 5, 2006. In its filing, the Company proposed that the amortization be offset with certain credits due to customers, with no price impact anticipated. PGE's request is subject to both a prudency review with respect to the outage and to a regulated earnings test.

- AMI - PGE is seeking OPUC approval of a new tariff that includes an approximate $13 million increase in annual revenue requirements to recover the cost of the AMI project, including recovery of the undepreciated cost of existing meters. The proposed tariff would run for approximately two and a half years, coinciding with the period over which PGE completes systems acceptance testing and installation of the new meters, expected to begin in mid-2008, subject to OPUC approval.

- Customer refunds (SB 408) - PGE filed its report on October 15, 2007 with the OPUC reflecting the amount of taxes paid by the Company for the 2006 reporting year, as well as the amount of taxes authorized to be collected in rates. The report is being reviewed as part of a formal process, with the OPUC expected to issue an order in April 2008. The Company has reached agreement with OPUC Staff and certain interveners that the appropriate refund due customers is $37.2 million plus accrued interest, based on the OPUC's administrative rules that govern the calculation of the refund amount. Under OPUC rules, refunds to customers for the 2006 reporting year will begin on June 1, 2008.

- PCAM - In 2007, PGE recorded a regulatory liability of $16.5 million, including accrued interest, under the PCAM for potential refund to customers. The amount is subject to review by the OPUC and is expected to be included in future prices over a period that has yet to be determined.
- In December 2007, the OPUC issued an order that provides an automatic adjustment clause for renewable resources that are expected to be placed in service in the current year. PGE would need to file by April 1 of each year proposed prices to be effective January 1 of the following year. Costs of the eligible resources would earn a return based on the latest authorized cost of capital until added to rate base in PGE's next general rate case filing.

Purchased power and fuel expenses for 2007 increased $116 million, or 15%, from 2006. The following table indicates PGE's total system load (including both retail and wholesale) for the last two years.

	Megawatt-Hours (in thousands)	
	2007	**2006**
Generation	10,403	7,209
Term purchases	10,898	13,582
Spot purchases	1,379	2,229
Total system load	22,680	23,020

The average variable power cost of the above total system loads was $39.19 per MWh in 2007 and $33.65 per MWh in 2006. Averages exclude the effect of amounts related to regulatory power cost deferrals, unrealized gains on derivative instruments, and wholesale credit provisions.

The increase in Purchased power and fuel expense was due primarily to the following factors:

- A $101 million increase related to increased thermal generation, which displaced higher-cost electricity purchases in the wholesale market. Increased generation was related primarily to operation of PGE's new Port Westward plant during the last half of 2007 and full-year operation of Boardman, which was closed for repairs in the first half of 2006;
- A $95 million increase related to settled natural gas swap agreements entered into in conjunction with PGE's management of its net power costs. These agreements are among those financial instruments in the Company's diversified power supply portfolio used to manage market risk, with activities reflected in Wholesale revenues, Purchased power and fuel expense, and Other operating revenues. See "Commodity Price Risk" in Item 7A. - "Quantitative and Qualitative Disclosures About Market Risk," for further information;
- A 12% increase in the average cost of purchased power, resulting in an approximate $58 million increase to expense;
- $16 million that has been recorded for future refund to customers under the PCAM, based upon the difference between NVPC as determined by the PCAM and those forecasted and included in retail prices. PGE's NVPC as determined by the PCAM for 2007 was less than the established baseline by $29.4 million. Under the PCAM, 90% of the difference between the $29.4 million and the deadband threshold of $11.7 is to be refunded to customers;
- Unrealized gains on derivative activities of $5 million in 2006. Results of these activities are fully deferred in 2007 as a result of the OPUC's approval of the PCAM; and
- Discontinuance of subscription power benefits under the Residential Exchange Program (fully offset by increased revenues, with no net income effect).

Partially offsetting the above increases were:

- A 22% decrease in electricity purchases, related primarily to an increase in lower cost thermal generation, resulting in an approximate $136 million reduction to 2007 expense;
- An increase of $14.4 million in the deferral, for future recovery, of excess Boardman power costs (approved by the OPUC in February 2007), resulting in a reduction to 2007 expense; and
- A $5 million reduction in the Company's wholesale credit reserve, related primarily to the settlement with certain California parties involving wholesale energy transactions in 2000-2001, resulting in a reduction to 2007 expense.

Generation activities - In 2007, PGE generated 56% of its retail load requirement compared to 37% in 2006. Short- and long-term purchases were utilized to meet the remaining load. The Company met 46% of its retail load requirement from thermal generation in 2007 compared to 27% in 2006. PGE-owned hydro generation met 10% of PGE's retail load requirement in both 2007 and 2006.

The addition of Port Westward in June 2007 and the full-year operation of Boardman combined to increase thermal production by 65% in 2007, resulting in reduced reliance on higher cost purchases in the wholesale market.

Partially offsetting the increase in thermal production was a 10% decrease in Company-owned hydro production, resulting from lower stream flows. PGE has long-term agreements to purchase power generated from hydro facilities on the mid-Columbia River. Energy received under these agreements increased 3% in 2007.

Current forecasts indicate that regional hydro conditions in 2008 will be near normal levels. Volumetric water supply forecasts for the Pacific Northwest region, prepared by the Northwest River Forecast Center in conjunction with the Natural Resources Conservation Service and other cooperating agencies as of February 14, 2008 indicate the April-to-September 2008 runoff forecast compared to the actual runoffs for 2007 and 2006, as follows:

Location	2008 Forecast	2007 Actual	2006 Actual
Columbia River at The Dalles, Oregon	102%	97%	107%
Mid-Columbia River at Grand Coulee, Washington	101%	102%	101%
Clackamas River	126%	100%	92%
Deschutes River	106%	91%	100%

Production, distribution, administrative and other expenses increased $30 million, or 10%, in 2007 compared to 2006, due to the following factors:

- A $19 million increase in employee benefits (including incentive compensation and medical costs) and customer support expenses;
- Operating costs at the new Port Westward plant of $6 million;
- A $3 million increase in labor costs; and
- A $2 million increase related to maintenance activities at Boardman and Colstrip.

Depreciation and amortization expenses decreased $38 million, or 17%, from 2006 due primarily to the net effect of the following factors:

- A $27 million decrease resulting primarily from reductions in depreciation rates for utility plant assets and the authorized recovery of Trojan decommissioning costs, both of which became effective in January 2007 pursuant to the OPUC order in PGE's general rate case;

- A $13 million decrease in the amortization of regulatory assets (fully offset within Income from operations due to a corresponding decrease in Revenues);
- A reduction in the deferral of certain tax credits for future ratemaking treatment, resulting in an approximate $2 million decrease to expense; and
- A $7 million increase related to the new Port Westward plant, Biglow Canyon, and other capital additions during 2007.

Taxes other than income taxes increased $5 million, or 7%, in 2007 primarily due to:

- A $3 million increase in city franchise fees resulting from customer price increases during the year; and
- A $2 million increase in property taxes resulting from higher assessed property values.

Income taxes increased $33 million, or 87%, in 2007, due primarily to higher taxable income for the year.

Other income increased $2 million, or 11%, in 2007 due primarily to the net effect of the following factors:

- A $5 million interest income accrual (retroactive to January 2006) on $26.4 million of excess power costs associated with Boardman's repair outage, which has been deferred for future recovery, as approved by the OPUC;
- A 2006 expense of $5 million related to a loss provision on a non-utility asset and the write-off of certain software costs;
- A $1 million increase in interest income related to future customer collections for the 2007 tax year, under the provisions of SB 408;
- A $4 million increase in non-utility income taxes associated with the above items; and
- A $3 million decrease in income from non-qualified benefit plan trust assets.

Interest expense increased $5 million, or 7%, in 2007, primarily due to a higher level of outstanding long-term debt resulting from the issuance of additional First Mortgage Bonds during the year.

2006 Compared to 2005

PGE's net income was $71 million, or $1.14 per diluted share, for the year ended December 31, 2006 compared to $64 million, or $1.02 per diluted share, for the year ended December 31, 2005. The improved results were primarily attributable to higher energy sales, resulting from both an increase in customers served and weather conditions, and increased hydro availability, resulting from improved stream flows. Results for 2006 also included a $26 million after-tax reserve for a potential refund obligation to customers, reflecting the Company's estimate of the impact of SB 408. In addition, 2006 results reflect a $4 million after-tax decrease in earnings related to the higher cost of incremental replacement power during the extended, unplanned repair outage at Boardman. Results for 2005 include a $6 million after-tax provision related to the refund to customers of previously collected local income taxes.

Total revenues increased $74 million, or 5%, in 2006 from 2005 as a result of the following factors:

- Total retail revenues increased $62 million, or 5%, due to the net effect of the following factors:
    - A 3.7% average price increase related to higher power and fuel costs;

- A 3.6% increase in total retail energy deliveries, resulting primarily from an approximate 13,500 increase in the average number of customers served during the year;
- A $40 million decrease related to SB 408, with an estimated customer refund reserve recorded in 2006. For further information, see Note 15, Utility Rate Treatment of Income Taxes, in the Notes to Consolidated Financial Statements;
- A $26 million reduction in the collection of regulatory assets (fully offset in Income from operations due to a corresponding decrease in Depreciation and amortization expense); and
- A $13 million decrease related to "transition adjustment" credits provided to direct access customers, reflecting the difference between the cost and market value of PGE's power supply portfolio, as provided by Oregon's electricity restructuring law.

Weather adjusted retail energy deliveries to PGE customers, including those purchasing energy from an ESS, 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.

- Wholesale revenues increased $19 million, or 16%, primarily due to the net effect of the following factors:
  - A 58% increase in energy sales; and
  - A 26% reduction in average sales price, resulting from increased regional hydro availability.
- Other operating revenues decreased $7 million, or 28%, as the result of 2006 losses from the sale of natural gas in excess of generating plant requirements.

Purchased power and fuel expenses increased $92 million, or 14%, in 2006 from 2005 as a result of the following factors:

- Higher power purchases required to meet a 10% increase in total system load requirement;
- An increase in the cost of replacing coal-fired generation at Boardman; and
- Higher wholesale prices.

The following table indicates PGE's total system load (including both retail and wholesale) for the years 2006 and 2005.

	Megawatt-Hours (in thousands)	
	2006	**2005**
Generation	7,209	7,821
Term purchases	13,582	11,705
Spot purchases	2,229	1,361
Total system load	23,020	20,887

The average variable power cost of the above total system loads was $33.65 per MWh in 2006 and 31.34 per MWh in 2005. Averages exclude the effect of amounts related to regulatory power cost deferrals, unrealized gains on derivative instruments, and wholesale credit provisions.

Generation activities - In 2006, PGE generated 37% of its retail load requirement compared to 42% in 2005. Short- and long-term purchases were utilized to meet the remaining load. The Company met 27% of its retail load requirement from thermal generation and 10% from hydro generation in 2006 compared to 34% and 8%, respectively, in 2005.

A 17% reduction in thermal production, related primarily to Boardman's outage from late October 2005 through June 2006, resulted in increased reliance on higher cost purchases in the wholesale market.

Partially offsetting the decrease in thermal production was a 28% increase in Company-owned hydro production, resulting from increased stream flows. Energy received under long-term agreements to purchase power from hydro facilities on the mid-Columbia River increased 13% in 2006 compared to 2005.

Production, distribution, administrative and other expenses increased $8 million, or 3%, in 2006 compared to 2005 primarily due to increased expenses related to maintenance and repair activities at PGE's thermal generating plants, storm-related service restoration costs, and increased tree trimming costs. Such increases were partially offset by reduced administrative and other expenses, related primarily to the settlement of certain asserted claims in 2005.

Depreciation and amortization expenses decreased $14 million, or 6%, in 2006 compared to 2005 due primarily to the net effect of the following factors:

- A $26 million decrease in amortization of regulatory assets (fully offset in Income from operations due to a corresponding decrease in Revenues);
- A $6 million increase in depreciation of transmission and distribution plant, due to higher plant balances in 2006;
- A $2 million increase in the deferral of certain tax credits;
- A $2 million increase in amortization of computer software; and
- A $2 million increase in other amortization, including amortization of hydro relicensing costs.

Income taxes decreased $8 million, or 17%, primarily due to lower taxable income and a reduction in state income taxes resulting from apportionment rule changes.

Other income increased $13 million in 2006 compared to 2005 due to the net effect of the following factors:

- A $10 million reserve established in 2005 for the refund to Multnomah County customers of previously collected income taxes;
- An $8 million increase in the allowance for equity funds used during construction, related primarily related to Port Westward; and
- A $3 million decrease in interest income on regulatory assets, due to declining balances as amounts are recovered from customers.

Interest expense increased $1 million, or 1%, in 2006 compared to 2005, primarily due to a higher level of outstanding long-term debt resulting from the issuance of additional First Mortgage Bonds during 2006.

Capital Resources and Liquidity

<u>Capital Requirements</u>

The following table presents PGE's projected primary cash requirements, excluding AFDC, for the years indicated (in millions):

<table>
<tr><th></th><th>2008</th><th>2009</th><th>2010</th><th>2011</th><th>2012</th></tr>
<tr><td>Ongoing capital expenditures (a)</td><td>$229</td><td>$ 210 - 230</td><td>$ 215 - 235</td><td>$ 240 - 260</td><td>$ 225 - 245</td></tr>
<tr><td>Biglow Canyon - Phases II and III (b)</td><td>121</td><td colspan="3">$ 500 - 600</td><td></td></tr>
<tr><td>Hydro relicensing</td><td>55</td><td colspan="4">$ 105 - 115</td></tr>
<tr><td>Advanced Metering Infrastructure (c)</td><td>23</td><td colspan="3">$ 100 - 110</td><td></td></tr>
<tr><td>Boardman emissions controls (d)</td><td>-</td><td colspan="4">$ 230 - 240</td></tr>
<tr><td>Total capital expenditures</td><td>$428</td><td></td><td></td><td></td><td></td></tr>
<tr><td>Long-term debt maturities</td><td>$ -</td><td>-</td><td>$ 186</td><td>-</td><td>$ 100</td></tr>
</table>

(a) Upgrades to transmission, distribution and existing generation, as well as new customer connections.
(b) Phases II and III timing subject to turbine availability and project economics.
(c) Under review by OPUC.
(d) See Air Quality Standards, below, for further discussion of emission controls.

Biglow Canyon - In accordance with PGE's plan to acquire additional wind generation, as outlined in its IRP, the Company is proceeding with construction of Biglow Canyon, located in Sherman County, Oregon.

Phase I of the project, with an installed capacity of 125 MW and a cost of $255 million (including AFDC), has been completed. Phases II and III of the project are currently in the advanced planning stages. In the second quarter of 2007, PGE paid $17 million to a vendor towards wind turbines for Phases II and III. The payment is non-refundable if PGE and the vendor do not execute a definitive agreement after good faith efforts to negotiate and execute such an agreement within a specified time period. The payment will be returned to PGE if the vendor fails to negotiate the definitive agreement in good faith. The estimated total cost of Phases II and III is $700 million to $800 million, including approximately $50 million AFDC, with Phase II expected to be completed by the end of 2009 and Phase III expected to be completed by the end of 2010. The cost of the project could vary depending upon the fluctuations of foreign currencies against the U.S. dollar. Total installed capacity of all three phases is expected to be between 400 and 450 MW.

Hydro relicensing - As required under the 50-year license that the FERC issued to PGE in 2004 for its Pelton/Round Butte project on the Deschutes River, PGE began construction of a selective water withdrawal system in late 2007 in an effort to restore fish passage on the upper portion of the river. The system will collect juvenile salmon and steelhead, allowing them to bypass the dam when migrating to the Pacific Ocean, and will regulate downstream water temperature. Completion of the system, at a total cost of approximately $105 million to $110 million, is expected in 2009. PGE's portion of the costs is expected to be approximately $80 million, including AFDC.

Advanced Metering Infrastructure - PGE plans to install, subject to OPUC approval, over 800,000 new customer meters that would enable daily, two-way remote communications with the Company. AMI, at an estimated capital cost of $130 million to $135 million, is expected to provide improved services, operational efficiencies, and a reduction in future expenses.

Air Quality Standards - In accordance with new federal regional haze rules aimed at visibility impairment in several federally protected areas, the DEQ is conducting an assessment of emission sources pursuant to a 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 a BART Determination.

In addition, the federal government and the states in which PGE operates have adopted the following regulations concerning mercury emissions:

- In May 2005, the EPA adopted the Clean Air Mercury Rule 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."
- 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.
- In December 2006, the Oregon Environmental Quality Commission adopted the Utility Mercury Rule, which requires installation of mercury control technology at Boardman that would reduce the plant's mercury emissions by 90% by July 1, 2012.
- In February 2008, the U.S. Court of Appeals for the District of Columbia Circuit published a unanimous decision vacating both the EPA's rule delisting coal- and oil-fired electric generating units from regulation under § 112 of the CAA and the Clean Air Mercury Rule. The Oregon Utility Mercury Rule was not directly affected by this decision; however, it contains significant components of the federal Clean Air Mercury Rule and thus it is reasonably likely that amendments will be required if the District of Columbia Circuit decision is not overturned.

In response to the EPA's regional haze rules, the Company volunteered to participate in a DEQ pilot project to analyze information about air emissions from Boardman. An exemption modeling analysis for identified sources, which began in September 2006, has indicated that the Boardman and Beaver generating plants may cause or contribute to visibility impairment in several federally protected areas. In November 2007, the Company submitted a BART Determination to the DEQ for Boardman that stated the BART for Boardman is a combination of New Low NO_x Burners, Modified Over Fire Air System, SNCR, and Semi-dry Flue Gas Desulphurization, and that mercury emission regulations should be addressed through a Mercury Sorbent Injection System. The total cost for these controls is estimated to be in the range of $300 million to $400 million (100% of total costs). While the Company believes that these controls meet BART requirements, the regulatory agencies could require Selective Catalytic Reduction rather than SNCR, which would increase the total estimated cost to a range of $470 million to $620 million (100% of total costs). The Company has no commitments in place at this time and cautions that the cost estimates are preliminary and subject to change. Final approval of the plan is expected to occur in the second half of 2009.

As the regulatory requirements are clarified by the relevant agencies and the related costs more closely estimated, the Company will further evaluate the economic prudency of these expenditures. In doing so, the Company will also consider additional costs such as taxes, emission fees and other costs that may be imposed under any future laws related to climate change. Such additional costs, as well as the requirement to install Selective Catalytic Reduction controls, could require an investment in excess of what the plant can economically support.

The ultimate impact that the above regulatory requirements and air emission controls will have on future operations, costs, or generating capacity of the Company's thermal generating plants is not yet determinable. PGE will seek to recover its share of any associated costs through the ratemaking process.

On January 15, 2008, PGE received a notice of intent to sue from a coalition of environmental groups. The notice alleges violations of the Clean Air Act and the Oregon State Implementation Plan relating to the Boardman generation facility. The Company has not yet fully evaluated the claims referenced in the notice and cannot determine at this time its estimated exposure, if any. If the plaintiffs file their complaint and articulate their claims in greater detail, PGE will be better able to assess the likelihood, if any, that the claims will have a material adverse effect on the Company.

Transmission improvements - PGE and seven other utilities have initiated WECC Coordinated Planning and Technical Studies related to eight significant new high voltage transmission projects currently under consideration in the northwestern United States. The sponsors anticipate completion of the WECC Phase I Rating Studies by August 2008. The Southern Crossing Project, proposed by PGE, would expand the Company's transmission system across the Oregon Cascades with the construction of a new 500 kV transmission line. The project is designed to integrate existing Boardman and Coyote Springs generation resources, integrate up to 750 MW of proposed wind generation resources, and provide additional transmission capacity for future needs.

Liquidity

PGE's access to short-term debt markets provides sufficient liquidity to support current operating activities, including the purchase of electricity to meet load requirements and fuel for the Company's thermal generating plants. Long-term capital requirements are driven largely by expenditures for distribution, transmission, and generation facilities to support both new and existing customers, as well as debt retirement. PGE's liquidity and capital requirements can also be significantly affected by other working capital needs, including margin deposits related to wholesale trading activities, which can vary depending upon the Company's forward positions and the corresponding price curves.

PGE has performed an assessment of its investments held in trusts, which will be used to satisfy future obligations under the Company's pension and postretirement benefit plans and to satisfy future obligations to decommission its Trojan nuclear plant. The Company has determined that a decline in the fair value of its investments that may have subprime-related exposures would not be material.

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

	Years Ended December 31,		
	2007	**2006**	**2005**
Cash and cash equivalents, beginning of year	$ 12	$ 122	$ 204
Cash flows provided by (used in):			
Operating activities	344	106	372
Investing activities	(451)	(380)	(272)
Financing activities	168	164	(182)
Increase (decrease) in cash and cash equivalents	61	(110)	(82)
Cash and cash equivalents, end of year	$ 73	$ 12	$ 122

Cash Flows from Operating Activities - The $238 million increase in cash provided by operating activities in 2007 compared to 2006 was primarily attributable to:

- A $115 million decrease in margin deposits with certain wholesale customers, due in part to the Boardman repair outage in 2006;
- A $55 million decrease in income tax payments due to the payment of final taxes to PGE's former parent in 2006;

- A $33 million decrease in power purchases, due to the 2006 purchase of replacement power during Boardman's extended repair outage; and
- A $28 million cash payment received from the California Power Exchange resulting from a settlement related to wholesale energy transactions in 2000-2001.

A significant portion of cash provided by operations consists of the recovery in revenue requirements of non-cash charges for depreciation and amortization related to utility plant. The $38 million reduction of these charges in 2007 was due primarily to reduced depreciation rates and authorized recovery of Trojan decommissioning costs, as approved by the OPUC in PGE's general rate case. The Company estimates recovery of depreciation and amortization charges to be approximately $210 million in 2008. Combined with all other sources, cash provided by operations is estimated to be approximately $380 million during 2008.

Cash Flows from Investing Activities - Cash flows from investing activities consist of new construction and improvements to PGE's distribution, transmission, and generation facilities. The $71 million increase in cash used in investing activities was primarily attributable to the net effect of:

- A $169 million increase in expenditures for construction of Biglow Canyon;
- A $108 million reduction in construction costs for Port Westward due to the completion of construction in early 2007; and
- Increased expenditures related to the expansion of PGE's distribution system to support both new and existing customers within the Company's service territory.

The Company plans $428 million in total capital expenditures in 2008 related to Phases II and III of Biglow Canyon, hydro relicensing, ongoing capital expenditures and AMI.

Cash Flows from Financing Activities - Cash flows from financing activities provide supplemental cash for both operating and capital requirements. Cash provided by financing activities in 2007 was primarily attributable to the net effect of the following:

- Issuance of $375 million of First Mortgage Bonds, at a rate of approximately 5.8%, for general corporate purposes, capital expenditures and repayment of existing debt;
- Remarketing of $5.8 million of variable interest rate Port of Morrow Pollution Control Bonds;
- Repayment of $81 million in short-term debt;
- Payment of $58 million of common stock dividends;
- Redemption of $50 million of 7.15% First Mortgage Bonds at maturity;
- Redemption of remaining $16 million of 7.75% Series Cumulative Preferred Stock; and
- Early redemption of $5.1 million of 7 ⅛% Port of St. Helens Pollution Control Bonds due in 2014.

PGE has received approval from the FERC to increase its short-term borrowings up to a total of $550 million through February 6, 2010, and has received approval from the OPUC to issue an additional $250 million in long-term debt.

Dividends on Common Stock

The following table indicates common stock dividends declared in 2007:

Declaration Date	Record Date	Payment Date	Dividends Declared per Common Share
February 22, 2007	March 26, 2007	April 16, 2007	$0.225
May 2, 2007	June 25, 2007	July 16, 2007	0.235
August 2, 2007	September 25, 2007	October 15, 2007	0.235
October 25, 2007	December 26, 2007	January 15, 2008	0.235

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 is dependent 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. On February 20, 2008, the Board of Directors declared a dividend of $0.235 per share of common stock to stockholders of record on March 25, 2008, payable on or before April 15, 2008.

Debt and Equity Financings

PGE has a $400 million five-year revolving credit facility with a group of commercial and investment banks that supplements operating cash flow and provides a primary source of liquidity. The facility, which expires in 2012 and 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.

PGE's ability to secure sufficient long-term capital at a reasonable cost is determined by its financial performance and outlook, capital expenditure requirements, 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. Management believes that the availability of the credit facility and the expected ability to issue long-term debt and equity securities provide sufficient liquidity to meet the Company's anticipated capital and operating requirements. The Company anticipates issuing a total of approximately $300 million debt and $200 million equity in 2008 and 2009.

PGE's financial objectives include the balancing of debt and equity to maintain a low weighted average cost of capital while retaining sufficient flexibility to meet the Company's financial obligations. The Company attempts to maintain a common equity ratio (common equity to total consolidated capitalization, including current debt maturities) of approximately 50%. Achievement of this objective while sustaining sufficient cash flow is necessary to maintain acceptable credit ratings and allow access to long-term capital at attractive interest rates. PGE's common equity ratios were 50% and 53% at December 31, 2007 and December 31, 2006, respectively.

For further information regarding PGE's credit facility and debt financing activities, see Note 9, Credit Facility and Debt, in the Notes to Consolidated Financial Statements.

Credit Ratings and Debt Covenants

PGE's secured and unsecured debt is rated investment grade by Moody's Investors Service (Moody's) and Standard and Poor's (S&P). PGE's current credit ratings and outlook are as follows:

	Moody's	S&P
First Mortgage Bonds	Baa1	A
Senior unsecured debt	Baa2	BBB
Commercial paper	Prime-2	A-2
Outlook	Stable	Stable

Should Moody's and/or S&P reduce their credit rating on PGE's unsecured debt to below investment grade, the Company could be subject to requests by certain of its wholesale counterparties to post additional performance assurance collateral. On December 31, 2007, PGE had posted approximately $33 million of collateral, consisting of $28 million in cash and $5 million in letters of credit, none of which is affiliated with master netting agreements. Based on the Company's energy portfolio, estimates of current energy market prices, and the current level of collateral outstanding, as of

December 31, 2007, the approximate amount of additional collateral that could be requested upon a single agency downgrade to below investment grade is approximately $55 million and decreases to approximately $8 million by December 31, 2008. The approximate amount of additional collateral that could be requested upon a dual agency downgrade to below investment grade is approximately $83 million and decreases to approximately $8 million by December 31, 2008.

PGE's financing arrangements do not contain ratings triggers that would result in the acceleration of required interest and principal payments in the event of a ratings downgrade.

The issuance of additional First Mortgage Bonds requires that PGE meet earnings coverage and security provisions set forth in the Company's Amended and Restated Articles of Incorporation and the Indenture of Mortgage and Deed of Trust securing the bonds. PGE estimates that on December 31, 2007 it could issue up to approximately $601 million of First Mortgage Bonds under the most restrictive issuance test in the Indenture of Mortgage and Deed of Trust. Any issuances would 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 Indenture of Mortgage and Deed of Trust on the basis of property additions, bond credits, and/or deposits of cash.

PGE's credit facility contains customary covenants and credit provisions, including a requirement that limits consolidated indebtedness, as defined in the facility, to 65% of total capitalization. At December 31, 2007, the Company's consolidated indebtedness to total capitalization ratio, as calculated under the facility, was 50%.

Contractual Obligations and Commercial Commitments

The following indicates PGE's contractual obligations as of December 31, 2007 (in millions):

	Payments Due*						
	Total	**2008**	**2009**	**2010**	**2011**	**2012**	**There-after**
Long-term debt	$ 1,313	$ -	$ -	$ 186	$ -	$ 100	$1,027
Interest on long-term debt	1,490	81	81	70	67	67	1,124
Operating leases	257	8	7	7	7	8	220
Purchase obligations	171	94	54	11	10	1	1
Purchased power and fuel:							
Electricity purchases	1,341	350	161	75	74	63	618
Capacity contracts	191	23	23	23	23	23	76
Natural gas agreements	194	63	24	23	18	15	51
Public Utility Districts	86	8	9	7	7	5	50
Coal and transportation agreements	30	15	3	3	3	3	3
Total	$ 5,073	$ 642	$ 362	$ 405	$ 209	$ 285	$3,170

* Future interest on long-term debt is calculated based on the assumption that all debt remains outstanding until maturity. For debt instruments with variable rates, interest is calculated for all future periods using the rates in effect at December 31, 2007. Contributions to the Company's pension plan are estimated at zero for 2008 through 2012 and not determinable thereafter.

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 that would not adversely affect the tax exempt status of any outstanding debt.

For details of annual costs by project, including debt service, see Note 9, Commitments and Guarantees, in the Notes to Consolidated 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

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

Regulatory Accounting

As a regulated utility, PGE prepares its consolidated financial statements in accordance with the provisions of SFAS 71, *Accounting for the Effects of Certain Types of Regulation*. The application of SFAS 71 results in differences in the timing and recognition of certain revenues and expenses in comparison with businesses in other industries. Under the authority of the FERC and the OPUC, the Company has recorded certain regulatory assets and liabilities at December 31, 2007 in the amount of $304 million and $574 million, respectively, and regulatory assets and liabilities of $351 million and $523 million, respectively, at December 31, 2006. For further information, see Note 1, Summary of Significant Accounting Policies, in the Notes to Consolidated Financial Statements.

PGE is subject to jurisdiction of the OPUC, which reviews and approves the Company's retail rates, ensuring that they provide the Company an opportunity 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.

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

Asset Retirement Obligations

SFAS 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 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.

Contingencies

The Company has unresolved legal and regulatory issues for which there is inherent uncertainty with respect to the ultimate outcome of the respective matter. Contingencies are evaluated based on SFAS 5, *Accounting for Contingencies*, using the best information available. In accordance with SFAS 5, a material loss contingency is accrued and disclosed when it is probable that an asset has been impaired or a liability incurred and the amount of the loss can be reasonably estimated. If a range of probable loss is established, the minimum amount in the range is accrued, unless some other amount within the range appears to be a better estimate. If the probable loss cannot be reasonably estimated, no accrual is recorded, but the loss contingency is disclosed to the effect that it cannot be reasonably estimated. Material loss contingencies are disclosed when it is reasonably possible that an asset has been impaired or a liability incurred. Reserves established reflect management's assessment of inherent risks, credit worthiness, and complexities involved in the collection process. No assurance can be given for the ultimate outcome of any particular contingency.

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 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 a portion of the difference between each year's forecasted and actual NVPC. Effective December 2006, PGE began to apply SFAS 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.

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 can have a material impact on the valuation of the pension benefit plan obligation and net periodic pension cost.

PGE's pension discount rate is based on assumptions regarding rates of return on long-term high quality bonds. Assumptions regarding the expected rate of return on plan assets are based on historical and projected average rates of return for current asset classes in the plan investment portfolio. The expected rate of return reflects expected future returns for the portfolio, and was used in determining net periodic pension expense for the year. At December 31, 2007, the plan's assets were comprised of approximately 67% equity securities and 33% debt securities.

Changes in actuarial assumptions can also have a material effect on net periodic pension expense. A 0.25% reduction in the expected long-term rate of return on plan assets would have increased 2007 pension expense by approximately $1.2 million. A 0.25% reduction in the discount rate would have increased 2007 pension expense by approximately $1.5 million.

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 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. In early 2005, PGE discontinued its trading activities for non-retail purposes, with existing trading transactions settled by December 31, 2005. The Company uses purchased power contracts to supplement its thermal, hydroelectric, and wind 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 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 NYMEX 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. The risk factors include commodity prices for power and natural gas at various locations and do not include volumetric variability. Based on this methodology, the average, high, and low value at risk on the Company's energy portfolio in 2007 were $4.7 million, $7.6 million, and $1.6 million, respectively, and in 2006 were $5.7 million, $9.9 million, and $3.3 million, respectively.

PGE's energy portfolio activities are subject to regulation and related costs are recovered in retail prices approved by the OPUC. The timing differences between the recognition of gains and losses on certain derivative instruments and their realization and subsequent recovery in prices are deferred as regulatory assets and regulatory liabilities to reflect the effects of regulation under SFAS 71. As contracts are settled, these deferrals reverse. In PGE's value at risk methodology, no amounts are included for potential deferrals under SFAS 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 energy portfolio. Foreign currency risk is the risk of changes in value of pending financial obligations in foreign currencies that could occur prior to the settlement of the obligation due to a change in the value of that foreign currency in relation to the U.S. dollar. PGE monitors its exposure to fluctuations in the Canadian exchange rate with an appropriate hedging strategy.

At December 31, 2007, 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. PGE had no short-term debt outstanding at December 31, 2007.

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**	**2008**	**2009**	**2010**	**2011**	**2012**	**There-after**
First Mortgage Bonds	$ 957	$ 970	$-	$-	$ -	$-	$100	$ 870
Pollution Control Revenue Bonds *	198	195	-	-	37	-	-	158
Other	158	148	-	-	149	-	-	(1)
Total	$1,313	$1,313	$-	$-	$186	$-	$100	$1,027

* 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 increase in annual interest expense.

For detail of debt by category, see Note 7, Credit Facility and Debt, in the Notes to Consolidated 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 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, 2007, the likelihood of significant losses associated with credit risk in trade accounts receivable is considered to be remote.

The following table presents PGE's credit exposure for commodity activities and their subsequent maturity as of December 31, 2007. 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**	**2008**	**2009**	**2010**	**2011**	**2012**	**There-after**
Externally rated:									
Investment grade	$114	98%	$27	$51	$18	$17	$14	$12	$2
Non-Investment grade	1	1%	1	1	-	-	-	-	-
Internally rated:									
Investment grade	1	1%	-	1	-	-	-	-	-
Total	$ 116	100%	$ 28	$ 53	$ 18	$ 17	$ 14	$ 12	$ 2

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. As of December 31, 2007, there was no posted collateral subject to be returned to a counterparty that is affiliated with master netting agreements.

Omitted from the 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.

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 Consolidated Financial Statements.

Item 8. Financial Statements and Supplementary Data

Report of Independent Registered Public Accounting Firm

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

We have audited the accompanying consolidated balance sheets of Portland General Electric Company and subsidiaries (the "Company") as of December 31, 2007 and 2006, and the related consolidated statements of income, shareholders' equity, comprehensive income, and cash flows for each of the three years in the period ended December 31, 2007. Our audits also included the financial statement schedule listed in Item 15(a). We also have audited the Company's internal control over financial reporting as of December 31, 2007, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements and financial statement schedules, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on these financial statements and the financial statement schedule and an opinion on the Company's internal control over financial reporting based on our audits.

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

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

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Portland General Electric Company and subsidiaries as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, 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, present fairly, in all material respects, the information set forth therein. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

As discussed in Notes 1 and 2 to the consolidate 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*.

/s/ Deloitte & Touche LLP
Portland, Oregon
February 27, 2008

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

Years Ended December 31	**2007**	**2006**	**2005**
Revenues	$ 1,743	$ 1,520	$ 1,446
Operating expenses:			
Purchased power and fuel	879	763	671
Production and distribution	150	140	128
Administrative and other	184	164	168
Depreciation and amortization	181	219	233
Taxes other than income taxes	80	75	74
Income taxes	71	38	46
Total operating expenses	1,545	1,399	1,320
Income from operations	198	121	126
Other income (deductions):			
Allowance for equity funds used during construction	16	16	8
Miscellaneous	8	1	(5)
Income taxes	(3)	2	3
Total other income	21	19	6
Interest expense	74	69	68
Net income	$ 145	$ 71	$ 64
Common Stock:			
Weighted-average shares outstanding (in thousands):			
Basic	62,512	62,501	62,500
Diluted	62,534	62,505	62,500
Earnings per share - basic and diluted	$ 2.33	$ 1.14	$ 1.02
Dividends declared per share	$ 0.93	$ 0.675	$ *

* Not meaningful as PGE 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 BALANCE SHEETS
(In millions, except share amounts)

At December 31	2007	2006
ASSETS		
Electric utility plant, net:		
Electric utility plant at cost (includes construction work in progress of $126 and $412)	$ 5,024	$ 4,582
Less: accumulated depreciation and amortization	(1,958)	(1,864)
Electric utility plant, net	3,066	2,718
Other property and investments:		
Nuclear decommissioning trust, at market value	46	42
Non-qualified benefit plan trust	69	70
Miscellaneous	19	26
Total other property and investments	134	138
Current assets:		
Cash and cash equivalents	73	12
Accounts and notes receivable (less allowance for uncollectible accounts of $5 and $45)	178	177
Unbilled revenues	92	88
Assets from price risk management activities	64	93
Inventories, at average cost	64	64
Other current assets	67	93
Total current assets	538	527
Regulatory assets	304	351
Other noncurrent assets	66	33
Total assets	$ 4,108	$ 3,767
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Common stock, no par value, 80,000,000 shares authorized; 62,529,787 and 62,504,767 shares issued and outstanding at December 31, 2007 and 2006, respectively	$ 646	$ 643
Accumulated other comprehensive loss	(4)	(6)
Retained earnings	674	587
Total shareholders' equity	1,316	1,224
Long-term debt	1,313	937
Total capitalization	2,629	2,161
Commitments and Contingencies (see Notes)		
Current liabilities:		
Accounts payable and other accruals	227	212
Liabilities from price risk management activities	101	155
Accrued taxes	23	14
Short-term borrowings	-	81
Long-term debt due within one year	-	66
Other current liabilities	40	34
Total current liabilities	391	562
Regulatory liabilities	574	523
Deferred income taxes	279	251
Non-qualified benefit plan liabilities	86	84
Trojan asset retirement obligation	62	108
Accumulated asset retirement obligation	29	26
Other noncurrent liabilities	58	52
Total liabilities	1,479	1,606
Total capitalization and liabilities	$ 4,108	$ 3,767

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

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(Dollars in millions)

	Common Stock		Accumulated Other Comprehensive Loss	Retained Earnings	Total Shareholders' Equity
	Shares	Amount			
Balances at December 31, 2004	62,500,000	$642	$(6)	$ 644	$1,280
Dividends declared	-	-	-	(150)	(150)
Net income	-	-	-	64	64
Other comprehensive income	-	-	3	-	3
Balances at December 31, 2005	62,500,000	642	(3)	558	1,197
Vesting of restricted stock units	4,767	-	-	-	-
Stock-based compensation	-	1	-	-	1
Dividends declared	-	-	-	(42)	(42)
Net income	-	-	-	71	71
Other comprehensive income	-	-	1	-	1
Initial adjustment to adopt SFAS 158	-	-	(4)	-	(4)
Balances at December 31, 2006	62,504,767	643	(6)	587	1,224
Vesting of restricted stock units	16,841	-	-	-	-
Shares issued pursuant to employee stock purchase plan	8,179	-	-	-	-
Stock-based compensation	-	3	-	-	3
Dividends declared	-	-	-	(58)	(58)
Net income	-	-	-	145	145
Other comprehensive income	-	-	2	-	2
Balances at December 31, 2007	62,529,787	$646	$(4)	$ 674	$1,316

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

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

Years Ended December 31	2007	2006	2005
Net income	$145	$ 71	$ 64
Other comprehensive income (loss) items, net of taxes:			
Unrealized gains (losses) on cash flow hedges:			
Unrealized holding net gains (losses), net of taxes of $2 in 2007, $16 in 2006, and $(18) in 2005	(2)	(26)	28
Reclassification to net income for contract settlements, net of taxes of $(1) in 2007, $7 in 2006, and $(3) in 2005	2	(11)	4
Reclassification to net income due to discontinuance of cash flow hedges, net of taxes of $1 in 2005	-	-	(1)
Reclassification of unrealized gains (losses) to SFAS 71 regulatory asset (liability), net of taxes of $(1) in 2007, $(24) in 2006, and $19 in 2005	-	37	(29)
Total unrealized gains on cash flow hedges	-	-	2
Pension and other postretirement plans' funded position, net of taxes of $(12)	20	-	-
Reclassification of defined benefit pension plan and other benefits to SFAS 71 regulatory asset, net of taxes of $12	(18)	-	-
Minimum pension liability adjustment	-	1	1
Total other comprehensive income items, net of taxes	2	1	3
Comprehensive income	$147	$ 72	$ 67

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

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

Years Ended December 31	**2007**	**2006**	**2005**
Cash flows from operating activities:			
Net income	$ 145	$ 71	$ 64
Reconciliation of net income to net cash provided by operating activities:			
Depreciation and amortization	181	219	233
Net assets from price risk management activities	(26)	132	(40)
Regulatory deferrals - price risk management activities	26	(132)	36
Deferred income taxes	22	(38)	(53)
Allowance for equity funds used during construction	(16)	(16)	(8)
Senate Bill 408 deferrals	(16)	42	-
Power cost deferrals	(9)	-	18
Other non-cash income and expenses, net	1	-	16
Changes in working capital:			
Net margin deposit activity	21	(94)	35
(Increase) decrease in receivables	(4)	17	(29)
Increase (decrease) in payables	19	(88)	82
Other working capital items, net	(2)	(11)	4
Other, net	2	4	14
Net cash provided by operating activities	344	106	372
Cash flows from investing activities:			
Capital expenditures	(455)	(371)	(255)
Purchases of nuclear decommissioning trust securities	(23)	(37)	(34)
Sales of nuclear decommissioning trust securities	21	21	21
Proceeds from sale of assets	-	6	-
Other, net	6	1	(4)
Net cash used in investing activities	(451)	(380)	(272)
Cash flows from financing activities:			
Issuance of long-term debt	381	275	-
Short-term borrowings, net	(81)	81	-
Repayment of long-term debt	(71)	(162)	(32)
Dividends paid	(58)	(28)	(150)
Debt issuance costs	(3)	(2)	-
Net cash provided by (used in) financing activities	168	164	(182)
Increase (decrease) in cash and cash equivalents	61	(110)	(82)
Cash and cash equivalents, beginning of year	12	122	204
Cash and cash equivalents, end of year	$ 73	$ 12	$ 122

Supplemental disclosures of cash flow information:			
Cash paid during the year:			
Interest, net of amounts capitalized	$ 58	$ 55	$ 58
Income taxes	46	101	88
Non-cash investing and financing activities:			
Accrued capital additions	27	20	9
Common stock dividends declared but not paid	15	14	-

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

Nature of Operations

Portland General Electric Company (PGE, or the Company) is a single, vertically integrated electric utility engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the State of Oregon. The Company also sells electricity and natural gas in the wholesale market to utilities, brokers, and power marketers 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 corporate headquarters is located in Portland, Oregon and its service area is located entirely within Oregon. PGE's service area includes 52 incorporated cities, of which Portland and Salem are the largest, within a state-approved service area allocation of approximately 4,000 square miles. At the end of 2007, PGE's service area population was approximately 1.6 million, comprising about 43% of the state's population. The Company served approximately 804,000 retail customers at December 31, 2007.

Note 1 - Summary of Significant Accounting Policies

Consolidation Principles

The consolidated financial statements include the accounts of PGE and its wholly-owned subsidiaries. The Company's ownership share of direct expenses and costs related to jointly-owned generating plants are also included in the consolidated financial statements. Intercompany balances and transactions have been eliminated.

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, and disclosures of contingent 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 No. (SFAS) 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. Specifically, "Allowance for equity funds used during construction" and "Senate Bill 408 deferrals," previously classified within "Other non-cash income and expenses, net" on the Consolidated Statements of Cash Flows, are now reported separately. These reclassifications had no effect on PGE's previously reported consolidated financial position, results of operations, or cash flows.

Revenue Recognition

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). 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 71, *Accounting for the Effects of Certain Types of Regulation*.

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 "Revenue Recognition" in this Note).

Price Risk Management

PGE engages in price risk management activities in its electric business, utilizing derivative instruments such as forward, swap, and option contracts for electricity and natural gas, and futures contracts for natural gas. Under SFAS 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.

Certain electricity forward contracts that were entered into in anticipation of serving the Company's regulated retail load meet the requirements for treatment under the normal purchases and normal sales exception under SFAS 133, as amended by SFAS 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities*. Other 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. 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 derivative contracts only at the time of settlement. Contracts that qualify for the normal purchases and normal sales exception are not required to be recorded at fair value. Unrealized gains and losses from contracts that qualify as cash flow hedges are recorded net in Other comprehensive income (OCI) and contracts designated as non-hedges are recorded net in Purchased power and fuel expense on the Statements of Income. The timing difference between the recognition of unrealized gains and losses on derivative instruments and their realization and subsequent recovery in rates is recorded as a regulatory asset or regulatory liability to reflect the effects of regulation under SFAS 71.

Prior to December 2006, PGE recorded a regulatory asset or regulatory liability under SFAS 71 to offset unrealized gains and losses on certain contracts recorded prior to settlement to the extent that such contracts were 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 17, 2007 general rate order, the OPUC approved a new Power Cost Adjustment Mechanism (PCAM) by which PGE can adjust future rates to reflect a portion of the difference between each year's forecasted and actual net variable power costs (NVPC). 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 with the January 17, 2007 order, a new Annual Power Cost Update Tariff replaced the RVM.

Sales and purchases involving electricity derivative activities that are physically settled are recorded in Revenues and Purchased power and fuel expense, respectively. 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 No. (EITF) 03-11, *Reporting 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" as Defined in Issue 02-3.* For further information, see Note 10.

Stock-Based Compensation

Stock-based compensation is accounted for in accordance with SFAS 123 (revised 2004), *Share-based Payments* (SFAS 123R), which requires the measurement and recognition of compensation expense for all share-based payment awards, including restricted stock units, based on the estimated fair value of the awards. Under SFAS 123R, the fair value of the portion of the award that is ultimately expected to vest is recognized as expense over the requisite service period. PGE attributes the value of stock-based compensation to expense on a straight-line basis. For further information, see Note 5.

Counterparty and 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 counterparties under such agreements are reflected as margin deposits and classified in Other current assets in the Consolidated Balance Sheets and were \$28 million and \$46 million at December 31, 2007 and 2006, respectively. Amounts received from counterparties under such agreements are reflected as customer deposits and are classified in Other current liabilities in the Consolidated Balance Sheets and were \$8 million and \$5 million at December 31, 2007 and 2006, respectively, which includes certain retail and transmission customer deposits received.

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 consists of the following (in millions):

	December 31,	
	2007	2006
Production	$ 1,944	$ 1,414
Transmission	329	283
Distribution	2,184	2,059
General	252	242
Intangible	189	172
Construction work in progress	126	412
Total electric utility plant	$ 5,024	$ 4,582

Depreciation and Amortization of Property, Plant and Equipment

Depreciation is computed using the straight-line method, based upon original cost and includes an estimate for cost of removal and expected salvage. Depreciation expense as a percent of the related average depreciable plant in service was approximately 3.9% in 2007, 4.3% in 2006, and 4.4% in 2005. Estimated asset retirement removal costs included in depreciation expense were $43 million, $68 million, and $64 million in 2007, 2006, and 2005, respectively. The reductions in 2007 are related to PGE's most recent depreciation study, as described below.

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 incorporated into customer rates that became effective on January 17, 2007.

Thermal production plants are depreciated using a life-span methodology which ensures that plant investment is recovered by the forecasted retirement date. These dates range from 2020 to 2042. Depreciation is provided on the Company's other classes of plant in service over their estimated average service lives, which are as follows: Hydro, 88 years; Wind, 27 years; Transmission, 48 years; Distribution, 38 years; and General, 14 years.

The original cost of depreciable property units, net of any related salvage value, is charged to accumulated depreciation when property is retired and removed from service. Cost of removal expenditures are charged to asset retirement obligations for assets with AROs and to accumulated asset retirement removal costs, included in Regulatory liabilities, for assets without AROs. For further information, see Note 12.

Intangible plant consists primarily of computer software development costs, which are amortized over either five or ten years, and hydro relicensing costs, which are amortized over the applicable license term. Amortization expense for 2007, 2006, and 2005, was $15 million, $15 million, and $13 million, respectively. Accumulated amortization was $96 million and $82 million at December 31, 2007 and December 31, 2006, respectively.

Major Maintenance Expenses

Costs of periodic major maintenance inspections and overhauls at the Company's generating plants are charged to operating expense as incurred. Due to the variability of major maintenance expenses at the Coyote Springs combustion turbine generating plant, PGE's retail customer prices include the recovery of an annual amount, as authorized by the OPUC. Differences between amounts authorized in prices and actual Coyote Springs maintenance expenses are deferred as regulatory assets or regulatory liabilities pursuant to SFAS 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 rate used by PGE in 2007 was 8%, while the rates for 2006 and 2005 were 9%. AFDC from borrowed funds was $10 million in 2007, $8 million in 2006, and $4 million in 2005 and is reflected in the Consolidated Statements of Income as a reduction to interest expense. AFDC from equity funds was $16 million in 2007, $16 million in 2006, and $8 million in 2005 and is reflected as a component of Other income (deductions).

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, 2007 and 2006 were $16 million and $15 million, respectively, and are included within Other noncurrent assets 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 recorded for temporary differences between financial and income tax reporting. Investment tax credits utilized have been deferred and are being amortized to income over a period which will end in 2011, which corresponds with the lives of the related properties. Interest and penalties related to any future income tax deficiencies will be recorded within Interest expense and Other income (deductions), respectively, in the Consolidated Statements of Income.

Cash and Cash Equivalents

Highly liquid investments with maturities of three months or less at the date of acquisition are classified as cash equivalents. Cash equivalents consist of money market funds and total $59 million and zero at December 31, 2007 and 2006.

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. For further information, see Note 2. The cash surrender values of insurance contracts, the majority of which are held in the trust, were $22 million and $23 million at December 31, 2007 and 2006, respectively. 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 are determined using average cost and are included in Other income (deductions) on the Consolidated Statements of Income. Investments in marketable securities and cash totaled $47 million at December 31, 2007 and 2006.

Accumulated Other Comprehensive Income

SFAS 130, *Reporting Comprehensive Income,* establishes standards for the reporting of comprehensive income and its components. Accumulated other comprehensive income (AOCI) is comprised of the difference between the pension and other postretirement plans' obligations recognized in earnings to date, and the funded position at December 31, 2007 and 2006. With the adoption of SFAS 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans* (SFAS 158) on December 31, 2006, PGE recorded an initial adjustment to reflect the provisions of SFAS 158.

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 consist of the following (in millions):

	December 31,	
	2007	**2006**
Coal	$16	$20
Fuel oil	10	10
Natural gas	3	3
Materials and supplies	32	28
Unallocated stores account	3	3
Total	$64	$64

Asset Retirement Obligations

Asset retirement obligations are accounted for in accordance with SFAS 143, *Accounting for Asset Retirement Obligations,* which requires that the fair value of a liability for an ARO be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. Because of the long lead time involved until future decommissioning activities occur, the Company uses present value techniques as quoted market prices and a market-risk premium are not available. The present value of estimated future removal expenditures, which is revised periodically, is recorded as an ARO on the Consolidated Balance Sheets, with actual expenditures charged to the ARO as incurred. For further information, see Notes 12 and 13.

Regulatory Assets and Liabilities

As a rate-regulated enterprise, the Company applies SFAS 71, *Accounting for the Effects of Certain Types of Regulation* (SFAS 71). Regulatory assets represent probable future revenue associated with certain costs that will be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are to be credited to customers through the ratemaking process. Accounting under SFAS 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.

As of December 31, 2007, the majority of PGE's regulatory assets and liabilities are reflected in customer rates and are amortized over the period in which they are included in billings to customers. Items not currently reflected in rates are pending before the regulatory body as discussed below. 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 12 years.

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

	December 31,	
	2007	**2006**
Regulatory assets:		
Income taxes recoverable (1)	$ 87	$ 74
Pension and other postretirement plans (1)	57	87
Price risk management (1)	37	62
Boardman power cost deferral (2)	31	6
Debt reacquisition costs (1)	28	30
Trojan decommissioning costs	16	66
Oregon Senate Bill 408 (SB 408) - 2007 (2)	16	-
Residential Exchange Program (2)	9	-
Regulatory restructuring costs (2)	5	11
Beaver 8 (2)	5	7
Miscellaneous (3)	13	8
Total regulatory assets	$ 304	$ 351
Regulatory liabilities:		
Accumulated asset retirement removal costs	$ 451	$ 411
Oregon Senate Bill 408 (SB 408) - 2006 (2)	42	42
Asset retirement obligations	28	27
Trojan ISFSI pollution control tax credits (2)	13	10
Power Cost Adjustment Mechanism (PCAM) (2)	16	-
Residential Exchange Program (2)	-	14
Miscellaneous (4)	24	19
Total regulatory liabilities	$ 574	$ 523

(1) At December 31, 2007, PGE had regulatory assets not earning a return on investment of $212 million.

(2) 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).

(3) Of the total miscellaneous unamortized balances, a return is recorded on $3 million at both December 31, 2007 and 2006 at PGE's authorized cost of capital, as indicated in (2) above.

(4) Of the total miscellaneous unamortized balances, a return is recorded on $12 million and $15 million at December 31, 2007 and 2006, respectively, at PGE's authorized cost of capital, as indicated in (2) above.

Circumstances that could result in the discontinuance of SFAS 71 include (1) increased competition that restricts the Company's ability to establish prices to recover specific costs, and (2) a significant change in the manner in which rates are set by regulators from cost-based regulation to another form of regulation. PGE periodically reviews the criteria of SFAS 71 to ensure that its continued application is appropriate. Based on a current evaluation of the various factors and conditions that are expected to impact future cost recovery, management believes that the Company's regulatory assets are probable of future recovery.

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. PGE expects recovery over the next 17 years.

Pension and other postretirement plans - On December 31, 2006, PGE adopted SFAS 158, which requires that the funded status of pension and other postretirement plans be recognized, with the resulting adjustment recorded to the ending balance of AOCI on the Consolidated Balance Sheets. Postretirement costs are covered in rates charged to customers. The OPUC issued an accounting order that authorizes PGE to record a regulatory asset equal to the pre-tax charge against AOCI that would otherwise be required by recognition of the pension funded status under SFAS 158. As pension expense is recognized in future years, the regulatory asset will be reduced. PGE expects recovery over the average service life of its employees. For further information, see Note 2.

Price risk management - SFAS 133 requires that unrealized gains and losses on derivative instruments that do not qualify for the normal purchase and normal sale exception be recorded in earnings or OCI in the current period. To reflect the effects of regulation under SFAS 71, timing differences between the recognition of unrealized gains and losses on 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, 2007 and 2006 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. PGE expects recovery over the next 4 years. For further information, see Note 10.

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. On February 12, 2007, the OPUC issued an order granting a portion of PGE's request and authorizing the Company to defer $26.4 million, subject to a prudency review process. PGE recorded the deferral of $20.4 million in the first quarter 2007. On October 9, 2007, PGE filed a request with the OPUC to amortize the deferral of $26.4 million of replacement power costs, plus interest until the amortization period begins (accrued interest is $5.0 million as of December 31, 2007), associated with the outage of Boardman from November 18, 2005 through February 5, 2006. In its filing, the Company proposed that the amortization be offset with certain credits due to customers, with no price impact anticipated. PGE's request is subject to both a prudency review with respect to the outage and to a regulated earnings test.

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. PGE expects recovery over the next 25 years.

Trojan decommissioning costs - PGE's retail prices include recovery of costs to decommission Trojan. These amounts represent the estimated present value of future decommissioning expenditures to be recovered from customers. For further information, see Note 13.

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. The Company has established a regulatory liability for future refunds to customers related to the 2006 reporting year. PGE filed its report on October 15, 2007 with the OPUC reflecting the amount of taxes paid by the Company, as well as the amount of taxes authorized to be collected in rates. The report is being reviewed as part of a formal process, with the OPUC expected to issue an order in April 2008. The Company has reached agreement with OPUC Staff and certain interveners that the appropriate refund due customers is $37.2 million plus accrued interest, based on the OPUC's administrative rules that govern the calculation of the refund amount. This regulatory liability includes $17 million paid to Enron Corp. for net current taxes payable for the first quarter of 2006 when PGE was included in its former parent's consolidated group for filing consolidated federal and state income tax returns. Under OPUC rules, refunds to customers for the 2006 reporting year will begin on June 1, 2008. For 2007, a regulatory asset was established for collection from customers. For further information, see Note 15.

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. Based upon decisions in the U.S. Ninth Circuit Court of Appeals, the BPA, on May 21, 2007, notified PGE and six other investor-owned utilities that it was immediately suspending the Residential Exchange Program payments. In its notice, the BPA indicated that the suspension will continue at least until any petitions for rehearing on the decisions are finally resolved. The $9 million regulatory asset represents Residential Exchange Program credits that were passed through to eligible customers but not received from the BPA.

Regulatory restructuring costs - The OPUC authorized PGE to defer certain costs related to implementation of Oregon's electricity restructuring law. Of the $24 million total implementation costs, $7 million was fully recovered over a five-year period that ended December 31, 2007, and $17 million is being recovered over a five-year period that began on January 1, 2004, with a remaining balance of $5 million at December 31, 2007.

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 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, with the remaining $4 million to be recovered through depreciation charges included in general prices.

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 143 and SFAS 71. This amount is also included as a reduction to PGE's rate base for ratemaking purposes.

Asset retirement obligations - SFAS 143 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 71. Asset retirement obligations are included in PGE's rate base for ratemaking purposes. For further information, see Note 13.

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.

Power Cost Adjustment Mechanism (PCAM) - A new PCAM was approved by the OPUC, effective January 17, 2007. Under the PCAM, PGE can adjust future prices to reflect a portion of the difference between each year's forecasted NVPC included in prices (the baseline), and actual NVPC. Under the PCAM, PGE is subject to a portion of the business risk or benefit associated with the difference between actual NVPC and that included in base prices by application of an asymmetrical deadband within which PGE absorbs cost increases or decreases, with a 90/10 sharing of costs and benefits between customers and the Company outside of the deadband. For 2007, the deadband ranged from $11.7 million below, to $23.4 million above, the baseline. PGE's actual NVPC as determined under the PCAM for 2007 were less than the established baseline by $29.4 million, thus an estimated refund to customers of $16.5 million, including accrued interest, was recorded as a regulatory liability and is reflected as an increase to Purchased power and fuel expense. A final determination of any customer refund or collection will be determined by the OPUC through a public filing and review.

New Accounting Standards

SFAS 157, *Fair Value Measurements* (SFAS 157), was issued in September 2006 and is effective for fiscal years beginning after November 15, 2007. (In February 2008, the FASB deferred the effective date of SFAS 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis). SFAS 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 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 believes that the adoption of SFAS 157 will not have a material impact on its consolidated financial position or consolidated results of operations.

SFAS 159, *The Fair Value Option for Financial Assets and Financial Liabilities* (SFAS 159), was issued in February 2007 and is effective for fiscal years beginning after November 15, 2007. SFAS 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 believes that the adoption of SFAS 159 will not have a material impact on its consolidated financial position or consolidated results of operations.

FASB Staff Position No. FIN 39-1, *Amendment of FASB Interpretation No. 39* (FSP FIN 39-1) was issued April 30, 2007 and modifies FIN 39, *Offsetting of Amounts Related to Certain Contracts*, and permits reporting entities to offset the receivable or payable recognized for derivative instruments that have been offset under a master netting arrangement. FSP FIN 39-1 requires financial statement disclosure of a reporting entity's accounting policy (to offset or not to offset) as well as amounts recognized for the right to reclaim cash collateral, or the obligation to return cash collateral, that have been offset against net derivative positions. FSP FIN 39-1 is effective for fiscal years beginning after November 15, 2007, with early application permitted. The effects of applying FSP FIN 39-1 shall be presented as a change in accounting principle through retrospective application for all financial statements presented unless it is impracticable to do so. PGE is in the process of determining the impact the application of FSP FIN 39-1 will have on its consolidated financial position, but believes the adoption of FSP FIN 39-1 will not have a material impact on its consolidated results of operations.

EITF 06-11, *Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards* (EITF 06-11) was ratified by the Emerging Issues Task Force at its June 27, 2007 meeting. EITF 06-11 clarifies how an entity should (1) recognize the income tax benefit received on dividends that are paid to employees holding equity-classified nonvested shares and (2) charged to retained earnings under SFAS 123R. EITF 06-11 applies prospectively to the income tax benefits that result from dividends on equity-classified employee share-based payment awards that are declared in fiscal years beginning after December 15, 2007, and interim periods within those fiscal years. PGE believes the adoption of EITF 06-11 will not have a material impact on its consolidated financial position or consolidated results of operations.

Note 2 - Employee Benefits

Pension and Other Postretirement 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 and are updated as appropriate.

PGE made no contributions to the pension plan in 2006 and 2007 and does not currently expect to make any contribution in 2008. The measurement date for the pension plan is December 31.

Non-Qualified Benefit Plans - The Non-Qualified Benefit Plans in the accompanying table consist primarily of 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 funding these plans. Trust assets of $25 million as of December 31, 2007 and 2006 are included in the accompanying table for informational purposes only and are not considered segregated and restricted as defined by SFAS 158. The investments in marketable securities, consisting of money market, bond, and equity mutual funds, are classified as trading and recorded at fair value. The measurement date for the non-qualified plans is December 31.

Other Benefits - PGE also participates in non-contributory postretirement 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.

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 participants' accounts are credited with 58% of the value of the employee's accumulated sick time as of April 30, 2004 and 100% of their earned time off accumulated at the time of retirement. Between July 1, 2007 and June 30, 2008, the Company will make additional contributions to the trust of $0.25 per compensable hour for each participant, increasing to $0.50 per compensable hour through February 28, 2009. The Company also grants 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 postretirement or non-bargaining HRA plans in 2007. Contributions totaling $1 million were made to the bargaining unit HRA in 2007, with similar contributions expected in 2008. No contributions are currently expected to be made to the other postretirement plans in 2008. The measurement date for the postretirement plans is December 31.

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	
	2007	2006	2007	2006	2007	2006
Reconciliation of benefit obligation:						
Benefit obligation at January 1	$ 492	$ 483	$ 26	$ 24	$ 58	$ 59
Service cost	13	13	-	-	2	1
Interest cost	27	27	1	2	4	3
Plan amendments	-	-	-	-	5	-
Participants' contributions	-	-	-	-	1	1
Actuarial (gain) loss	(31)	(6)	(2)	2	3	(2)
Prior service cost	-	-	1	-	-	-
Benefit payments	(26)	(25)	(2)	(2)	(5)	(4)
Benefit obligation at December 31	$ 475	$ 492	$ 24	$ 26	$ 68	$ 58
Reconciliation of fair value of plan assets:						
Fair value of plan assets at January 1	$ 503	$ 469	$ 25	$ 24	$ 28	$ 27
Actual return on plan assets	41	59	2	3	2	3
Company contributions	-	-	-	-	1	1
Participants' contributions	-	-	-	-	1	1
Benefit payments	(26)	(25)	(2)	(2)	(5)	(4)
Fair value of plan assets at December 31	$ 518	$ 503	$ 25	$ 25	$ 27	$ 28
Funded (unfunded) status at December 31	$ 43	$ 11	$ 1	$ (1)	$ (41)	$ (30)
Accumulated benefit obligation at December 31	$ 420	$ 436	$ 20	$ 20	N/A	N/A
Amounts in the Consolidated Balance Sheets consist of:						
Noncurrent asset	$ 43	$ 11	$ -	$ -	$ -	$ -
Current liability	-	-	(1)	(2)	-	-
Noncurrent liability	-	-	(23)	(24)	(41)	(30)
Net asset (liability)	$ 43	$ 11	$ (24)	$ (26)	$ (41)	$ (30)
Amounts recognized in comprehensive income consist of:						
Net actuarial loss/(gain)	$ (30)	$ *	$ (2)	$ -	$ 3	$ *
Prior service cost	-	*	1	-	5	*
Amortization of net actuarial loss	(3)	*	(1)	-	-	*
Amortization of prior service cost	(1)	*	-	-	(3)	*
Amortization of transition obligation	-	*	-	-	(1)	*
Minimum pension liability adjustment	N/A	*	N/A	(1)	N/A	*
Net amount recognized	$ (34)**	$ *	$ (2)	$ (1)	$ 4 **	$ *
Amounts in AOCI consist of:						
Net actuarial loss	$ 36	$ 69	$ 7	$ 9	$ 10	$ 7
Prior service cost	3	4	-	-	8	6
Transition obligation	-	-	-	-	-	1
Net amount	$ 39 **	$ 73 **	$ 7	$ 9	$ 18 **	$ 14 **
Assumptions:						
Discount rate used to calculate benefit obligation	6.50 %	5.75 %	6.50 %	5.75 %	5.75 % - 6.25 %	5.75 %
Weighted-average rate of increase in future compensation levels	4.42%	4.44%	N/A	N/A	5.07 %	5.07%
Long-term rate of return on assets	9.00%	9.00%	N/A	N/A	8.14 %	8.17%

* No activity in 2006, as SFAS 158 required an implementation adjustment to ending AOCI.

** Subsequently transferred to Regulatory assets.

	Defined Benefit Pension Plan			Non-Qualified Benefit Plans			Other Benefits		
	2007	2006	2005	2007	2006	2005	2007	2006	2005
Components of net periodic benefit cost:									
Service cost	$ 13	$ 13	$ 12	$ -	$ -	$ -	$ 2	$ 1	$ 1
Interest cost on benefit obligation	27	27	25	1	1	1	4	3	3
Expected return on plan assets	(42)	(41)	(41)	-	-	-	(2)	(2)	(2)
Amortization of transition obligation	-	-	-	-	-	-	1	1	1
Amortization of prior service cost	1	1	2	-	-	1	3	1	1
Amortization of net actuarial loss	3	4	2	1	1	-	-	1	1
Actual return on plan assets	-	-	-	(2)	(2)	(1)	-	-	-
Net periodic benefit cost	$ 2	$ 4	$ -	$ -	$ -	$ 1	$ 8	$ 5	$ 5

PGE estimates that $4 million will be amortized from AOCI into net periodic benefit cost in 2008, consisting of a net actuarial loss of $1 million for non-qualified benefits, prior service cost of $1 million each for pension benefits and other benefits, and a transition obligation of $1 million for other benefits.

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

	Payments Due					
	2008	2009	2010	2011	2012	2013 - 2017
Pension plan	$ 27	$ 30	$ 30	$ 32	$ 34	$ 191
Non-qualified plan	2	2	1	1	2	12
Other plans	4	4	5	5	5	26
Total	$ 33	$ 36	$ 36	$ 38	$ 41	$ 229

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 2008. The rate is assumed to decrease to 5% by 2015 and remain at that level thereafter. Assumed health care cost trend rates can affect amounts reported for the health care plans. A one-percentage point increase or decrease in assumed health care cost trend rates would not have a material impact on total service or interest cost, but would increase the postretirement benefit obligation by $1 million and decrease it by $1 million, respectively.

The pension plan asset allocation was 67% equity securities and 33% debt securities as of December 31, 2007 and 2006, with a target asset allocation of the same ratio for December 31, 2008.

The asset allocations for the Non-Qualified Benefit Plans and Other Benefit Plans at December 31, 2007 and 2006, and the target allocation for 2008, are as follows:

	Percentage of Plan Assets at December 31,		Target Allocation
	2007	2006	2008
Non-Qualified Benefit Plans:			
Cash equivalents	1%	1%	-
Debt securities	18%	11%	16%
Equity securities	40%	42%	38%
TOLI policies	41%	46%	46%
Total	100%	100%	100%
Other Benefit Plans:			
Equity Securities	66%	62%	67%
Debt Securities	34%	38%	33%
Total	100%	100%	100%

An insurable interest in the respective employees is required for investment in TOLI policies.

The investment policies of the pension and other postretirement plans call for permanent commitment to four 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 takes profits from asset classes whose allocations have shifted above their target ranges to fund benefit payments and investments in asset classes whose allocations have shifted below their target ranges.

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 $62 million and $60 million at December 31, 2007 and 2006, respectively (not included in table). The costs of the SERP and MDCPs are excluded from prices charged to customers. Investments in TOLI and marketable securities are intended to be the primary source for financing the MDCPs. Total assets held in support of the MDCPs were $41 million and $43 million at December 31, 2007 and 2006, respectively. Unrealized gains on marketable securities were $1 million for 2007, $4 million for 2006, and $1 million for 2005.

PGE sponsors additional non-qualified plans for certain employees and former directors. Obligations for these plans were $1 million at December 31, 2007 and 2006. Assets held in support of these plans were $2 million at December 31, 2007 and 2006.

401(k) Retirement Savings Plan

PGE sponsors a 401(k) Plan, which covers substantially all employees. Contributions to the 401(k) 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 and vest after one year of service.

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 $14 million in 2007, and $13 million in both 2006 and 2005.

Note 3 - Income Taxes

Income tax expense is comprised of the following (dollars in millions):

	Years Ended December 31,		
	2007	2006	2005
Current:			
Federal	$50	$ 66	$ 88
State and local	3	8	8
	53	74	96
Deferred:			
Federal	20	(29)	(41)
State and local	4	(6)	(9)
	24	(35)	(50)
Investment tax credit adjustments	(3)	(3)	(3)
Total income tax expense	$74	$ 36	$ 43
Income tax expense allocated to:			
Operations	$71	$ 38	$ 46
Other income and deductions	3	(2)	(3)
Total income tax expense	$74	$ 36	$ 43

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

	Years Ended December 31,		
	2007	2006	2005
Computed tax based on statutory federal income tax rate (35%) applied to income before income taxes	$ 76	$ 38	$ 37
State and local taxes - net of federal tax benefit	5	2	1
Flow through depreciation	(3)	5	7
Investment tax credits	(3)	(3)	(3)
Adjustments for previously recorded taxes	-	(4)	2
Other	(1)	(2)	(1)
Total income tax expense	$ 74	$ 36	$ 43
Effective tax rate	33.8%	33.5%	39.9%

As of December 31, 2007 and 2006, the significant components of PGE's deferred income tax assets and liabilities were as follows (in millions):

	December 31, 2007	December 31, 2006
Deferred income tax assets:		
Regulatory liabilities:		
Asset retirement removal costs	$186	$168
SB 408 - Revenue to be refunded	16	16
Other	27	17
Employee benefits	63	72
Price risk management	34	83
Depreciation and amortization	35	34
Allowance for uncollectible accounts	3	19
Other	10	5
Total deferred income tax assets	374	414
Deferred income tax liabilities:		
Depreciation and amortization	493	458
Regulatory assets:		
Pension	22	34
Debt reacquisition costs	11	12
Boardman power cost deferral	10	2
SB 408 - Revenue to be collected	5	-
Miscellaneous	11	9
Price risk management	36	85
Employee benefits	27	24
Nuclear decommissioning trust	10	7
Property taxes	6	5
Other	9	7
Total deferred income tax liabilities	640	643
Net deferred income tax liability	$266	$229
Classification of net deferred income taxes:		
Included in current assets	$ 13	$ 22
Included in other noncurrent liabilities	279	251
Net deferred income tax liability	$266	$229

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

Uncertain Tax Positions - FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109* (FIN 48) was adopted by PGE on January 1, 2007. FIN 48 was issued 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 before the benefit of an uncertain tax position can be recognized in the financial statements. FIN 48 requires recognition in the financial statements of the largest amount of tax benefit that is greater than 50% likely of being realized upon settlement with a taxing authority that has full knowledge of all relevant information. Based on such assessment, PGE has recorded no liability for uncertain tax positions at date of adoption and at December 31, 2007.

PGE files income tax returns in the U.S. federal jurisdiction, the states of Oregon and Montana, and certain local jurisdictions. The Company is not currently under examination by federal, state or local tax authorities. Open tax years are 2004 and subsequent years for federal, state and local tax purposes.

Oregon Tax Credits - PGE generated approximately $13 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. Prior to 2006, pursuant to a tax sharing agreement, PGE utilized these tax credits to reduce its tax payment obligations to Enron. Uncertainties remain 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 to utilize such tax credits on its Oregon income tax returns in periods subsequent to its separation from Enron. A portion of the tax credits was utilized to offset quarterly income tax payments due to the State of Oregon during periods subsequent to April 3, 2006, with no effect on income. Any realization of these tax credits by PGE will be reflected as an adjustment to equity.

Note 4 - Preferred and Common Stock

Preferred Stock

In 2007, PGE redeemed the entire $16 million of 7.75% Series Cumulative Preferred Stock outstanding at December 31, 2006, which was classified as long-term debt. At December 31, 2007, PGE continues to have 30 million shares of preferred stock authorized, at no par value. For further information, see Note 7.

Common Stock

On April 3, 2006, PGE and Enron entered into a separation agreement and, in accordance with the Enron Chapter 11 Plan, PGE issued 62.5 million shares of common stock and cancelled the then outstanding 42.8 million shares of common stock held by Enron Corp. Following issuance of the 62.5 million shares of common stock, PGE ceased to be a subsidiary of Enron. Approximately 35.5 million shares of PGE's common stock were initially issued to a Disputed Claims Reserve (DCR). On June 18, 2007, the DCR sold substantially all of its remaining holdings of PGE stock in a public offering. PGE's common stock is listed on the New York Stock Exchange under the ticker symbol "POR".

Employee Stock Purchase Plan

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

Note 5 - Stock-Based Compensation

In 2006, PGE adopted the Portland General Electric Company 2006 Stock Incentive Plan. Under the plan, PGE may grant a variety of equity based awards, including restricted stock units with time-based vesting conditions (Restricted Stock Units) and performance-based vesting conditions (Performance Stock Units) to non-employee directors, officers and certain key employees. Service requirements generally must be met for stock units to vest. For each grant, the number of Stock Units is determined by dividing a specified award amount for each grantee by the closing stock price on the grant date. A total of 4,687,500 shares of common stock were registered for future issuance under the plan, of which 4,409,322 shares remain available for future issuance as of December 31, 2007.

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

Performance Stock Units vest if performance goals 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 the extent to which the performance goals are met. In accordance with the plan, however, in determining results relative to these goals, the committee may disregard or offset the effect of extraordinary, unusual or non-recurring items. Based on the attainment of the performance goals, the awards can range from zero to 150% of the grant.

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

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

	Units	**Weighted Average Grant Date Fair Value**
Outstanding at December 31, 2005	-	$ -
Granted	188,248	24.97
Forfeited	(3,301)	26.21
Vested	(4,767)	25.82
Outstanding at December 31, 2006	180,180	24.97
Granted	100,425	28.44
Forfeited	(7,194)	25.14
Vested	(20,160)	25.76
Outstanding at December 31, 2007	253,251	26.28

The weighted average fair value is measured based on the closing price of PGE common stock on the date of grant. For the years ended December 31, 2007 and 2006, PGE recorded $3 million and $1 million, respectively, of stock-based compensation expense (included in Administrative and other expense in the Consolidated Statements of Income), with a corresponding credit to common stock. As of December 31, 2007, unrecognized stock-based compensation expense was $4.5 million, of which $3.0 million and $1.5 million is expected to be expensed in 2008 and 2009, respectively. Stock-based compensation expense was calculated assuming the attainment of performance goals that would allow the vesting of 131% and 128% of awarded Performance Stock Units for 2007 and 2006, respectively, with an estimated 5% forfeiture rate. No stock-based compensation costs have been capitalized and the plan had no material impact on cash flow for the years ended December 31, 2007 or 2006.

Note 6 - Earnings Per Share

Basic earnings per share is computed based on the weighted average number of common shares outstanding during the period. Diluted earnings per share is computed using the weighted average number of common shares outstanding and the effect of dilutive potential common shares outstanding during the period using the treasury stock method. Dilutive potential common shares consist of Restricted Stock Units. Restricted and Performance Stock Units and DERs are discussed in Note 5. Unvested Performance Stock Units and related DERs are not included in the computation of dilutive securities because vesting of these instruments is dependent upon three-year performance periods, as discussed in Note 5.

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

	Years Ended December 31,		
	2007	**2006**	**2005**
Numerator (in millions):			
Net income available for common shareholders	$ 145	$ 71	$ 64
Denominator (in thousands):			
Weighted-average common shares outstanding-basic	62,512	62,501	62,500
Dilutive effect of restricted stock units	22	4	-
Weighted-average common shares outstanding-diluted	62,534	62,505	62,500
Earnings per share - basic and diluted	$ 2.33	$ 1.14	$ 1.02

Note 7 - Credit Facility and Debt

At December 31, 2007, PGE had a $400 million five-year unsecured revolving credit facility with a group of commercial and investment banks. The facility, which expires in 2012, 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. As of December 31, 2007, PGE was in compliance with this covenant.

PGE has two series of First Mortgage Bonds outstanding that are insured under agreements with a bond insurer. One agreement, which insures the $100 million of 5.6675% series bonds due 2012, requires that PGE maintain a common equity percentage of not less than 45%. The other agreement, which insures the $50 million of 5.279% series bonds due 2013, requires that PGE maintain a common equity percentage of not less than 42%. Under the latter agreement, the requirement does not apply as long as the Company maintains a rating on its senior secured debt of either BBB+ or higher by Standard and Poor's or Baa1 or higher by Moody's Investors Service. The Company was in compliance with the requirements of these agreements at December 31, 2007.

Pursuant to PGE's application, the Federal Energy Regulatory Commission (FERC) issued an order on January 17, 2008 which authorized the Company to issue short-term debt, including commercial paper, in an amount not to exceed $550 million outstanding at any one time, over the two-year period February 7, 2008 through February 6, 2010. The FERC's order extended and increased its previous authorization, which covered the period February 8, 2006 through February 7, 2008 and authorized the issuance of up to $400 million in short-term debt.

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 revolving credit facility. The amount available under the program is limited to the unused amount of credit under the facility. At December 31, 2007, PGE had no short-term commercial paper debt outstanding and had utilized approximately $14 million in letters of credit, with $386 million of remaining borrowing capacity available, compared to $313 million at December 31, 2006.

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

	December 31,		
	2007	**2006**	**2005**
Aggregate short-term debt outstanding - commercial paper	$ -	$ 81	$-
Weighted average interest rate* - commercial paper	-	5.5%	-

	Years Ended December 31,		
	2007	**2006**	**2005**
Average daily amounts of short-term debt outstanding - commercial paper	$ 22	$ 12	$-
Weighted daily average interest rate* - commercial paper	5.6%	5.1%	-
Maximum amount outstanding during the year	$ 93	$ 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.

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

	December 31, 2007	December 31, 2006
First Mortgage Bonds:		
Maturing 2007 - (7.15%)	$ -	$ 50
Maturing 2012 - (5.6675%)	100	100
Maturing 2013 - (5.279%-5.625%)	100	100
Maturing 2018 - (5.80%)	75	-
Maturing 2021 - 2033 (6.75%-9.31%)	120	120
Maturing 2031 - (6.26%)	100	100
Maturing 2036 - (6.31%)	175	175
Maturing 2037 - (5.81%)	130	-
Maturing 2039 - (5.80%)	170	-
Total First Mortgage Bonds	970	645
Pollution Control Revenue Bonds:		
Port of Morrow, Oregon, variable rate, due 2033 (5.20% fixed rate to 2009)	23	23
Port of Morrow, Oregon, variable rate, due 2031	6	-
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)	10	15
Total pollution control revenue bonds	195	194
Other:		
7.875% Notes due March 15, 2010	149	149
7.75% Series Cumulative Preferred Stock *	-	16
Unamortized debt discount	(1)	(1)
Total other	148	164
Total long-term debt	1,313	1,003
Current portion of long-term debt	-	(66)
Long-term debt, net of current portion	$1,313	$ 937

* The 7.75% Series Cumulative Preferred Stock (no par value), which was mandatorily redeemable, was classified as long-term debt in accordance with SFAS 150. The 159,727 shares outstanding at December 31, 2006 were redeemed in 2007.

Of the total principal amount of long-term debt outstanding as of December 31, 2007, $186 million is due and payable in 2010, with the balance of $1,127 million due and payable in various years beyond 2011. Interest on all debt listed in the table above is payable semi-annually, with the exception of the $6 million Port of Morrow Pollution Control Bonds, due in 2031, for which interest is payable monthly.

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), which are classified as trading and approximate fair value. These include the Nuclear decommissioning trust, Non-qualified benefit plan trust, and other miscellaneous financial instruments. Fair value of investments in marketable securities is based on quoted market prices.

Short term debt - Due to the short-term nature of the commercial paper, the fair value of such instruments approximates their book value.

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. At December 31, 2007, the estimated aggregate fair value of PGE's long-term debt approximated its $1,313 million carrying amount. At December 31, 2006, the estimated aggregate fair value of PGE's long-term debt was $1,046 million, compared to its $1,003 million carrying amount.

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. At December 31, 2007, these agreements, all of which expire at varying dates from 2008 to 2018, require payments of approximately $63 million in 2008, $24 million in 2009, $23 million in 2010, $18 million in 2011, $15 million in 2012, and $51 million over the remaining years of the contracts.

Purchase Commitments

Certain commitments have been made for capital and other purchases for 2008 and beyond. Such commitments total $171 million as of December 31, 2007, reflecting future payment requirements of $94 million in 2008, $54 million in 2009, $11 million in 2010, and $10 million in 2011, $1 million in 2012, and $1 million in 2013. Such commitments include those related to hydro license agreements, Biglow Canyon, Coyote Springs, upgrades to production and distribution facilities, Trojan and Bull Run decommissioning activities, information systems, 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 $15 million in 2008 and $3 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, 2007	$ 374	$257	$ 432	$ 198	$ 19
PGE's current share of:					
Output	12.0 %	6.5 %	18.7 %	19.4 %	100 %
Net capability (megawatts)	156	62	194	154	36
PGE's annual cost, including debt service:					
2007	$ 9	$ 3	$ 10	$ 8	$ 4
2006	9	3	8	7	4
2005	8	4	7	6	5
Contract expiration date	2011	*	*	2018	2017

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

PGE's annual share of debt service costs, excluding interest, is approximately $8 million in 2008, $9 million in 2009, $7 million in 2010 and 2011, and $5 million in 2012. Total minimum payments through the remainder of the contracts are estimated at $50 million.

Under contracts with the public utility districts, PGE has acquired a percentage of the output (Allocation) of the above four hydroelectric projects (the Rocky Reach, Priest Rapids, Wanapum and Wells hydroelectric projects). 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 the output and 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 that would not adversely affect the tax exempt status of any outstanding debt.

As of December 31, 2007, PGE has power purchase contracts with other counterparties, requiring payments of approximately $350 million in 2008, $161 million in 2009, $75 million in 2010, $74 million in 2011, $63 million in 2012, and $618 million over the remaining years of the contracts, which expire at varying dates from 2013 to 2035. PGE also has power capacity contracts as of December 31, 2007 that require payments of approximately $23 million annually from 2008 through 2012 and are expected to average approximately $19 million from 2013 through 2016. As of December 31, 2007, PGE has power sale contracts with other counterparties of approximately $164 million in 2008, $62 million in 2009, $5 million annually in 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. At December 31, 2007, PGE was owed 1,695 MWhs of electricity, all of which are expected to be delivered by the end of February 2008. The other exchange contract is with a winter-peaking

Northwest utility to help meet the Company's summer-peaking power requirements. At December 31, 2007, PGE owed 8,929 MWhs of electricity, all of which are expected to be delivered by the end of February 2008.

Leases

PGE has various operating leases associated with its headquarters and certain of its production, transmission, and support facilities. The majority of the future minimum lease payments presented in the table below consist of the corporate headquarters lease, which expires in 2018, but includes the renewal period options through 2043, and the Beaver generating plant land lease, which expires in 2096.

At December 31, 2007, future minimum payments under non-cancelable operating leases, net of sublease income, are as follows (in millions):

Years Ending December 31:	
2008	$ 8
2009	7
2010	7
2011	7
2012	8
Thereafter	220
Total	$257

Reflected in the table above is sublease income of $3 million in 2008 and 2009, $2 million in 2010 and 2011, and $1 million in 2012. Sublease income, which is classified as Miscellaneous in the Consolidated Statements of Income, was $3 million in 2007, 2006, and 2005.

Rent expense was $8 million in 2007, 2006, and 2005.

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 Purchaser under the lease. Assuming no recovery from the Utility and no reduction in damages from mitigating sales or leases related to the Boardman Assets and P&T Agreements, the maximum amount that would be owed by PGE in 2008 is approximately $168 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 based on PGE's historical experience and the evaluation of the specific indemnities. At December 31, 2007, management believes the likelihood is remote that PGE would be required to perform or otherwise incur any significant losses. The Company has not recorded any liability on the Consolidated Balance Sheets with respect to these indemnifications.

Note 10 - Price Risk Management

PGE utilizes derivative instruments, including forward, swap, and option contracts for electricity and natural gas, and futures contracts for natural gas, in its retail 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 133, derivative instruments are recorded at estimated fair value on the Balance Sheet as an asset or liability unless they qualify for the normal purchase, normal sale exception, with changes in estimated fair value recognized currently in earnings, unless specific hedge accounting criteria are met.

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 net income. The derivative instruments entered into to manage the Company's future retail resource requirements are subject to regulation; accordingly, the unrealized gains and losses are deferred pursuant to SFAS 71 in both net income and OCI.

Changes in the fair value of retail 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 Revenues, with purchases, natural gas swaps and futures recorded in Purchased power and fuel expense. PGE records the non-physical settlement of electricity derivative activities on a net basis in Purchased power and fuel expense, in accordance with EITF 03-11, as none of PGE's derivative activities are executed for trading 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.

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 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 referred to as "book outs." Only the net amount of those purchases or sales required to fulfill retail and wholesale obligations are physically settled.

The following table reflects unrealized gains and losses recorded in net income from derivative activities (in millions):

	Years Ended December 31,		
	2007	**2006**	**2005**
Unrealized gains (losses)	$ 26	$ (127)	$ 41
SFAS 71 regulatory asset (liability)	(26)	132	(37)
Net unrealized gains	$ -	$ 5	$ 4

The following table reflects, before income taxes, derivative activities from cash flow hedges recorded in OCI (in millions):

	Years Ended December 31,		
	2007	2006	2005
Unrealized holding net gains (losses)	$ (4)	$ (42)	$ 46
Reclassification to net income for contract settlements	3	(18)	7
Reclassification to net income due to discontinuance of cash flow hedges *	-	-	(2)
Reclassification of unrealized (gains) losses to SFAS 71 regulatory asset (liability)	1	61	(48)
Net unrealized gains on cash flow hedges recorded in OCI	$ -	$ 1	$ 3

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

Hedge ineffectiveness from cash flow hedges was not material in 2007, 2006, and 2005. Additionally, in 2007, PGE elected to discontinue hedge accounting for the Company's remaining outstanding derivatives designated as cash flow hedges, in accordance with SFAS 133. This resulted in less than $0.5 million remaining in OCI until settlement. As of December 31, 2007, the transactions with associated amounts held in OCI will settle over the next 45 months. The Company estimates that of the $4 million of net unrealized gains in OCI at December 31, 2007, $3 million in net unrealized gains will be reclassified into earnings within the next twelve months (fully offset by SFAS 71 regulatory assets) and $1 million in net unrealized gains will be reclassified over the remaining 33 months (fully offset by SFAS 71 regulatory liabilities).

As indicated above, PGE discontinued its non-retail electricity trading activities in early 2005. All unrealized and realized gains and losses associated with such transactions were reported on a net basis. During 2005, unrealized losses of $1 million and realized gains of $1 million on electricity and natural gas trading activities were included in Revenues. Transaction volumes under electricity trading contracts that settled during 2005 totaled 815,000 MWhs purchased and sold.

Note 11 - Jointly-Owned Plant

At December 31, 2007, PGE had the following investments in jointly-owned plant (dollars in millions):

Facility	Ownership Percent	In-service Date	Cost	Accumulated Depreciation *	Construction Work In Progress
Boardman	65.00	1980	$ 422	$264	$ 3
Colstrip 3 and 4	20.00	1986	488	302	1
Pelton/Round Butte	66.67	1958/1964	116	45	31
Total			$1,026	$611	$35

* Excludes Asset Retirement Obligations and Accumulated Asset Retirement Removal Costs.

The above amounts represent PGE's share of jointly-owned plant, with the Company's share of both direct expenses and utility plant costs included in its financial statements. Each joint owner has provided its own financing.

Note 12 - Asset Retirement Obligations

Under SFAS 143 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 Consolidated Statements of Income, amounts are included in Depreciation and amortization expense for Electric 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 in prices charged to customers. Any differences in the timing of recognition of costs for financial reporting and ratemaking purposes are deferred as a regulatory asset or regulatory liability under SFAS 71. Substantially all significant AROs are included in rate regulation, and PGE expects any changes in estimated AROs to be incorporated in future prices.

Recognized Asset Retirement Obligations - At December 31, 2007, PGE's AROs associated with Trojan totaled $62 million, representing the present value of future decommissioning expenditures. In 2007, PGE reduced the estimated Trojan ARO to reflect the settlement of demolition activities, reduce the estimated annual cash flows related to the ISFSI operation until final decommissioning, and adjust for certain other decommissioning activities. Demolition activity, which is nearly complete, is expected to continue through 2008, with final demolition and site restoration activities expected to occur at the end of the decommissioning period. For further information related to Trojan decommissioning, see Note 13.

Site specific AROs, totaling $18 million, have 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, Biglow Canyon Phase I, and the Bull Run hydro project. A $2 million conditional ARO, 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 is a summary of the changes in the Company's AROs (in millions):

	Years Ended December 31,		
	2007	**2006**	**2005**
Balance at beginning of year	$134	$134	$120
AROs incurred	7	-	2
Expenditures	(9)	(6)	(4)
Accretion	7	7	6
Revisions	(48)	(1)	10
Balance at end of year	$ 91	$134	$134

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 if and 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 by 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 - Remaining activities consist of the demolition of certain structures and long-term operation and decommissioning of the ISFSI. Final site restoration activities are expected to begin following shipment of spent fuel to a U.S. Department of Energy (USDOE) facility (see "Nuclear Fuel Disposal and Cleanup of Federal Plants" below).

The Trojan decommissioning plan includes an estimate of PGE's cost to decommission the plant. The original cost estimate, based upon a site-specific engineering study, is periodically revised and updated to reflect actual costs and changes in estimates. A probability weighting was applied to the decommissioning cost estimate to account for the possibility of a five-year delay in the shipment of the spent fuel to a USDOE facility, with final shipment estimated to occur between 2030 and 2035.

The following is the activity for the Trojan ARO for the periods presented (in millions):

	Years Ended December 31,	
	2007	**2006**
Balance at beginning of year	$108	$107
Expenditures	(4)	(5)
Accretion	6	6
Revisions	(48)	-
Balance at end of year	$ 62	$108
Total expenditures to date	$218	$215

PGE's retail prices include the recovery of decommissioning costs, with an equal amount recorded in amortization expense. Due to revised estimates, the recovery period was extended from 2011 through 2014, with annual recovery reduced from $14 million to $4.65 million. Such reduction is reflected in prices that became effective on January 17, 2007, as authorized by the OPUC.

Amounts collected from customers 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. Decommissioning trust funds are invested in a diversified portfolio of fixed income securities, with year-end balances 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.

The following is the activity for the Nuclear decommissioning trust for the periods presented (in millions):

	Years Ended December 31,	
	2007	2006
Balance at beginning of year	$42	$31
Contributions	5	14
Earnings	3	1
Disbursements	(4)	(4)
Balance at end of year	$46	$42

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. The Company is working with the OPUC to determine the appropriate timing of such refunds to 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 2017.

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 25 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 to occur between the years 2030 and 2035. 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 USDOE has proposed that a Transfer, Aging, and Disposal canister-based system (TAD) be required for commercial spent nuclear fuel disposal in their draft license application for the Monitored Geologic Repository (Yucca Mountain). The TAD would be the first element of an integrated three-canister system to provide containment, strength, and corrosion resistance to the disposal package. The USDOE expects each utility to purchase the TAD and pay for the repackaging of existing transportable fuel containers (such as PGE's system) at the planned wet-handling facility at Yucca Mountain. The additional costs and the timing of when the proposed USDOE requirements may become final are not known at this time.

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 were 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. A bill was introduced in the U.S. Senate in October 2007 to reinstate the fund. If passed, it would require that $2.25 billion be paid by U.S. utilities over a ten-year period. The potential impact to PGE remains uncertain at this time.

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.

Note 14 - Contingencies

Legal Matters

Trojan Investment Recovery - In 1993, PGE closed the Trojan Nuclear Plant as part of the Company's least cost planning process. PGE sought full recovery of, and a rate of return on, its Trojan plant costs, 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 Oregon 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. The 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 Corp. 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 prices 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.

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 prices 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. On October 10, 2007, the Oregon Court of Appeals issued an opinion that vacated the 2003 Remand and remanded the 2002 Order to the OPUC for reconsideration.

Prior to the October 10, 2007 opinion of the Court of Appeals, the OPUC combined the 1998 Remand and the 2003 Remand into one proceeding and has been considering the matter in two phases. The first phase involves a determination of what prices would have been if, in 1995, the OPUC had interpreted the law to prohibit a return on the Trojan investment. The second phase involves a determination of whether the OPUC has authority to engage in retroactive ratemaking.

In Order No. 07-157 (the Order), entered on April 19, 2007, the OPUC denied the motion PGE filed in November 2006 to consolidate phases and re-open the record. In addition, the Order abated the first phase of the proceeding pending a decision by the Oregon Court of Appeals on the 2003 Remand, and ordered that the second phase of the remand proceeding be immediately commenced to investigate the OPUC's authority to engage in retroactive ratemaking. The Order further stated that parties not now participating in the joint remand proceedings will be allowed to intervene and participate in the second phase. Oral argument was held on August 9, 2007.

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 plus interest for the Current Class and $70 million plus interest for the Former Class, as a result of the inclusion of a return on investment of Trojan in the prices 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 price reductions or refunds, for any amount of return on the Trojan investment PGE collected in prices 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, but inviting motions to lift the abatement after one year. On October 17, 2007, the plaintiffs filed a motion to lift the abatement. A hearing on that motion is scheduled for April 2008. On January 14, 2008, the class action plaintiffs filed a motion asking the OPUC to issue an order on the OPUC remedial authority prior to addressing the other issues and the Utility Reform Project requested permission to address all issues it previously raised on appeal to the Circuit Court and on cross-appeal to the Court of Appeals in URP, et al. v. PUC, with an opportunity to present new evidence with full evidentiary hearings. On February 13, 2008, the OPUC issued an order denying this motion. In the order, the OPUC expressed its desire to avoid future piecemeal litigation by resolving all of these issues in one comprehensive order, including the issue of the OPUC's remedial authority. The OPUC further stated that it has come to the preliminary conclusion that the OPUC has refund authority under limited circumstances. The OPUC emphasized that this is a preliminary determination and stated that it has not yet determined whether it is necessary to exercise that authority in this case and that it cannot make such a determination until it has decided all phases of the proceedings. On February 22, 2008, the Administrative Law Judge issued a Ruling and Notice of Conference, which established the scope for further proceedings prior to issuance of the OPUC order. The ruling also includes notice of a conference scheduled for March 12, 2008 to establish a procedural schedule for the remainder of this phase of the proceeding.

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.

Regulatory Matters

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 (Colstrip), 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. On September 12, 2007, the Interior Board of Land Appeals issued a decision affirming the March 28, 2005 MMS decision. WECO has filed a Complaint for Declaratory and Injunctive Relief with the U.S. District Court for the District of Columbia challenging the decision of the Interior Board of Land Appeals.

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 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 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, PGE 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 likely seek recovery through the ratemaking process.

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

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

The settlement between PGE and certain other parties in the California refund case in Docket No. EL00-95, (California Refund case) et seq., approved by the FERC on May 17, 2007, resolves all claims as between PGE and the California parties named in the settlement as to transactions in the Pacific Northwest during the settlement period, January 1, 2000 through June 21, 2001, but does not settle potential claims from other market participants relating to transactions in the Pacific Northwest.

In a separate action, on March 20, 2002, the California Attorney General filed a complaint (the Lockyer case) with the FERC against various sellers in the wholesale power market, alleging that the FERC's authorization of market-based rates violated the Federal Power Act (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. Petitions for rehearing at the Ninth Circuit and for U.S. Supreme Court review have been denied and the case has been remanded to the FERC.

On December 10, 2007, certain California parties filed with the FERC a Motion to hold the Lockyer case remand proceedings in abeyance until the court issues mandates in the California Refund case and Northwest Refund case. In their Motion, the California parties argue that all three cases include similar parties and similar issues, particularly the impact of alleged market manipulation in western energy markets during the 2000-2001 time period. They assert that these cases should be considered together by FERC and that they will file a motion to consolidate all three cases upon remand of the two that remain pending before the Ninth Circuit. The Company and other parties filed answers contesting the California parties' characterization of the three cases as inextricably linked and arguing that it is premature to discuss consolidation. Consolidation of the Lockyer case with the Northwest Refund case and the California Refund case could increase the Company's potential liability by extending the period for which other parties are requesting refunds back to May 1, 2000 or earlier.

Management cannot predict the outcome of these proceedings or whether the FERC will order refunds retroactively to May 1, 2000 or earlier, and if so, how such refunds would be calculated. However, management 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.

Complaint and Application for Deferral - Income Taxes - On October 5, 2005, the URP and Ken Lewis (together, the Complainants) filed a Complaint and an Application for Deferred Accounting with the OPUC alleging that, since the September 2, 2005 effective date of Oregon Senate Bill 408 (SB 408), PGE's rates were not just and reasonable and were in violation of SB 408 because they contained approximately $92.6 million in annual charges for state and federal income taxes that are not being paid to any governmental entity. The Complaint and Application for Deferred Accounting requested that the OPUC order the creation of a deferred account for all amounts charged to customers since September 2, 2005 for state and federal income taxes, less amounts actually paid by or on behalf of PGE to the federal and state governments for income taxes. PGE contended that no adjustment for taxes may be made prior to the January 1, 2006 effective date of the automatic adjustment clause included in SB 408. For further information, see Note 15, Utility Rate Treatment of Income Taxes.

On August 14, 2007, the OPUC issued an order granting the Application for Deferred Accounting for the period from October 5, 2005 through December 31, 2005 (Deferral Period). The OPUC's order also dismissed the Complaint, without prejudice, on grounds that it was superfluous to the Complainants' request for deferred accounting. The order required that PGE calculate the amounts applicable to the Deferral Period, along with calculations of PGE's earnings and the effect of the deferral on the Company's return on equity. The order also provided that the OPUC would review PGE's earnings at the time it considers amortization of the deferral. PGE understands that the OPUC will consider the potential impact of the deferral on PGE's earnings over a relevant twelve-month period, which will include the Deferral Period. On October 15, 2007, PGE filed a petition for judicial review with the Oregon Court of Appeals, seeking review of the OPUC's August 14, 2007 order. The Court of Appeals granted PGE's motion to stay the proceedings until April 15, 2008.

On December 1, 2007, PGE filed its report as required by the OPUC. In the report, PGE determined that the amount of any deferral would be between zero and $26.6 million, that a relevant 12-month period would be the 12-month period ending September 30, 2006, and that PGE's earnings over such period would preclude any refund. After consideration of these matters, the OPUC will determine whether a rate adjustment is required. The OPUC decision is expected prior to June 1, 2008.

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

Environmental Matters

Harborton - Since 1973, PGE has operated the Harborton Substation on land owned by the Company located near the Willamette River. A 1997 investigation by the Environmental Protection Agency (EPA) of a 5.5 mile segment of the 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 companies in addition to PGE 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 Substation site to the Oregon Department of Environmental Quality (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 that the Harborton Substation site does not appear to be a current source of contamination to the river.

In a 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.

On January 22, 2008, PGE received a Section 104e Information Request from the EPA requiring the Company to provide information concerning its properties in or near the Portland Harbor Superfund Site as well as several miles beyond the initial 5.5 mile segment of the river. PGE's response is due May 16, 2008.

Sufficient information is currently not available to determine the total cost of any required investigation or remediation of the Portland Harbor 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 condition, results of operations or cash flows.

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, 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 (RI/FS) from the EPA, dated June 27, 2005, in which the Company was named as one of fourteen PRPs with respect to the Harbor Oil site. The letter started a period for the PRPs to participate in negotiations with the EPA to reach a settlement to conduct or finance an RI/FS of the Harbor Oil site. On May 31, 2007, an Administrative Order on Compliance was signed by the EPA and six other parties, including PGE, to implement an RI/FS at the Harbor Oil site. The final revised work plan for the RI/FS has been submitted to the EPA. Site access agreements are being negotiated with surrounding properties and the site operator. On-site sampling is expected to begin in the first quarter of 2008.

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

General

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

Note 15 - Utility Rate Treatment of Income Taxes

An Oregon 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 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 to taxes paid to units of government and collected from customers on or after January 1, 2006.

The rules adopted by the OPUC to implement SB 408 include the use of fixed reference points for margins and effective tax rates from a ratemaking proceeding. The rules also include 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, beginning January 1, 2006, interest is to accrue on the differences between income taxes collected and income taxes paid to governmental entities, using a mid-year convention.

The following table summarizes the estimated amounts recorded in PGE's consolidated financial statements as a SB 408 regulatory asset or (liability) for the 2007 and 2006 reporting years (in millions):

	Reporting Year	
	2007	**2006**
Balance as of December 31, 2005	$ -	$ -
Accrued refunds	-	(40)
Accrued interest income (expense)	-	(2)
Balance as of December 31, 2006	-	(42)
Accrued collections	15	-
Accrued interest income (expense)	1	(3)
Adjustments	-	3
Balance as of December 31, 2007	$16	$(42)

2006 Reporting Year

PGE filed its report on October 15, 2007 with the OPUC reflecting the amount of taxes paid by the Company, as well as the amount of taxes authorized to be collected in rates. The report is being reviewed as part of a formal process, with the OPUC expected to issue an order in April 2008. The Company has reached agreement with OPUC Staff and certain interveners that the appropriate refund due customers is $37.2 million plus accrued interest, based on the OPUC's administrative rules that govern the calculation of the refund amount. This regulatory liability includes $17 million paid to Enron Corp. for net current taxes payable for the first quarter of 2006 when PGE was included in its former parent's consolidated group for filing consolidated federal and state income tax returns. Under OPUC rules, refunds to customers for the 2006 reporting year will begin on June 1, 2008.

Under SB 408 rules, each utility is required to obtain a Private Letter Ruling (PLR) from the Internal Revenue Service (IRS) on whether the utility's compliance with SB 408 law or rules would cause the utility to fail to comply with provisions of federal tax law related to normalization requirements. PGE received its PLR from the IRS on January 18, 2008 indicating that the Company's compliance with SB 408 law or rules does not appear to cause normalization violations.

2007 Reporting Year

PGE has recorded an estimated $16 million collection from customers (including $1 million of accrued interest) related to the year 2007. Any collections from, or refunds to, customers for the 2007 tax year will be reported to the OPUC by October 15, 2008. Any collections from customers for the 2007 reporting year will begin on June 1, 2009.

Note 16 - Related Party Transactions

Prior to April 3, 2006, PGE was a wholly-owned subsidiary of Enron and was included in Enron's consolidated income tax return. Pursuant to this relationship, PGE was billed for a portion of Enron's costs incurred related to the resolution of issues associated with Enron's bankruptcy and litigation related to certain employee benefit plans in which PGE employees previously participated. Additionally, PGE made payments to Enron for PGE's income tax liabilities.

During 2006, PGE recognized a reduction of $1 million in Administrative and other expense related to the final resolution of costs billed by Enron in 2005 for issues associated with its bankruptcy and litigation related to employee benefit plan matters described above and paid Enron $17 million for its current income taxes payable for the first quarter of 2006. At December 31, 2006, PGE had no outstanding amounts due to Enron.

During 2005, PGE recognized $7 million for insurance coverage and costs related to the employee benefit matters described above.

QUARTERLY FINANCIAL DATA (Unaudited)

	Quarter Ended			
	March 31	**June 30**	**September 30**	**December 31**
	(In millions, except per share amounts)			
2007				
Revenues	$ 436	$ 402	$ 435	$ 470
Income from operations (a)	64	56	35	43
Net income (a)	55	46	20	24
Earnings per share - basic and diluted (c)	$ 0.88	$ 0.73	$ 0.32	$ 0.40
2006				
Revenues	$ 381	$ 351	$ 372	$ 416
Income from operations (b)	6	41	20	54
Net income (loss) (b)	(6)	27	10	40
Earnings (loss) per share - basic and diluted (c)	$ (0.10)	$ 0.43	$ 0.16	$ 0.64

(a) Operating results for the first quarter of 2007 include the approximate $13 million after-tax effect of the deferral of a portion of Boardman replacement power costs for future rate recovery (as approved by the OPUC) and the approximate $4 million after-tax effect of the settlement between PGE and certain California parties related to wholesale energy transactions in the western energy markets during 2000-2001.

(b) Operating results for the first quarter of 2006 include the approximate $26 million after-tax effect of excess power costs incurred to replace the output of the Boardman coal plant, which was taken out of service for repair of the plant's steam turbine rotor on October 22, 2005, and which remained out of service for most of the first half of 2006. For further information, see Results of Operations 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 approximate $13 million after-tax effect of a reserve for a refund obligation to customers related to PGE's estimate of the impact of SB 408. For further information, see Note 15, Utility Rate Treatment of Income Taxes, in the Notes to Consolidated Financial Statements.

(c) Earnings per share are calculated independently for each period 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, 2007, the Company's internal control over financial reporting is effective.

The Company's internal control over financial reporting, as of December 31, 2007, has been audited by Deloitte & Touche LLP, the independent registered public accounting firm who audits the Company's consolidated financial statements, as stated in their report included in Item 8. - "Financial Statements and Supplementary Data," which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting, as of December 31, 2007.

(c) **Changes in Internal Control over Financial Reporting**

There have not been any changes in the Company's internal control over financial reporting during the fourth quarter of 2007 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Item 9B. Other Information

None.

Part III

Item 10. Directors 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," "Proposal 1: Election of Directors - The Board of Directors," and "Executive Officers" in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the Securities and Exchange Commission in connection with the Annual Meeting of Shareholders to be held on May 7, 2008.

The information required to be furnished pursuant to this item with respect to the identification of the Audit Committee, the Audit Committee financial experts, 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 7, 2008.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information required by Item 12 is incorporated herein by reference to the relevant information under the captions "Security Ownership of Certain Beneficial Owners, Directors and Executive Officers" and "Equity Compensation Plans," in the Company's definitive proxy statement to be filed pursuant to Regulation 14A with the Securities and Exchange Commission in connection with the Annual Meeting of Shareholders to be held on May 7, 2008.

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 7, 2008.

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 7, 2008.

Part IV

Item 15. Exhibits, Financial Statement Schedules

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

Exhibits

See Exhibit Index on Page 116 of this report.

Portland General Electric Company and Subsidiaries
Schedule II - Consolidated Valuation and Qualifying Accounts
For the Years Ended December 31, 2007, 2006, and 2005
(In millions)

	Allowance for Uncollectible Accounts
Balance at January 1, 2005	$ 50
Provision charged to income	7
Amounts written off, less recoveries	(7)
Balance at December 31, 2005	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
Provision charged to income	6
Settlement of California Refund Case	(40)
Amounts written off, less recoveries	(6)
Balance at December 31, 2007	$ 5

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

February 27, 2008

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)	February 27, 2008
/s/ JAMES J. PIRO James J. Piro	Executive Vice President, Finance Chief Financial Officer and Treasurer (principal financial and accounting officer)	February 27, 2008
* John W. Ballantine	Director	February 27, 2008
* Rodney L. Brown, Jr.	Director	February 27, 2008
* David A. Dietzler	Director	February 27, 2008
* Mark B. Ganz	Director	February 27, 2008
* Corbin A. McNeill, Jr.	Director	February 27, 2008
* Neil J. Nelson	Director	February 27, 2008
* M. Lee Pelton	Director	February 27, 2008
* Maria M. Pope	Director	February 27, 2008
* Robert T.F. Reid	Director	February 27, 2008

*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	*	Fifty-sixth Supplemental Indenture dated May 1, 2006 [Form 8-K filed May 25, 2006, Exhibit (4)].
4.4	*	Fifty-seventh Supplemental Indenture dated December 1, 2006 [Form 8-K filed December 21, 2006, Exhibit (4)].
4.5	*	Fifty-eighth Supplemental Indenture, dated April 1, 2007 [Form 8-K filed April 12, 2007, Exhibit (4)].
4.6	*	Fifty-ninth Supplemental Indenture, dated October 1, 2007 [Form 8-K filed October 5, 2007, Exhibit (4)].
		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)].

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES

EXHIBIT INDEX

Number		Exhibit
		Executive Compensation Plans and Arrangements:
10.16	*	Portland General Electric Company Severance Pay Plan for Executive Employees, dated June 15, 2005 [Form 8-K filed June 20, 2005, Exhibit (10.1)].
10.17	*	Portland General Electric Company Outplacement Assistance Plan, dated June 15, 2005 [Form 8-K filed June 20, 2005, Exhibit (10.2)].
10.18	*	Portland General Electric Company 2005 Management Deferred Compensation Plan, dated March 4, 2005 [Form 10-K filed March 11, 2005, Exhibit (10)].
10.19	*	Portland General Electric Company Management Deferred Compensation Plan, dated March 12, 2003 [Form 10-Q filed May 15, 2003, Exhibit (10.1)].
10.20	*	Portland General Electric Company Supplemental Executive Retirement Plan, dated March 12, 2003 [Form 10-Q filed May 15, 2003, Exhibit (10.2)].
10.21	*	Portland General Electric Company Senior Officers' Life Insurance Benefit Plan, dated March 12, 2003 [Form 10-Q filed May 15, 2003, Exhibit (10.3)].
10.22	*	Portland General Electric Company Umbrella Trust for Management, dated March 12, 2003 [Form 10-Q filed May 15, 2003, Exhibit (10.4)].
10.23		Portland General Electric Company 2006 Stock Incentive Plan, as amended.
10.24	*	Portland General Electric Company 2006 Annual Cash Incentive Master Plan [Form 8-K filed March 17, 2006, Exhibit (10.1)].
10.25	*	Portland General Electric Company 2006 Outside Directors' Deferred Compensation Plan [Form 8-K filed May 17, 2006, Exhibit (10.1)].
10.26	*	Portland General Electric Company 2007 Employee Stock Purchase Plan (Appendix B to Proxy Statement filed March 30, 2007).
10.27	*	Form of Directors' Restricted Stock Unit Agreement [Form 8-K filed July 14, 2006, Exhibit (10.1)].
10.28	*	Form of Officers' Performance Stock Unit Agreement [Form 8-K filed July 14, 2006, Exhibit (10.2)].
10.29	*	Portland General Electric Company 2008 Annual Cash Incentive Master Plan for Executive Officers [Form 8-K filed February 26, 2008, Exhibit (10.1)].

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES

EXHIBIT INDEX

Number	Exhibit
(12)	**Statements Re Computation of Ratios**
12.1	Computation of Ratio of Earnings to Fixed Charges.
(23)	**Consents of Experts and Counsel**
23.1	Consent of Independent Registered Public Accounting Firm Deloitte & Touche LLP.
(24)	**Power of Attorney**
24.1	Power of Attorney.
(31)	**Rule 13a-14(a)/15d-14(a) Certifications**
31.1	Certification of Chief Executive Officer.
31.2	Certification of Chief Financial Officer.
(32)	**Section 1350 Certifications**
32	Certifications of Chief Executive Officer and Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

*** Incorporated by reference as indicated.**

Note: The Exhibits filed or 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