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

FORM 10-K

[X] **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2005
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
None	

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

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

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

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

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

Indicate by check mark 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. [X]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer [ ] Accelerated filer [ ] Non-accelerated filer [X]

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

State the aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter: $0.

Number of shares of Common Stock outstanding as of February 28, 2006: 42,758,877 shares of common stock, $3.75 par value. (All shares are owned by Enron Corp.)

DEFINITIONS

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

Abbreviations or Acronyms	
AFDC	Allowance For Funds Used During Construction
Bankruptcy Court	United States Bankruptcy Court for the Southern District of New York
Beaver	Beaver Combustion Turbine Plant
Boardman	Boardman Coal Plant
BPA	Bonneville Power Administration
Chapter 11 Plan	Fifth Amended Joint Plan of Affiliated Debtors Pursuant to Chapter 11 of the United States Bankruptcy Code, dated January 9, 2004 and as thereafter amended and supplemented from time to time
Colstrip	Colstrip Units 3 and 4 Coal Plant
Coyote Springs	Coyote Springs Unit 1 Generating Plant
CUB	Citizens' Utility Board
Debtors	Enron Corp. and its reorganized debtor subsidiaries under the Chapter 11 Plan
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
ESS	Energy Service Supplier
EPAct 2005	Energy Policy Act of 2005
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	Environmental Protection Agency
ERISA	Employee Retirement Income Security Act of 1974
ESA	Endangered Species Act
FERC	Federal Energy Regulatory Commission
Financial Statements	Consolidated Financial Statements of Portland General Electric Company included in Part II, Item 8 of this report
IRS	Internal Revenue Service
kWh	Kilowatt-hour

DEFINITIONS

Abbreviations or Acronyms	
MW	Megawatt
MWa	Average megawatts
MWh	Megawatt-hour
NRC	Nuclear Regulatory Commission
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange, Inc.
OPUC or the Commission	Public Utility Commission of Oregon
PBGC	Pension Benefit Guaranty Corporation
PGE or the Company	Portland General Electric Company
PUHCA 1935	Public Utility Holding Company Act of 1935
PUHCA 2005	Public Utility Holding Company Act of 2005
RVM	Resource Valuation Mechanism
SEC	Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board
Trojan	Trojan Nuclear Plant
URP	Utility Reform Project
USDOE	United States Department of Energy
VEBA	Voluntary Employee Beneficiary Association
WECC	Western Electricity Coordinating Council

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Part I

Item 1. Business

General

PGE, incorporated in 1930, is a single, integrated electric utility engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the State of Oregon. PGE also sells electricity and natural gas in the wholesale market to utilities and power marketers located throughout the western United States. PGE's service area is located entirely within Oregon and includes 52 incorporated cities, of which Portland and Salem are the largest, within a state-approved service area allocation of approximately 4,000 square miles. PGE estimates that at the end of 2005 its service area population was approximately 1.5 million, comprising about 43% of the state's population. The Company added approximately 13,000 retail customers during 2005, and at December 31, 2005 served approximately 780,000 retail customers.

On July 2, 1997, Portland General Corporation (PGC), the former parent of PGE, merged with Enron Corp., with Enron continuing in existence as the surviving corporation and PGE operating as a wholly owned subsidiary of Enron. On December 2, 2001, Enron, along with certain of its subsidiaries, filed to initiate bankruptcy proceedings under Chapter 11 of the federal Bankruptcy Code. PGE was not included in the filing. For further information, see "Enron Bankruptcy" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

In accordance with the 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 (Chapter 11 Plan), Enron plans to distribute PGE common stock to creditors of Enron and its reorganized debtor subsidiaries (Debtors) holding allowed claims. Current PGE common stock will be cancelled and 62,500,000 shares of new PGE common stock without par value will be distributed over time to the Debtors' creditors. Initially, PGE will issue at least 30 percent of the new PGE common stock to Debtors' creditors holding allowed claims, with the remainder issued to a Disputed Claims Reserve (the DCR) where it will be held to be released over time to the Debtors' creditors holding allowed claims in accordance with the Chapter 11 Plan. Following the issuance of the new PGE common stock, expected to take place on or about April 3, 2006, PGE will no longer be a subsidiary of Enron. Distribution of new PGE common stock has been approved by the required regulatory agencies, including the OPUC and the FERC. However, the City of Portland, Oregon has appealed the OPUC decision to the Marion County Circuit Court and the Oregon Court of Appeals, and the Utility Reform Project has filed a motion for reconsideration by the OPUC. For further information, see "Future Ownership of PGE" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

As of December 31, 2005, PGE had 2,620 employees. This compares to 2,644 and 2,687 employees at December 31, 2004 and 2003, respectively. A total of 846 employees are covered under agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 829 employees for a five-year period effective from March 1, 2004 through February 28, 2009. In addition, 17 employees at Coyote Springs are covered under an agreement effective from September 1, 2001 through August 1, 2006.

Customers and Operating Revenues

Retail

PGE serves a diverse retail customer base. Residential, the largest customer class, comprises about 88% of the Company's total number of customers, with the remainder comprised largely of commercial customers. At year-end 2005, PGE served 257 large commercial and industrial customers. Residential demand is sensitive to the effects of weather, with revenues highest during the winter heating season. Commercial and industrial customer classes are not dominated by any single industry. While the 20 largest customers constitute about 13% of total retail revenues, they represent 9 different commercial and industrial groups, including high technology, paper manufacturing, metal fabrication, communications, health services, and governmental agencies. No single customer represents more than 5% of PGE's total retail load or 4% of total retail revenues.

Total retail revenues and MWh energy sales decreased from 2004, reflecting both a decrease in amounts recovered from customers related to power cost adjustment mechanisms in effect in prior years, as well as an increase in commercial and industrial customers who have chosen to purchase their energy requirements from electricity service suppliers (ESSs). PGE continues to serve these customers by delivering the energy purchased from ESSs. These decreases were partially offset by a 2005 price adjustment to reflect an increase in variable power costs. For further information, see "Results of Operations" and "Resource Valuation Mechanism" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

Wholesale (Non-Trading)

PGE participates in the wholesale marketplace in order to balance its supply of power to meet the needs of its retail customers, manage risk, and administer its current long-term wholesale contracts. Such participation includes power purchases and sales resulting from economic dispatch decisions for its own generation, which allows PGE to secure reasonably priced power for its customers. Interconnected transmission systems in the western states serve utilities with diverse load requirements, which allows the Company to purchase and sell electricity within the region depending upon the relative price and availability of power, water conditions, and seasonal demand.

Non-trading wholesale electricity sales related to activities to serve retail load requirements comprised about 8% and 7% of total operating revenues in 2005 and 2004, respectively. Most of PGE's non-trading wholesale sales are to utilities and power marketers and are predominantly short-term. The Company may net purchases and sales with the same counterparty rather than simultaneously receiving and delivering physical power. These net transactions are also referred to as "book outs." Only the net amount of those purchases or sales required to fulfill retail and wholesale obligations are physically settled.

Other Operating Revenues

Other operating revenues includes 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. PGE's energy trading activities, results of which were reflected in Other operating revenues, were discontinued in early 2005.

The following table summarizes Operating Revenues and Energy Sold and Delivered for the years indicated.

	2005		2004		2003	
	Amount	%	Amount	%	Amount	%
Operating Revenues (Millions)						
Retail Sales						
Residential	$ 593	46%	$ 585	46%	$ 555	43%
Commercial	505	40%	502	40%	500	39%
Industrial	178	14%	176	14%	228	18%
Total - Retail Sales	1,276		1,263		1,283	
Direct Access Customers [a]						
Commercial	1	-	2	-	-	-
Industrial	-	-	5	-	-	-
Tariff Revenues	1,277	100%	1,270	100%	1,283	100%
Accrued Revenues	28		48		45	
Total Retail Revenues	1,305		1,318		1,328	
Wholesale (Non-Trading) [b]	116		107		393	
Other Operating Revenues:						
Trading Activities - net	-		1		2	
Other	25		28		29	
Total Operating Revenues	$ 1,446		$ 1,454		$ 1,752	
Energy Sold and Delivered						
(Thousands of MWhs)						
Retail Energy Sales						
Residential	7,323	39%	7,270	39%	7,099	39%
Commercial	7,069	38%	7,247	39%	7,190	39%
Industrial	3,148	17%	3,247	18%	4,137	22%
Total - Retail Energy Sales	17,540		17,764		18,426	
Delivered to Direct Access Customers[a]						
Commercial	400	2%	159	1%	-	-
Industrial	814	4%	617	3%	-	-
Total Retail Energy Deliveries	18,754	100%	18,540	100%	18,426	100%
Wholesale (Non-Trading) [b]	2,094		2,539		9,966	
Trading Activities	815		9,699		13,551	
Total Energy Sold and Delivered	21,663		30,778		41,943	

(a) Under Oregon's electricity restructuring law, certain commercial and industrial customers have chosen to be served by an ESS for their energy needs, beginning in 2004. Although the energy is purchased from an ESS, PGE delivers the energy to these customers and bills them a distribution service charge. Retail revenue can fluctuate for Direct Access Customers as a result of "transition adjustments" reflecting the difference between the cost and market of PGE's power supply portfolio.

(b) Wholesale (Non-Trading) revenues and energy sales indicated above exclude those activities that were "booked out" (not physically settled), reflecting requirements of EITF 03-11, which became effective on October 1, 2003. Excluded amounts are $536 million and 9,523 thousand MWhs for 2005, $296 million and 6,802 thousand MWhs for 2004, and $90 million and 2,116 thousand MWhs for the fourth quarter of 2003 (prior periods were not reclassified). For further information, see Note 1, Summary of Significant Accounting Policies, in the Notes to Financial Statements.

For further information on year-to-year revenue trends, see Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

Regulation

General

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

Certain activities of PGE are also subject to the jurisdiction of the FERC. The Company is a "licensee" and a "public utility," as those terms are used in the Federal Power Act, and is subject to regulation by the FERC as to accounting policies and practices, licensing of hydroelectric projects, transmission services, wholesale sales, issuance of short-term debt, and other matters. In addition, PGE's interest in a natural gas pipeline is subject to the FERC's jurisdiction. Under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978, the FERC's authority includes matters related to extension, enlargement, safety, and abandonment of jurisdictional pipeline facilities, as well as transportation rates and accounting for interstate natural gas commerce. The Energy Policy Act of 2005 (EPAct 2005) expanded the FERC's authority with respect to holding companies, effective February 8, 2006. The FERC now has new authority to review proposed mergers and acquisitions to prevent cross-subsidization and the encumbrance of utility assets, as necessary for the protection of utility customers. As a subsidiary of a registered holding company (Enron), PGE had been subject to regulation by the SEC with respect to several activities under PUHCA 1935, which has now been repealed. For further information, see "Energy Policy Act of 2005" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

Construction of new thermal generating facilities requires a permit from the EFSC.

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

Regulatory Matters

Retail Customer Choice Program

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

In 2005, the three ESSs registered to transact business with PGE served a total of 25 customers with a total average load of approximately 150 MWa, representing about 11% of PGE's non-residential load and 7% of the Company's total retail load. In addition, a total of 59 commercial and industrial customers were receiving service from PGE under market-based pricing options at the end of 2005. Approximately 40,000 customers have chosen renewable energy options and approximately 1,800 customers have chosen the time of use option.

PGE also offers an option by which certain large non-residential customers may, for a minimum three-year or five-year term, elect to be removed from cost of service pricing, with energy supplied by an ESS or at a daily market rate by PGE. Two customers, with a load of approximately 10 MWa, have chosen the five-year option; one began receiving service from PGE in 2003 and the other began receiving service from an ESS in 2004.

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

In accordance with the restructuring law and an order from the OPUC, PGE deferred certain costs related to implementation of the restructuring plan for recovery in electricity prices. Recovery of these costs is continuing, with unrecovered costs totaling approximately $16 million at December 31, 2005.

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

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

Federal Wholesale and Transmission Regulation

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

In 1999, the FERC issued Order No. 2000 in a continued effort to more efficiently manage transmission, create fair pricing policies, and encourage competition by providing equal access to the nation's electric power grids. The order requires all owners of electricity transmission facilities to file a proposal to join a Regional Transmission Organization (RTO) or provide reasons that prevent such a filing. In response to this order, the Bonneville Power Administration (BPA) and certain western utilities, including PGE, filed an initial proposal with the FERC to form RTO West, a regional non-profit transmission organization that would operate the transmission system and manage pricing in the Pacific Northwest and portions of other western states. In March 2004, RTO West was renamed Grid West.

Grid West currently operates as a nonprofit membership corporation engaged in development work for future operation as an independent transmission provider that will manage the use and expansion of the region's interconnected transmission system. It responds to the need for greater coordination of regional transmission planning, expansion, and investment activities, and would address identified problems and facilitate changes in the structure of regional power markets. Although Grid West would manage many of the operating functions related to regional transmission facilities, ownership of the facilities would not change and existing transmission rights would be retained. Current members of Grid West include the region's major transmitting utilities, generators, power marketers, transmission dependent utilities, end-use consumers, states, tribes, and public interest groups. BPA has withdrawn from the Grid West development process. As a major transmitting utility, PGE continues to participate in Grid West and monitor its development process, although there remains uncertainty regarding the future of the organization. The Company is also participating in a parallel effort, led by BPA, to enhance the operations of the regional transmission system.

EPAct 2005 was signed into law on August 8, 2005. The new law repealed PUHCA 1935 and significantly revised the Federal Power Act and Natural Gas Act. The law gives the FERC increased statutory authority to implement its stated goals, including mandatory transmission and reliability standards and enhanced oversight of power and transmission markets (including protection against market manipulation). It enacted tax incentives for the development of renewable and cleaner-fuel electric generating resources and for other electric and gas related purposes and substantially changed the qualifying facility provisions of the Public Utility Regulatory Policies Act of 1978 (PURPA). PGE does not expect EPAct 2005 to have a material impact on the Company's operations or financial results.

Retail Rate Changes

PGE filed a general rate case in March 2006 for consideration by the OPUC, with rate adjustments expected to become effective in 2007. PGE's last general rate case was filed in October 2000, with authorized price changes effective on October 1, 2001. Pursuant to a tariff adopted in the 2001 case, PGE annually updates its forecast of net variable power costs. Based on such updates, the OPUC authorized changes in PGE's retail prices for each of the years 2003 through 2006. For further information, see "General Rate Case" and "Resource Valuation Mechanism" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

Integrated Resource Plan

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

PGE is continuing the process to procure approximately 790 MWa in additional energy resources, as recommended in the Company's Integrated Resource Final Action Plan, which was acknowledged by the OPUC in July 2004. Resource acquisitions through 2005 consist of a ten-year purchase agreement for 93 MWa, beginning in 2006, a thirty-year purchase power agreement for approximately 27 MWa (75 MW capacity) of wind generated power, which began in December 2005, and two five-year agreements, consisting of a 25 MW on-peak tolling agreement that began in January 2005, and a power purchase agreement for 25 MWa, beginning in late 2006. The Company has also entered into capacity agreements totaling 400 MW, extending from early 2005 to 2011.

PGE is in the process of constructing Port Westward, a 350 MWa natural gas-fired plant currently planned for completion in the first quarter of 2007. The new plant is expected to have a total capacity of approximately 400 MW, including 25 MW from duct firing capability. Other planned acquisitions consist of approximately 38 MWa (120-125 MW capacity) of additional wind generation, 60 MWa from upgrades to existing plants and contract extensions, and short-term market acquisitions of 125 MWa. In addition, PGE is proceeding with the acquisition of approximately 30-35 MW of additional dispatchable standby generation. The IRP also includes 55 MWa in savings from energy efficiency measures funded by the Energy Trust of Oregon.

PGE has initiated all power supply acquisitions contained in its Final Action Plan and is continuing negotiations to complete its targeted acquisition of wind energy.

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

At the request of the Company, the OPUC agreed that, due to the continuing execution of the current Integrated Resource Final Action Plan, no IRP for the year 2005 was required, with PGE's next filing to be submitted by year-end 2006.

New Oregon Law - Utility Rate Treatment of Income Taxes

Oregon Senate Bill 408, a new law passed by the 2005 Oregon Legislature that became effective on September 2, 2005, seeks to more closely match amounts collected for income taxes under the ratemaking process with income taxes paid to taxing authorities by investor-owned utilities or their consolidated group. PGE is participating in the Commission's comprehensive rule-making process to implement the new law. In October 2005, PGE filed a report, as required by the new law, on taxes "collected" and "paid" (as defined under the temporary rules and Senate Bill 408) for the years 2002-2004. Under the law, however, the first rate adjustment applies only to taxes paid and amounts collected from customers beginning in 2006. In December 2005, Oregon's Attorney General issued an opinion that provides guidelines for the implementation of the law. There is considerable uncertainty regarding several provisions of the law and the Company continues to evaluate its potential effects. For further information, see "New Oregon Law - Utility Rate Treatment of Income Taxes" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

Governmental Actions

City of Portland Investigation

In September 2005, the Portland City Council approved a resolution directing the City Attorney and City staff to obtain from PGE information regarding the collection and payment of utility income taxes. The City has stated that it believes its City Charter provides it with authority for this request. PGE voluntarily provided extensive financial and operational data to the City. The City has since broadened its inquiry to include PGE's power trading activities in 2000 and 2001 and has requested that PGE provide many additional documents and records. PGE has determined that there are a number of legal and practical issues concerning the City's request for additional information, and has declined to provide any additional data to the City while those issues remain unresolved.

Competition and Marketing

General

Restructuring of the electric industry has slowed at both the national level and in the Pacific Northwest. PGE continues to maintain its commitment to service excellence while providing increased choices for its retail customers.

Retail Competition and Marketing

PGE conducts retail electric operations exclusively in Oregon within a state-approved service area. Competitors within the Company's service territory include the local natural gas company, which competes for the residential and commercial space and water heating market, and fuel oil suppliers, which compete primarily for residential space heating customers. In addition, commercial and industrial customers are allowed direct access to competing electricity service suppliers in accordance with Oregon's electricity restructuring law, related regulations, and PGE's tariff; there is no other retail competition from electricity providers. PGE currently offers all customers regulated cost of service and other pricing options. The Company does not operate as an electricity service supplier.

Wholesale Competition and Marketing

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

Power Supply

To meet its customers' energy needs, PGE relies upon its existing base of generating resources, long-term power contracts, and short-term purchases that together provide flexibility to respond to consumption changes and Oregon's electricity restructuring law. Short-term purchases include both spot and term purchases for periods of one year or less in duration.

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 2006.

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

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

Generating Capability

PGE's existing hydroelectric, coal-fired, and gas-fired plants are important resources for the Company, providing 1,973 MW of generating capability (see Item 2. - "Properties" for a full listing of PGE's generating facilities). The Company's lowest cost generating resources are its five FERC licensed hydroelectric projects that incorporate eight powerhouses on the Clackamas, Sandy, Deschutes, and Willamette rivers in Oregon. For further information, see "Hydro Relicensing" in Item 2. - "Properties".

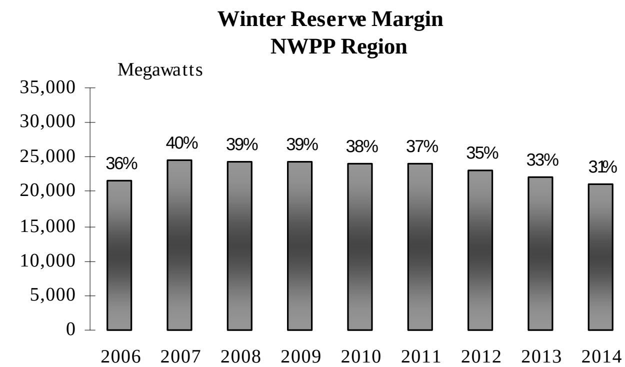
PGE's Integrated Resource Final Action Plan, acknowledged by the OPUC in July 2004, includes the construction of a 400 MW natural gas-fired plant at the Company's Port Westward site. Construction of the plant began in February 2005, with completion expected in the first quarter of 2007.

Purchased Power

PGE supplements its own generation with long-term and short-term wholesale contracts as needed to meet its retail load requirements or provide the most economic mix of resources on a variable cost basis. The Company has long-term power contracts with four hydroelectric projects on the mid-Columbia River, which provide approximately 456 MW of firm capacity. PGE also has firm contracts, ranging from one to thirty years, to purchase 848 MWa of power from other counterparties, including BPA, other Pacific Northwest utilities, and the Confederated Tribes of the Warm Springs Reservation of Oregon, and has a 30-year agreement for 27 MWa of wind capacity with an independent power producer which began in December 2005. In addition, PGE has an exchange contract with a summer-peaking California utility to help meet the Company's winter-peaking requirements, and an exchange contract with another Northwest utility to help meet the Company's summer-peaking requirements. These resources, along with short-term contracts, provide the Company with sufficient firm capacity to serve its peak loads. For further information, see "Power and Fuel Supply" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

Regional System Reliability

PGE relies on wholesale market purchases within the Western Electricity Coordinating Council (WECC) in conjunction with its base of generating resources to supply its resource needs and maintain system reliability. The WECC, a regional electric reliability organization, provides coordination for operating and planning a reliable and adequate electric power system for the western continental United States, Canada, and Mexico. It further supports competitive power markets, helps assure open and non-discriminatory transmission access among members, provides a forum for resolving transmission access disputes, and provides an environment for coordinating the operating and planning activities of its members. The WECC area includes 14 western states, with peak loads that occur at different times of the year. Energy loads in California and the Southwest peak in the summer due to air conditioning use, while northern loads peak during winter heating months. According to WECC forecasts, its members, which serve a population of approximately 71 million, will have sufficient capacity margin to meet forecast demand and energy requirements through the year 2014, assuming the timely completion of planned new generation. The Northwest Power Pool (NWPP) area of the WECC, which contains significant hydro generation, is comprised of all or major portions of the states of Oregon, Washington, Idaho, Montana, Nevada, Utah, and Wyoming, and the Canadian provinces of British Columbia and Alberta. According to NWPP forecasts, hourly peak demand and annual energy requirements in the NWPP through 2014 are projected to grow at annual rates of 1.7% and 1.9%, respectively. The ability of the NWPP to meet peak demand is expected to be adequate for the next ten years, with reserve capability ranging from 31% to 40% of winter peak demand, as indicated in the above table.



PGE's peak load in 2005 was 3,608 MW, of which approximately 50% was met through short-term purchases. On December 31, 2005, PGE's total firm resource capacity, including short-term purchase agreements, was approximately 4,477 MW (net of short-term sales agreements of 1,132 MW).

The Pacific Northwest peak season continues to be in winter months, when home and business heating and lighting cause the highest demand. PGE's all-time peak of 4,073 MW occurred in December 1998.

Restoration of Salmon Runs

Populations of many salmon species in the Pacific Northwest have shown significant decline over the last several decades. A significant number of these species have been granted protection under the federal Endangered Species Act (ESA), which was initially enacted in 1966. The subsequent listing of various species of fish, wildlife, and plants as threatened or endangered species, has resulted in significant changes to federally-authorized activities, such as hydroelectric project operations. Long-term recovery plans for these species may include major operational changes to the region's hydroelectric projects. The biggest change thus far has been a modification in the timing of stored water releases from dams located in the upper parts of the Columbia River and Snake River basins.

PGE continues to evaluate the impact of current and potential ESA listings on the operation of its hydroelectric projects on the Deschutes, Sandy, Clackamas, and Willamette rivers. The Company's consultation with the National Oceanographic and Atmospheric Administration and the United States

Fish and Wildlife Service has identified opportunities for the protection of fish runs on those rivers where PGE operates. ESA consultations on PGE's Clackamas River projects, completed by the agencies in 2003, will be in effect until a new license is granted by the FERC. The Biological Opinion for the Bull Run Project (on the Sandy River), received in 2003, will cover the project's operations and decommissioning.

In 2005, PGE received Biological Opinions and Incidental Take Statements for the Company's Willamette River (Sullivan) and Deschutes River (Pelton Round Butte) projects associated with the issuance of new FERC licenses for these projects. The Biological Opinion and Incidental Take Statement, which provide authorization to licensees for the take of listed species consistent with terms and conditions identified in the consultation, are generally issued at the conclusion of the ESA consultation process associated with obtaining new or amended FERC hydropower licenses. There were no significant changes in the terms and conditions of the Company's new FERC licenses required to minimize take of ESA-protected species.

Fuel Supply

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

Coal

Boardman

PGE has negotiated purchase agreements that provide coal for Boardman's operating requirements through 2008. Available coal supplies are sufficient to meet future requirements of the plant. The coal, obtained from surface mining operations in Wyoming and subject to federal, state, and local regulations, is delivered by rail under two separate 10-year contracts, the terms of which began January 1, 2004. Coal purchases in 2005, totaling 2.3 million tons, contained approximately 0.3% of sulfur by weight. Utilizing electrostatic precipitators, the plant emitted less than the EPA-allowed limit of 1.2 pounds of sulfur dioxide 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 2009. The contract requires that the coal not exceed a maximum sulfur content of 1.5% by weight. In 2005, actual sulfur content for coal used at Colstrip ranged from approximately 0.74% 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 1.5 million tons in 2005. Utilizing wet scrubbers to minimize sulfur dioxide emissions, the plant operated in compliance with EPA's source-performance standards.

Natural Gas

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

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

Currently, PGE transports gas on the Kelso-Beaver Pipeline for its own use under a firm transportation service agreement for all of its pipeline capacity, with capacity offered on an interruptible basis to the extent not utilized by the Company.

Beaver and Port Westward

Firm gas supplies for Beaver and Port Westward (scheduled to become operational in the first quarter of 2007) are purchased up to 24 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 natural gas 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 testing) in 2006.

Coyote Springs

The Coyote Springs generating station utilizes 41,000 Dth/day of firm transportation capacity on three pipeline systems accessing gas fields in Alberta, Canada. Firm gas supplies for Coyote Springs, based on anticipated operation of the plant, are typically purchased up to 24 months in advance. PGE believes that sufficient market supplies of gas are available to fully meet requirements of Coyote Springs in 2006.

Oil

Beaver

The Beaver generating station has the capability to operate at full capacity on No. 2 diesel fuel oil when it is economic or if the plant's natural gas supply is interrupted. To ensure the plant's continued operability under such circumstances, PGE had an approximate 12-day supply of oil at the plant site at December 31, 2005.

Coyote Springs

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

Environmental Matters

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

Regulation

PGE's operations are subject to a wide range of environmental protection laws covering air and water quality, noise, waste disposal, and other environmental issues. The EPA regulates the proper use, transportation, cleanup and disposal of polychlorinated biphenyls (PCBs). State agencies or departments, which have direct jurisdiction over environmental matters, include the Environmental Quality Commission, the DEQ, the Oregon Department of Energy, and the EFSC. Environmental matters regulated by these agencies include the siting and operation of generating facilities and the accumulation, cleanup, and disposal of toxic and hazardous wastes.

Harborton

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

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

Harbor Oil

Harbor Oil, Inc. (Harbor Oil), located in north Portland, was utilized by PGE to process used oil from the Company's power plants and electrical distribution system from at least 1990 until 2003. Harbor Oil is also utilized by other entities for the processing of used oil and other lubricants. A 2003 investigation conducted by the EPA revealed elevated levels of contaminants, including metals, pesticides, and PCBs on the Harbor Oil site. Subsequently, the EPA included Harbor Oil on the federal National Priority List as a federal Superfund site. In 2005, PGE received a Special Notice Letter for Remedial Investigation/Feasibility Study from the EPA, in which the Company was named as one of fourteen PRPs with respect to the Harbor Oil site. Sufficient information is currently not available to determine either the total cost of investigation and remediation of the Harbor Oil site or the liability of PRPs, including PGE.

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

Air Quality
PGE's operations, principally its fossil-fuel electric generation plants, are subject to the federal Clean Air Act (CAA) and other federal regulatory requirements. State governments also monitor and administer certain portions of the CAA and must set standards that are at least equal to federal standards; Oregon's air quality standards exceed federal standards. Primary pollutants addressed by the CAA that affect PGE are sulfur dioxide (SO_2), nitrogen oxides (NO_x), carbon monoxide (CO), and particulate matter. 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 a 60% to 67% capacity. PGE has acquired additional emissions allowances to operate the Boardman plant at forecasted capacity through mid-2008.

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

Federal operating air permits, issued by DEQ, have been obtained for all of PGE's thermal generating facilities.

Regional Haze Study - In accordance with new federal regional haze rules, the DEQ is currently planning an assessment of emission sources pursuant to a Regional Haze Best Available Retrofit Technology (RH BART) process. Several other states are conducting a similar process. The DEQ has sent letters requesting information on twenty-two RH BART eligible sources in Oregon, including PGE's Boardman and Beaver generating plants. A demonstration analysis for identified sources, utilizing modeling techniques, is currently planned to begin during the first half of 2006. Those sources determined to cause, or contribute to, visibility impairment at protected areas in Oregon will be subject to an RH BART Determination. In January 2006, the Company volunteered to participate in a DEQ pilot project that will analyze information about air emissions from Boardman to determine their effect on visibility in the region, particularly in wilderness and scenic areas.

Mercury - In May 2005, the U.S. Environmental Protection Agency established the Clean Air Mercury Rule (CAMR), which regulates mercury emissions from the nation's coal-fired electric generating plants. The CAMR includes a federal "cap-and-trade" program (scheduled to begin in 2010), that establishes a cumulative total ("cap") of mercury emissions from all electric generating plants in the United States and assigns to each state a mercury emissions "budget." Individual states have the choice of adopting this model or establishing their own programs, which must be submitted for approval by November 2006. Oregon is considering whether to incorporate CAMR requirements into the state's program, which could impact the operations of Boardman.

It is not yet known what impacts state and federal regulations on air quality standards may have on future operations, operating costs, or generating capacity of PGE's thermal generating plants. For further information, see "Environmental Matters" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

Item 1A. Risk Factors

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

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

The rates that the OPUC allows PGE to charge for its retail services is the major factor in determining the Company's operating income, financial position, liquidity, and credit ratings. The OPUC has the authority to disallow recovery of any costs that it considers excessive or imprudently incurred. The regulatory process does not provide assurance that PGE will be able to achieve earnings levels authorized.

The Company's March 2006 general rate case filing with the Commission includes separate components related to general (non-power) costs, the recovery of PGE's investment in the Port Westward generating plant (to be completed in the first quarter of 2007), and an adjustment to recover a projected increase in natural gas and purchased power prices in 2007. The filing also proposes a mechanism that addresses power cost volatility and provides for partial recovery of net variable power costs that exceed forecast. In a separate filing, the Company has also applied for a cost deferral and later rate recovery of a portion of incremental power costs caused by the forced repair outage of the Boardman plant. Should the OPUC grant substantially lower rate recovery than requested in these or other future proceedings, it could have a negative effect on results of operations and cash flows, which could impact the Company's credit ratings, potentially weaken its financial profile, and negatively impact liquidity.

Hydro generation comprises approximately 25% of PGE's total energy requirement. While the current RVM mechanism allows PGE to pass certain power cost variability to customers, the Company remains exposed to hydro risk, as there is currently no mechanism to share the risks and rewards of hydro variability with customers. Although the Company in 2004 filed with the OPUC for a hydro generation adjustment to recover high variable power costs caused by recent years' poor regional hydro conditions, this request was denied, and there is no assurance that the mechanism proposed in the Company's pending general rate case will receive sufficient regulatory support to adequately address this risk.

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

The recent forced outage of the Boardman coal plant, a low-cost resource representing about one-fifth of PGE's generating capability, has had a significant negative impact on the Company's earnings due to high replacement power costs. The outage, which began in October 2005 and will continue into the second quarter of 2006, is projected to result in replacement power costs almost $90 million greater than those estimated in setting rates for 2005 and 2006. As noted above, inability to recover such costs in future rates could have a significant negative impact on the Company's earnings.

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

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

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

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

PGE derives a significant 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 significantly affect stream flows and the resulting amount of generation available from these facilities. Significant shortfalls in low-cost hydro production require increased generation from the Company's higher cost thermal plants and/or power purchases in the wholesale market to serve customers.

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

Wholesale electricity prices in the western United States are influenced primarily by factors related to supply and demand. These factors include the adequacy of generating capacity, scheduled and unscheduled outages of generating facilities, hydroelectric generation levels, prices and availability of fuel sources for generation, disruptions or constraints to transmission facilities, weather conditions, economic growth, and changes in technology. Volatility in wholesale energy markets can affect the availability and prices of purchased power and demand for energy sales. Changes in the creditworthiness of large wholesale customers can also affect PGE's variable power costs. Further, disruption in wholesale markets may result in a deterioration of market liquidity, increase the risk of counterparty default, affect the regulatory and legislative process in unpredictable ways, affect wholesale energy prices, and impair PGE's ability to manage its energy portfolio. Changes in wholesale energy prices also affect the market value of derivative instruments and unrealized gains and losses, as well as cash requirements to purchase electricity.

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

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

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

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

These include public ownership initiatives whereby certain customer groups or governments attempt to acquire PGE facilities and equipment in the Company's allocated service territory through use of initiative petition and condemnation processes.

The City of Portland is currently investigating PGE's utility income taxes and prior years' energy trading practices. The Company has responded to the City's information requests regarding the income tax matters. However, PGE has declined to provide any additional data to the City. The City has indicated that it may pursue ratemaking for PGE's retail customers who reside within the city's boundaries. In addition, the City has filed court appeals of the OPUC's approval of the distribution of new PGE common stock, pursuant to Enron's Chapter 11 Plan, and the URP has filed an application with the OPUC for reconsideration of its approval. The ultimate outcome of these matters remains uncertain.

In 2003 and 2004, several public ownership initiatives were advanced whereby customer groups in four counties in which most of PGE's customers reside attempted to acquire Company facilities and form Public Utility Districts. Although such initiatives were rejected by the voters, there is no certainty that similar efforts will not again be attempted.

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

A new law, referred to as Oregon Senate Bill 408, seeks to more closely match amounts collected for income taxes under the ratemaking process with income taxes paid to governmental entities by investor-owned utilities or their consolidated group. There is considerable uncertainty regarding several provisions of the law, with several issues subject to interpretation by the OPUC. Until the Commission issues permanent rules that implement the law, its impact on PGE and its customers will be difficult to assess. For the first quarter of 2006, PGE will continue to be a member of Enron's consolidated group for filing consolidated federal and state income tax returns. Based on the temporary rules, PGE anticipates that there will be material differences between taxes "authorized to be collected" and "taxes paid" in 2006, although the amount of those differences cannot be fully assessed until final rules are adopted. Accordingly, this could have a material adverse affect on the Company's earnings in 2006.

Regulations involving compliance with both new and existing environmental laws related to fish and wildlife could adversely affect PGE's results of operations.

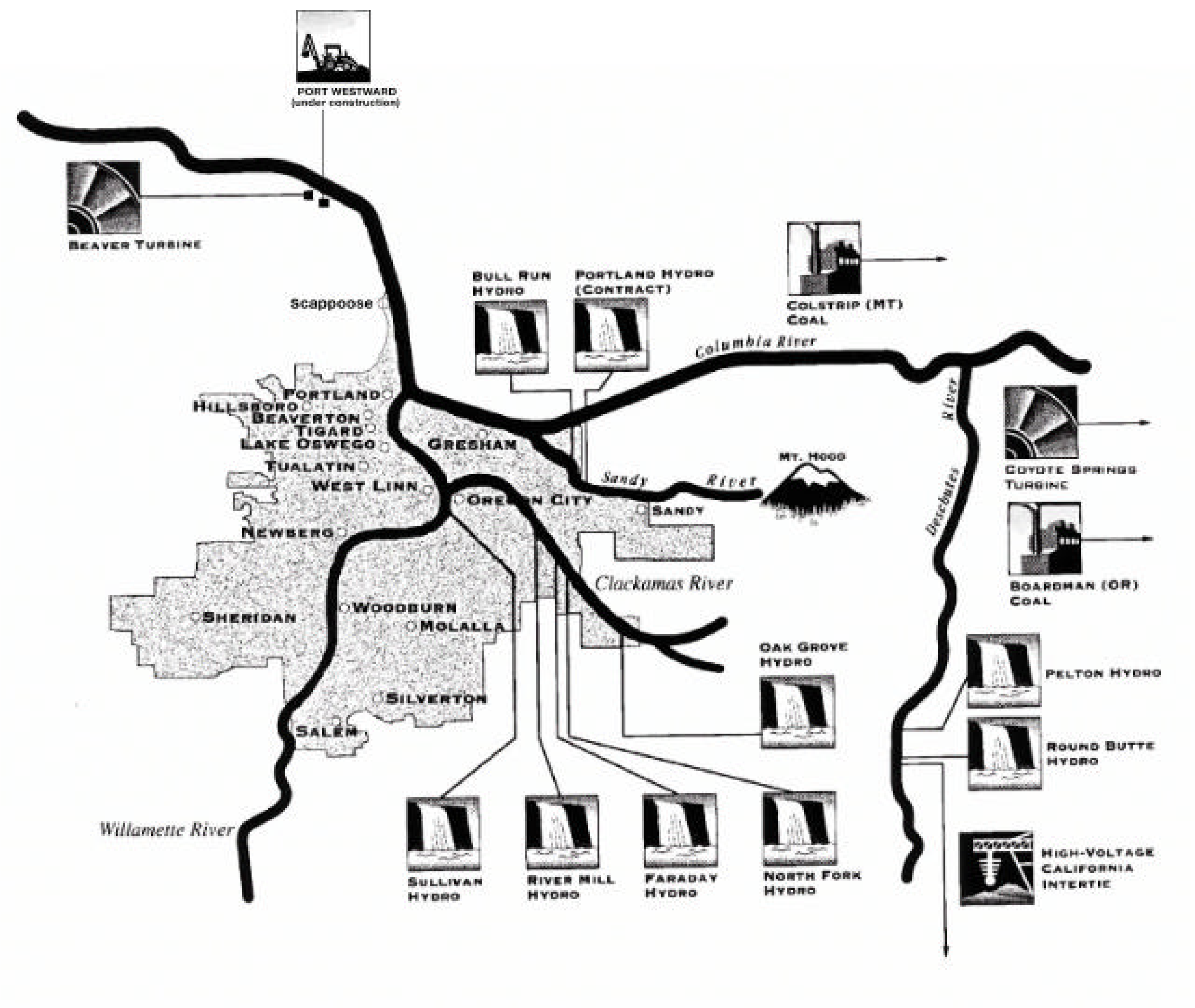
A significant portion of PGE's total energy requirement is comprised of generation from hydroelectric projects on the Columbia, Clackamas, Deschutes, Willamette, and Sandy rivers. Operations of these projects are subject to extensive regulation related to the protection of fish and wildlife. The listing 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. Long-term salmon recovery plans may include further major operational changes to PGE and other hydro projects, and 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.

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

Increases in both the number of customers and the demand for energy will require continued expansion and reinforcement of PGE's generation, transmission, and distribution systems. Construction of new generating facilities (including the Company's Port Westward project) may be affected by various factors, including unanticipated delays and cost increases, which could result in the disallowance of certain costs in the rate determination process. In addition, if construction projects are not completed according to specifications, reduced plant efficiency and higher operating costs could result. Equipment failure, the ability of generating plants to operate as intended, and other factors can result in plant performance that falls below expected levels. Cost and availability of fuel supplies, primarily natural gas and coal, can also significantly impact the cost and output of the Company's generating plants.

Item 2. Properties

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



The following are generating facilities owned by PGE:

Facility	Location	Fuel	Net MW Capability At Dec. 31, 2005 (*)
Wholly Owned:			
Faraday	Clackamas River	Hydro	46
North Fork	Clackamas River	Hydro	58
Oak Grove	Clackamas River	Hydro	44
River Mill	Clackamas River	Hydro	25
Bull Run	Sandy River	Hydro	22
Sullivan	Willamette River	Hydro	16
Beaver	Clatskanie, OR	Gas/Oil	545
Coyote Springs	Boardman, OR	Gas/Oil	243(d)
Jointly Owned:			
Boardman (a)	Boardman, OR	Coal	380
Colstrip 3 and 4 (b)	Colstrip, MT	Coal	296
Pelton (c)	Deschutes River	Hydro	73
Round Butte (c)	Deschutes River	Hydro	225
Total			1,973

(*) PGE ownership share.

(a) PGE operates Boardman and has a 65% ownership interest.
(b) PPL Montana, LLC operates Colstrip 3 and 4; PGE has a 20% ownership interest.
(c) PGE operates Pelton and Round Butte and has a 66.67% ownership interest.
(d) Decreased 2 MW in 2005 due to an assessment of turbine performance.

Hydro Relicensing

PGE holds licenses under the Federal Power Act and from the State of Oregon for its hydroelectric generating plants.

A new 50-year joint license for the Pelton Round Butte hydroelectric project, co-owned by PGE and the Confederated Tribes of the Warm Springs Reservation of Oregon, was issued by the FERC on June 21, 2005. The FERC also approved a settlement agreement, previously completed and signed by all participating parties, that includes provisions for fish passage over the project's three dams.

A new 30-year license for PGE's 16 MW Willamette River project was issued by the FERC on December 8, 2005. As part of the relicensing process, a settlement agreement was reached between the Company and participants in the process, including federal agencies responsible for salmon protection and ESA issues. The agreement includes several improvements to assist downstream passage of juvenile fish, reduce maintenance costs, and enhance production capacity through the replacement of most of the plant's turbines.

The license for the Clackamas River projects expires in 2006. PGE filed an application with the FERC in 2004 to relicense the projects and reached a settlement agreement with participating parties on March 2, 2006 that will be submitted to the FERC for review and approval. For further information, see "Hydro Relicensing" in Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations."

In October 2002, PGE entered into an agreement with state and federal agencies, conservation groups, and others regarding removal of the Company's 22 MW Bull Run hydroelectric project located in the Sandy River basin, including removal of the Marmot Dam in 2007 and the Little Sandy Dam in 2008. The agreement also provides for the protection of threatened fish species and the transfer of 1,500 acres of PGE-owned land to a nonprofit organization toward the creation of a 5,000-acre wildlife and public recreation area. 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, over a ten-year period beginning October 2001, about $16 million in estimated decommissioning costs.

Port Westward

The Port Westward Generating Plant, a 400 MW natural gas-fired facility located in Clatskanie, Oregon, is currently under construction. Construction of the plant began in February 2005 and is proceeding on schedule, with completion expected in the first quarter of 2007.

Transmission

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

Leased Properties

PGE leases its Portland headquarters complex. Coal handling facilities at the Boardman Plant, previously leased by the Company, were purchased in May 2005.

Item 3. Legal Proceedings

<u>Citizens' Utility Board of Oregon v. Public Utility Commission of Oregon and Utility Reform Project and Colleen O'Neill v. Public Utility Commission of Oregon</u>, Marion County Oregon Circuit Court, the Court of Appeals of the State of Oregon, the Oregon Supreme Court.

Following the closing of Trojan, PGE, in its 1993 general rate filing, sought OPUC approval to recover through rates future decommissioning costs and full recovery of, and a rate of return on, its Trojan investment. PGE's request was challenged and PGE requested from the OPUC a Declaratory Ruling (Docket DR 10) regarding recovery of the Trojan investment and decommissioning costs. In August 1993, the OPUC issued a Declaratory Ruling in PGE's favor, citing an opinion issued by the Oregon Department of Justice (Attorney General) 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 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 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. The opinion does not specify the amount or timeframe of any reductions or refunds. On February 9, 2004, PGE appealed this opinion 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 to determine what proceedings are necessary to comply with the Court of Appeals and Marion County Circuit Court orders remanding this matter to the OPUC.

On August 31, 2004, the administrative law judge issued an Order (Scoping Order) defining the scope of the proceedings necessary to comply with the Marion County Circuit Court orders remanding this matter to the OPUC. On October 18, 2004, the OPUC affirmed the Scoping Order. On December 20, 2004, the URP and Class Action Plaintiffs filed an application with the OPUC for reconsideration of the Scoping Order. On February 11, 2005, the OPUC denied reconsideration. On April 18, 2005, URP and Linda K. Williams filed a complaint against the OPUC in Marion County Circuit Court challenging the OPUC's affirmation of the Scoping Order. The OPUC filed a motion to dismiss the complaint, and on September 21, 2005, the Marion County Circuit Court granted the OPUC's motion. Hearings in the first phase of the OPUC proceeding have been held and a decision is pending.

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

On January 17, 2003, two class action suits were filed in Marion County Circuit Court against PGE on behalf of two classes of electric service customers. The Dreyer case seeks to represent current PGE customers that were customers during the period from April 1, 1995 to October 1, 2001 (Current Class) and the Morgan case seeks to represent PGE customers that were customers during the period from April 1, 1995 to October 1, 2001, but who are no longer customers (Former Class, together with the Current Class, the Class Action Plaintiffs). The suits seek damages of $190 million for the Current Class and $70 million for the Former Class, from the inclusion of a return on investment of Trojan in the rates PGE charges its customers.

On April 28, 2004, the plaintiffs filed a Motion for Partial Summary Judgment and on July 30, 2004, PGE also moved for Summary Judgment in its favor on all of Class Action Plaintiffs' claims. On December 14, 2004, the Judge granted the Plaintiffs' motion for Class Certification and Partial Summary Judgment and denied PGE's motion for Summary Judgment. PGE filed a proposed order certifying the issue for an interlocutory appeal. An order rejecting the proposed order was entered 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 May 3, 2005, the Oregon Supreme Court granted both Petitions. Briefing and arguments have been completed and a decision is pending.

<u>David Kafoury, an individual, and Kafoury Brothers, LLC, an Oregon Limited Liability Corporation, each as representative of class, etc. v. Portland General Electric Company,</u> Multnomah County Circuit Court for the State of Oregon, Case No. 0501-00627

On January 18, 2005, David Kafoury and Kafoury Brothers, LLC filed a class action lawsuit in Multnomah County Circuit Court against PGE on behalf of all PGE customers who were billed on their electric bills and paid amounts for Multnomah County Business Income Taxes (MBIT) after 1996. The plaintiffs allege that during the period 1997 through the third quarter 2004, PGE collected in excess of $6 million from its customers for MBIT that was never paid to Multnomah County. The charges were billed and collected under OPUC rules that allow utilities to collect taxes imposed by the county. As a member of Enron's consolidated income tax return, PGE paid the tax it collected to Enron. The plaintiffs seek a judgment against PGE for restitution of MBIT collected from customers. Plaintiffs also seek interest, recoverable costs, and reasonable attorney fees. The Plaintiffs filed an amended complaint on February 25, 2005, adding claims for fraud, unjust enrichment, conversion, statutory violations, and seeking punitive damages. On February 24, 2005, PGE requested a declaratory ruling from the OPUC on this matter. On May 17, 2005, the OPUC agreed to consider the question posed by PGE; whether the OPUC rules authorized PGE collections of the MBIT and, if not, whether refunds are controlled by the OPUC three-year limitation for billing adjustments.

On March 24, 2005, PGE filed in the Circuit Court a motion to abate or in the alternative to dismiss. On May 23, 2005, the Circuit Court granted PGE's motion for a stay for all purposes until October 15, 2005, with the opportunity to renew if the OPUC has not issued its declaratory ruling.

On October 5, 2005, the OPUC issued an order in the declaratory ruling docket in which it determined that the rules in question required only that PGE allocate this tax to Multnomah County customers and did not require that PGE calculate it in any particular way. PGE notified the Court of the Company's intent to voluntarily refund MCBIT (plus interest) to customers and filed motions requesting the Court's guidance regarding the number of years for which refunds should be made.

On December 28, 2005, the parties agreed to a settlement by which PGE will make refunds and payments totaling $10 million, inclusive of interest and plaintiffs' attorney fees, costs, and expenses as approved by the Court's final order. Distribution to customers is limited to amounts collected during the period 1999 through 2005. The settlement is subject to final approval by the Multnomah County Circuit Court following a hearing currently scheduled for late July 2006.

<u>Port of Seattle vs. Avista Corporation, Avista Energy, Inc., El Paso Electric Company, Idacorp, Inc., Idaho Power Co., PacifiCorp, Portland General Electric Company, Powerex Corporation, PPL Montana, LLC, Puget Energy, Inc., Puget Sound Energy, Inc., Scottish Power, PLC, Sempra Energy, Sempra Energy Resources, Sempra Energy Trading Corp., Transalta Corporation, Transalta Energy Marketing, Inc.</u> United States District Court for the Western District of Washington, Case No. CV03-1170P.

On May 21, 2003, the Port of Seattle, Washington (Port) filed a complaint in the U.S. District Court for the Western District of Washington against PGE and sixteen other companies (Defendants) alleging violation of both the Sherman Act and the Racketeer Influenced and Corrupt Organization Act, fraud, and, with respect to Puget Energy, Inc. and Puget Sound Energy, Inc., breach of contract. The complaint alleges that the price of electric energy purchased by the Port between November 1997 and June 2001 under a contract with Puget Sound Energy, Inc. was unlawfully fixed and artificially increased through various actions alleged to have been undertaken in the Pacific Northwest power markets among Defendants and Enron Corp., Enron Energy Services, Inc., Enron North America Corp., Enron Power Marketing, Inc., and others. The complaint alleges actual damages of $30.5 million suffered by the Port and seeks recovery of that amount, plus punitive damages and reasonable attorney fees. On December 4, 2003, this case was transferred to the Southern District of California.

On May 12, 2004, 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. The plaintiffs in this case have appealed the Court's decision to the United States Ninth Circuit Court of Appeals. A decision is pending.

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

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

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

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

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

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

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

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

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

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

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

On July 18, 2005, an Amended Complaint was filed, which modifies the named plaintiffs and provides further clarification of the underlying claims. Trial is scheduled to start in early 2007.

Portland General Electric Company v. International Brotherhood of Electrical Workers, Local No. 125 (Union Grievances), Multnomah County Circuit Court for the State of Oregon, Case No. 0205-05132.

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

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

Both the U.S. District Court and the Bankruptcy Court approved the settlement of the class action litigation styled In re Enron Corp. Securities Derivative & "ERISA" Litigation, Pamela M. Tittle, et al, v. Enron Corp., et al, Civil Action No. H-01-3913, U.S. District Court for the Southern District of Texas, Houston Division (Tittle Action) and on September 13, 2005, the U.S. District Court entered a Bar Order in the Tittle Action, which specifically bars all claims arising out of that case, including the IBEW grievance proceeding. On October 18, 2005, at the request of the Oregon Court of Appeals, PGE filed a response memorandum in which PGE argued that the Bar Order makes the grievance moot. A decision is pending.

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

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

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

On February 10, 2006, the City of Portland ("City") appealed the December 14, 2005 order of the OPUC that authorized the issuance of new PGE common stock (OPUC Order). Appeals were filed both in the Marion County Circuit Court and the Oregon Court of Appeals. The City filed its appeals in both courts due to the jurisdictional uncertainty created by new Oregon law governing appeals of OPUC decisions. In its appeal to the Circuit Court, the City alleges the OPUC made its decision on an inadequate record, failed to enter adequate findings in support of its decision, abused the discretion granted it by Oregon law and based its decision on a statute that constituted an unlawful delegation from the Oregon Legislature. For relief, the City requests the OPUC Order be modified, reversed or remanded. In the Court of Appeals filing, the City alleges it is an aggrieved party and asks for judicial review without further details. On February 23, 2006, the OPUC filed a Motion to Hold Case in Abeyance with the Marion County Circuit Court in order to seek summary determination from the Court of Appeals regarding the proper court to hear the City's appeal. The City and other defendants to the action, including PGE, did not oppose the motion. The Circuit Court has not ruled on this motion.

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

None.

Part II

Item 5. Market for Registrant's Common Equity and Related Stockholder Matters

PGE is a wholly owned subsidiary of Enron, which owns all 42,758,877 shares of PGE's outstanding common stock. Cash dividends declared on common stock were as follows (in millions):

Quarter	2005	2004
1	$ -	$ -
2	-	-
3	150	-
4	-	-

PGE is restricted, without prior OPUC approval, from making dividend distributions to Enron that would reduce PGE's common equity capital below 48% of total capitalization (excluding short-term borrowings).

On December 14, 2005, the OPUC issued an order approving the issuance of new PGE common stock and the corresponding cancellation of the existing stock owned by Enron, in accordance with Enron's Chapter 11 Plan. The order includes a stipulation containing several conditions, including a requirement that, after issuance of the new stock, PGE cannot pay a dividend that would cause the common equity capital percentage to fall below 48% (plus $40 million) without Commission approval. PGE has agreed to maintain the additional $40 million of common equity pending the outcome of its next general rate case to assure the Company's financial capacity to absorb any adjustment(s) in its revenue requirement related to its ownership by Enron. The requirement is reduced to 45% when the Disputed Claims Reserve (DCR) holds between 20% and 40% of the issued and outstanding common stock of PGE, with no minimum common equity capital percentage requirement when the DCR holds less than 20% of the issued and outstanding common stock of PGE. Other conditions include a requirement that the OPUC be notified (simultaneously with the public) of any dividend declared by PGE's Board of Directors and that, before the issuance of new common stock, PGE cannot make a dividend distribution to Enron unless PGE has a rating on its senior secured debt of not lower than BBB+ from Standard & Poor's.

For further information, see Note 4, Common and Preferred Stock, in the Notes to Financial Statements.

Item 6. Selected Financial Data

	For the Years Ended December 31				
	2005	**2004**	**2003**	**2002**	**2001**
			(In Millions)		
Operating Revenues (a)	$1,446	$1,454	$1,752	$1,855	$2,420
Net Operating Income	126	150	124	135	134
Net Income (b)	64	92	60	66	34
Total Assets (c)	3,638	3,403	3,372	3,455	3,622
Long-Term Debt (d)	890	922	983	1,046	972

(a) Operating Revenues for 2003 through 2005 reflect the October 1, 2003 adoption of EITF 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, and 'Not Held for Trading Purposes'." EITF 03-11 requires that realized gains and losses associated with non-trading derivative activities that are not physically settled be reported on a net basis. Prior to October 1, 2003, such settlements were recorded on a gross basis in both Operating Revenues and Purchased Power and Fuel expense. Amounts for periods prior to October 1, 2003 were not reclassified. Accordingly, Operating Revenues for these periods are not fully comparable to the years 2003 through 2005 and do not reflect PGE's current reporting. For further information, see Note 1, Summary of Significant Accounting Policies, in the Notes to Financial Statements.

(b) Net Income for 2003 was restated. For further information, see Note 16, Restatement of Prior Period Financial Statements, in the Notes to Financial Statements.

(c) Amounts for 2001 and 2002 were reclassified from those reported in the respective Form 10-Ks to reflect the transfer of accumulated asset retirement removal costs from Accumulated Depreciation to Other liabilities, in accordance with SFAS No. 143, Asset Retirement Obligations, and SFAS No. 71, Accounting for the Effects of Certain Types of Regulation.

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

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

Overview

PGE is a single integrated electric utility engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the State of Oregon, as well as the wholesale sale of electricity and natural gas throughout the western states. PGE's mission is to be a company that customers depend on to provide electric service in a safe and reliable manner with excellent customer service at a reasonable price. The OPUC establishes tariffs and retail revenue requirements based upon the cost to serve retail customers and a fair return on investment, using a forecasted test year and an original cost rate base. Wholesale power and transmission prices are regulated by the FERC.

While Oregon's electricity restructuring law provides for both direct access to competing energy suppliers and for market price options, the Company remains obligated to provide service to all of its retail customers, the large majority of which buy electricity at prices determined by the cost of service. Subject to regulatory review and timing, PGE expects the OPUC to recognize all prudently-incurred costs in setting prices, although there can be no assurance that the Company will have an opportunity to fully recover its costs through prices set in the regulatory process. While customer prices applicable to projected power costs are currently adjusted on an annual basis, prices applicable to non-power costs are adjusted only in a general rate proceeding. As electricity prices are fixed during the year, fluctuations in energy sales, hydro output, plant availability, and power and fuel prices can significantly impact the Company's earnings.

Future Ownership of PGE - Enron and PGE are moving forward to distribute new PGE common stock to the Debtors' creditors holding allowed claims in accordance with the Chapter 11 Plan, with applications approved by all required regulatory agencies. The issuance of new PGE common stock is currently expected to take place on or about April 3, 2006, and PGE has filed an application to list the stock on the New York Stock Exchange. Following the issuance, PGE will no longer be a subsidiary of Enron. Enron has also indicated that it will continue to consider credible offers to purchase PGE's common stock until the new common stock is issued. The transition from Enron's ownership of PGE has continued, with control of employee benefit and retirement savings plans returned to the Company at the beginning of 2005. The Company's Board of Directors has been expanded, with six new members appointed in January 2006. For further information, see "Future Ownership of PGE" in "Financial and Operating Outlook" of this Item 7.

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

Like most utilities, PGE's business is affected by the general economy and by population growth in its service territory. The Company continues to experience customer growth, adding approximately 55,000 retail customers in the last five years (including 13,000 in 2005), and now serves over 780,000 retail customers as the largest supplier of electricity in the state. Although slowing somewhat in the last half of 2005, the state's economy has generally continued to rebound from the 2001-2003 period, adding over 100,000 jobs (including over 16,000 in manufacturing) during the last two years, resulting in annual average payroll gains of 2% in 2004 and 3.4% in 2005. Non-farm employment (seasonally adjusted) in December 2005 exceeded the previous peak, with the unemployment rate falling from a high of 8.5% in July 2003 to 7.0% at year-end 2004 to 5.7% at the end of 2005. Continued high energy prices and rising short-term interest rates, however, could affect future growth of both the national and state economy.

PGE seeks to exert a positive influence on the long-term economic strength of the Company's service area and continues to play an active role in supporting growth and business development in the region. The Company works with local, state and regional agencies to assist existing businesses with operating and expansion plans and to provide assistance to businesses considering new activity in Oregon. PGE has played a key leadership role in assisting communities in the Company's service area with economic development strategies, including those initiated at the recent Oregon Business Plan Summit, and has been instrumental in the growth of key industry clusters representing a large number of metals and transportation equipment businesses in the state.

Power Supply - PGE manages its power supply to secure reasonably priced power for customers by effectively using the Company's generating assets and marketing and operational expertise. PGE can meet approximately 75% of its peak load requirement with output from its generating plants and long-term hydro contracts, with the remaining 25% met with short-term and other long-term power purchases in the wholesale market. The portion of retail load met with power purchases can increase if it becomes more economic to purchase electricity than to generate it with the Company's thermal resources.

PGE's twelve diversified generating plants (40% gas/oil, 34% coal, and 26% hydro) have both base-load and peaking capabilities, with fuel for thermal plants supplied under short-term agreements and spot-market purchases, allowing the Company to dispatch its thermal resources based upon the market price of wholesale power relative to the market price of natural gas or coal. Wholesale energy market prices have continued to increase over the last year, reflecting higher natural gas prices and below-normal regional hydro conditions. PGE remains active in wholesale energy markets in order to meet retail load requirements. The Company utilizes wholesale electricity and fuel purchases, as well as its generating plants, to maintain a balanced position.

Regional water conditions in 2005 were below both average and 2004 levels, resulting in reduced generation from PGE's hydro projects. Output from mid-Columbia River hydro projects, with which PGE has long-term power purchase contracts, was slightly higher in 2005. Regional hydro conditions, including those on both the Clackamas and Deschutes river systems where the Company's facilities are located, are currently projected to be near normal for 2006.

Renewable generation purchased from a 27 MWa wind farm became available on December 1, 2005, with the 50-turbine project generating enough electricity to power 18,000 homes. This is PGE's largest renewable power purchase to date and marks the first major step toward meeting the Company's renewable power supply goal of 200 MW. The Company continues to implement its Integrated Resource Plan to meet the future electricity needs of customers, with construction of the 400 MW natural gas-fired Port Westward plant proceeding on schedule, with completion expected in the first quarter of 2007.

In June 2005, the FERC approved a 50-year joint license application for the Pelton Round Butte hydro project and in December 2005 a new 30-year license was issued for PGE's 16 MW Willamette River project. A settlement agreement related to the previously filed license application for the Company's four Clackamas River projects has been signed by participating parties and will be submitted to the FERC for review and approval. These facilities continue to provide a low-cost source of power for PGE customers.

Operations - In October 2005, following the detection of vibrations in Boardman's steam turbine rotor, the plant was taken out of service, with the rotor removed in mid-November and shipped to an east coast facility for repair. During the process of returning the plant to operation in early February 2006, the generator rotor was damaged and subsequently removed for further examination and repairs. It is currently estimated that the plant will be operational by late April 2006. Replacement power costs of approximately $41 million were incurred during the fourth quarter of 2005, with first quarter 2006 costs estimated at $45 million. Estimated replacement power costs for April 2006 are expected to range from $200,000 to $300,000 per day. During the plant's extended outage, annual maintenance requirements, originally scheduled for the second quarter of 2006, were completed.

Aside from the extended repair outage at Boardman, PGE's generating plants continued to operate well in 2005, with total output approximating that of 2004. Required annual maintenance at the Company's thermal facilities was successfully completed by the end of the year's third quarter.

PGE utilized its mix of generating assets and activities in the wholesale marketplace to meet the 2005 electricity needs of its customers and offset the adverse effects of the year's moderate drought conditions and the extended repair outage at Boardman. Increased retail energy deliveries (including those to commercial and industrial customers that purchase their energy from ESSs) reflect continued customer growth and an improved economy, with gains in all major customer sectors. Weather adjusted retail energy deliveries to PGE and ESS customers are expected to increase by approximately 2% in 2006.

PGE continues to invest in its transmission and distribution systems and in additions and upgrades to its generating facilities. Decommissioning of the closed Trojan nuclear plant is proceeding, and in May 2005, following the completion of radiological decommissioning and approval by the NRC, the plant's facility operating license was terminated. PGE has accelerated the planned demolition of major non-radiological structures at Trojan, including the cooling tower and those buildings that once housed the plant's turbine, reactor, and spent fuel pool.

2005 Financial Performance - Due largely to Boardman's extended repair outage during most of the fourth quarter of 2005, PGE's earnings declined about 30% from 2004. The unplanned outage required that PGE replace its portion of the plant's generation with higher-priced wholesale power purchases and increased natural gas-fired generation, resulting in a significant decrease in PGE's net operating income and a net loss for the fourth quarter of 2005. Earnings for 2005 were also negatively affected by higher operating expenses and by PGE's decision, as part of a settlement, to make refunds and payments totaling $10 million to Multnomah County customers for business income taxes collected in prior years.

Despite the challenges of poor hydro conditions in 2005, the lack of any power cost adjustment mechanism, and the extended Boardman outage, PGE continues to maintain adequate liquidity and stable operating cash flow. The Company secured a new $400 million five-year credit facility in May 2005 and continues to effectively invest in its systems, acquire and plan for new power supply resources, and maintain operational efficiency.

Regulatory Matters - The "Resource Valuation Mechanism" (RVM) process, by which retail prices are adjusted annually with changes in projected power costs, has enabled PGE to adjust customer prices on a more timely basis to reflect the expected variable cost of power. This process resulted in moderate average rate increases for 2005 and 2006. A previously-filed Hydro Generation Adjustment tariff and deferral application, which would have allowed for the deferral and future rate recovery of a portion of power cost changes caused by variations in hydro conditions, was denied by the OPUC.

PGE has also filed an application with the OPUC seeking deferral, for future ratemaking treatment, of excess replacement power costs related to Boardman's outage for repairs to the plant's steam turbine rotor, which ended on February 5, 2006. PGE has determined, however, that it will not file an application to defer such costs related to the outage resulting from damage to the generator rotor, which began February 6, 2006. For further information, see "Boardman Coal Plant - Extended Outage" in "Financial and Operating Outlook" of this Item 7.

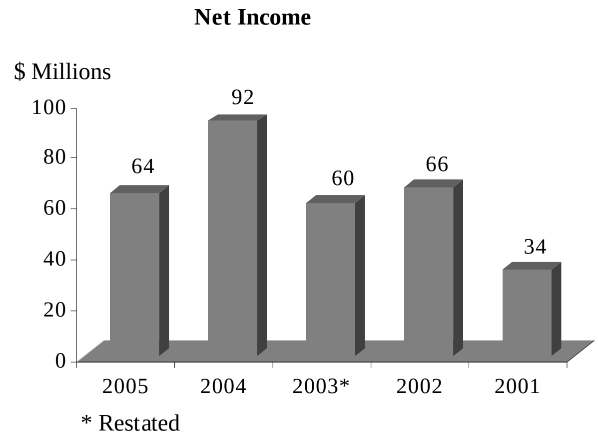
A new law, Oregon Senate Bill 408, seeks to more closely match amounts collected for income taxes under the ratemaking process with income taxes paid to governmental entities by investor-owned utilities or their consolidated group. PGE is participating in the Commission's comprehensive rule-making process to implement the new law. The Company has filed a report, as required by the new law, on taxes "collected" and "paid" (as defined under temporary rules and Senate Bill 408) for the years 2002-2004. Under the law, however, the first rate adjustment applies only to taxes paid and amounts collected from customers beginning in 2006. There is considerable uncertainty regarding several provisions of the law and the Company continues to evaluate its potential effects.

In order to align PGE's rate structure to sufficiently cover its operating costs, the Company filed a general rate case in March 2006 for consideration by the OPUC**.** Major components of the filing include power costs and the recovery of PGE's investment in Port Westward. The Commission's review is estimated to take from nine to ten months, with rate adjustments expected to become effective in early 2007.

Results of Operations

2005 Compared to 2004

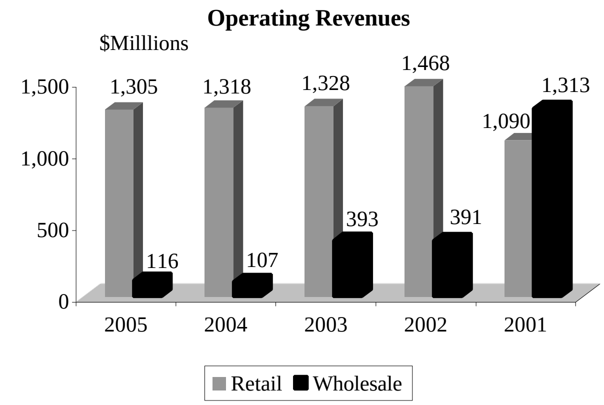
PGE's net income in 2005 was $64 million compared to $92 million in 2004. The decrease was due primarily to reduced margins on energy sales, caused by replacement power costs for the extended, unplanned outage at the Boardman coal plant for repair of the plant's turbine rotor. In addition, results for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

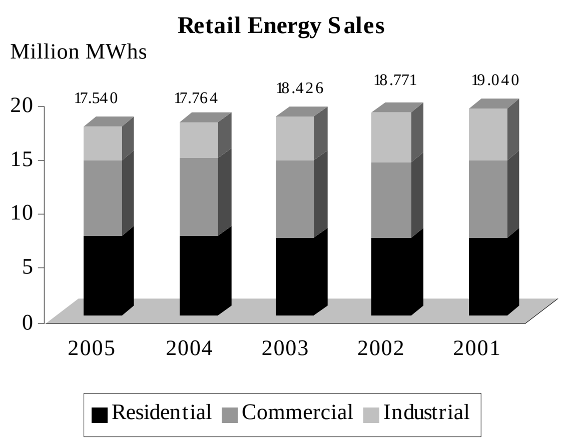


The following table summarizes Operating Revenues and Energy Sold and Delivered for 2005 and 2004:

Operating Revenues (In Millions)	2005	2004	Increase/ (Decrease)
Retail Operating Revenues:			
Retail	$ 1,305	$ 1,311	$ (6)
Direct Access Customer Revenues	-	7	(7)
Total Retail Revenues	1,305	1,318	(13)
Wholesale (Non-Trading)	116	107	9
Other Operating Revenues:			
Trading Activities - net	-	1	(1)
Other	25	28	(3)
Total Operating Revenues	$ 1,446	$ 1,454	$ (8)
Energy Sold and Delivered (In Thousands of MWhs)			
Retail Energy Deliveries			
Retail Energy Sales	17,540	17,764	(224)
Energy Delivered to Direct Access Customers	1,214	776	438
Total Retail Energy Deliveries	18,754	18,540	214
Wholesale (Non-Trading)	2,094	2,539	(445)
Trading Activities	815	9,699	(8,884)
Total Energy Sold and Delivered	21,663	30,778	(9,115)

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





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

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

Purchased Power and Fuel expense for 2005 increased $4 million (1%) from 2004. An 11% increase in PGE's average variable power cost was largely offset by both a reduction in total system load and a $24 million decrease related to the amortization of costs deferred under power cost adjustment mechanisms in effect during 2001 and 2002, which were later recovered from customers (fully offset within Retail revenues). The increase in average variable power cost was caused primarily by approximately $41 million of incremental power costs incurred to replace coal-fired generation at Boardman, which was taken out of service in mid-October 2005 for removal and repair of the plant's turbine rotor. Lower hydro production in 2005 (due to low stream flows) also contributed to the year's higher average variable power cost. Such cost increases were partially offset by higher unrealized gains from derivative instruments. Company generation decreased about 4% from 2004, with 17% and 9% reductions, respectively, in combustion turbine and hydro production partially offset by increased coal-fired generation, primarily from Colstrip. Total generation met approximately 42% of PGE's retail load in 2005, compared to 43% in 2004.

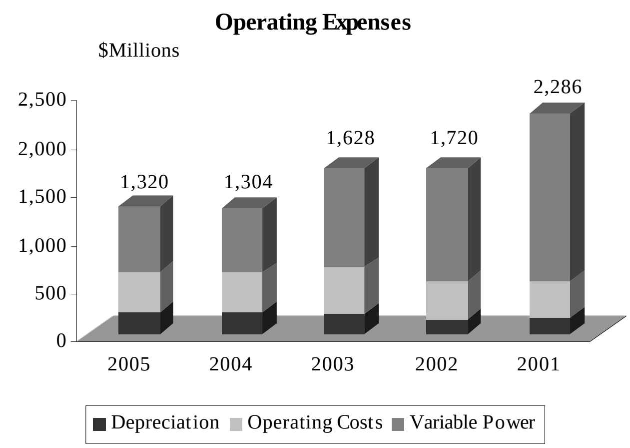
The following table indicates PGE's total system load (including both retail and wholesale) for the last two years. Average variable power costs exclude unrealized gains and losses from derivative instruments and the effect of credits to purchased power and fuel costs related to PGE's power cost adjustment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

Megawatt-Hours/Variable Power Costs

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

(* includes wheeling costs)

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



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

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

2004 Compared to 2003

PGE's net income in 2004 was $92 million compared to $60 million in 2003. Results for 2003 included after tax provisions totaling approximately $19 million related to investigations into wholesale power market activities during 2000 and 2001, consisting of $14 million related to amounts due the Company for wholesale electricity sales made in California and $5 million related to a settlement agreement between PGE, the FERC, and other parties. In addition, results for 2003 have been restated to include an additional $2 million after tax gain in the cumulative effect of a change in accounting principle. For further information, see Note 16, Restatement of Prior Period Financial Statements, in the Notes to Financial Statements.

The remaining increase in net income in 2004 was due primarily to improved margins on energy sales resulting from economic decisions related to the utilization of the Company's thermal generating assets and activities in the wholesale marketplace. In addition, 2003 margin reflects a disallowance by the OPUC of certain power purchase contracts in prices charged customers. These factors, along with lower interest charges and administrative expenses, more than offset the impact of retail energy sales that continued below the levels projected in the Company's most recent general rate case.

The following table summarizes Operating Revenues and Energy Sold and Delivered for 2004 and 2003:

Operating Revenues (In Millions)	2004	2003	Increase/ (Decrease)
Retail Operating Revenues:			
Retail	$ 1,311	$ 1,328	$ (17)
Direct Access Customer Revenues	7	-	7
Total Retail Revenues	1,318	1,328	(10)
Wholesale (Non-Trading)	107	393	(286)
Other Operating Revenues:			
Trading Activities - net	1	2	(1)
Other	28	29	(1)
Total Operating Revenues	$ 1,454	$ 1,752	$ (298)
Energy Sold and Delivered (In Thousands of MWhs)			
Retail Energy Deliveries			
Retail Energy Sales	17,764	18,426	(662)
Energy Delivered to Direct Access Customers	776	-	776
Total Retail Energy Deliveries	18,540	18,426	114
Wholesale (Non-Trading)	2,539	9,966	(7,427)
Trading Activities	9,699	13,551	(3,852)
Total Energy Sold and Delivered	30,778	41,943	(11,165)

The decrease in Retail Revenues from 2003 was caused by lower energy sales. Retail energy sales decreased 4% due largely to a 22% decline in industrial sales, most of which was attributable to two large customers, with one now generating its own power requirements and the other now served by an ESS. The decrease in revenue from these two customers was approximately $29 million, of which about half was attributable to the customer now served by an ESS. An additional $18 million decrease in retail revenues resulted from the loss of other non-residential customers now served by ESSs. The reduction in industrial energy sales was partially offset by higher residential and commercial sales, which increased by about 2.4% and 1%, respectively, in 2004. An approximate 11,700 average increase in customers served, combined with significantly colder January weather, more than offset the effects of mild weather during the remainder of 2004. Also partially offsetting the effect of reduced industrial energy sales was an approximate 0.4% average rate increase for 2004. (For further information, see "Resource Valuation Mechanism" in "Financial and Operating Outlook" of this Item 7).

Lower wholesale revenues and energy sales resulted primarily from the adoption of EITF 03-11 in the fourth quarter of 2003. Beginning October 1, 2003, revenues and expenses related to non-trading energy activities that are not physically settled, formerly included on a "gross" basis within both Operating Revenues and Purchased Power and Fuel expense, are recorded on a "net" basis in Purchased Power and Fuel expense. This change resulted in a decrease in reported non-trading wholesale energy sales and purchases and related amounts in comparative financial statements. Although determination of the effect of the change on prior year reported revenues and expenses was not practicable, the change had no impact on reported net income. The remaining decrease in wholesale revenues was attributable to a 23% reduction in wholesale energy sales. The decrease was partially offset by a 7% increase in average prices, due primarily to higher natural gas prices and a reduction in regional hydro availability.

Other Operating Revenues approximated that of 2003, with increased revenue from the sale of transmission capacity more than offset by decreased gains on the sale of natural gas in excess of generating plant requirements, as power purchases in the wholesale market economically displaced more expensive gas-fired thermal generation.

Purchased Power and Fuel expenses for 2004 decreased $361 million from 2003, primarily due to the adoption of EITF 03-11, which resulted in reductions to expense of $296 million and $90 million in 2004 and 2003, respectively. In addition, expenses for 2003 include a $22.5 million ($14 million after taxes) provision for uncollectible accounts receivable for wholesale electricity sales in the California market. (For further information, see "Receivables and Refunds on Wholesale Market Transactions" in "Financial and Operating Outlook" of this Item 7). The remaining $132 million decrease from 2003 is largely attributable to a reduction in power purchased to meet a lower total system load requirement as well as a lower average variable power cost. Lower term power prices for power delivered in 2004 more than offset higher spot power prices during the year. Combined with a decrease in the average cost of both combustion turbine and coal-fired generation, PGE's average variable power cost decreased 1% from that of 2003 (for further information, see "Power and Fuel Supply" in "Financial and Operating Outlook" of this Item 7). Total Company generation increased 2% in 2004, with higher combustion turbine generation (due to the forced outage of Coyote Springs during part of 2003) partially offset by decreased coal-fired generation, due primarily to the Boardman plant's 2004 extended maintenance outage. PGE hydro production approximated that of 2003. Total generation met approximately 43% of PGE's retail load in 2004, compared to 40% in 2003.

The following table indicates PGE's total system load (including both retail and wholesale) for the last two years (excludes energy trading activities). Average variable power costs exclude the effect of provisions for uncollectible wholesale accounts receivable.

Megawatt-Hours/Variable Power Costs

	Megawatt-Hours (thousands)		Average Variable Power Cost (Mills/KWh)	
	2004	2003	2004	2003
Generation	8,114	7,922	15.0	15.6
Term Purchases	12,017	19,365	30.9	35.0
Spot Purchases	1,343	2,404	41.4	38.5
Total System Load	21,474	29,691	28.2*	32.2*

(* includes wheeling costs)

Production, distribution, administrative and other expenses increased $10 million (4%) from 2003 due primarily to costs related to an extended maintenance outage at the Boardman coal plant, increased service restoration costs (net of insurance recovery) related to a five-day snow and ice storm in January 2004, and higher distribution expenses, including increased tree trimming requirements. A decrease in corporate overhead charges from Enron was largely offset by increases in both employee benefit expenses (including medical and pension costs) and customer service and support expenses. Corporate overhead charges billed by Enron, approximately $14 million in 2003, were terminated for 2004.

Depreciation and Amortization expense increased $20 million (9%) due partially to a $9 million increase in amortization of regulatory assets (including costs related to implementation of Oregon's electricity restructuring law), the effects of which are fully offset within Operating Revenues. The remaining increase resulted from increased depreciation and amortization of utility plant due to normal property additions, and a reduction in the deferral of certain regulatory assets.

Income taxes related to utility operations increased $7 million primarily due to higher taxable income.

Other Income (Miscellaneous) increased $3 million. Results for 2003 included an $8.5 million charge related to a settlement agreement between PGE, the FERC, and other parties related to investigations into prior years' wholesale power market activities. Partially offsetting the effect of this charge was a reduction in interest income in 2004, related primarily to lower remaining balances to be collected under the Company's 2000-2001 power cost adjustment mechanisms. A $3 million reduction in tax benefits from 2003 was due primarily to the increase in income.

Interest Charges decreased $10 million (13%) due to both a lower level of outstanding long-term debt in 2004 and to the replacement of higher rate debt in the second half of 2003.

Capital Resources and Liquidity

Review of Cash Flow Statement

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

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

Cash provided by operating activities totaled $372 million in 2005 compared to $340 million in 2004. The increase was due primarily to an approximate $33 million reduction in payments for power and fuel purchases, a $22 million increase in cash collateral deposits received from certain wholesale customers, a $20 million increase related to the 2004 purchase and 2005 liquidation of short-term investments, and a $4 million decrease in interest payments. These items were partially offset by a $5 million increase in income tax payments to Enron, a $32 million decrease in amounts received for sales of electricity, and a $10 million contribution made to the Company's Pension Trust in 2005.

Existing cash and short term investments, along with cash provided by operations, were used to meet PGE's day-to-day requirements during 2005.

Investing Activities consist primarily of improvements to PGE's distribution, transmission, and generation facilities. The $61 million increase in capital expenditures in 2005 is attributable to construction costs of Port Westward, the purchase of the Boardman coal handling facility (which was previously leased by the Company), and hydro relicensing activities. Other expenditures were related to the expansion of PGE's distribution system to support both new and existing customers within the Company's service territory.

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

During 2005, PGE retired $18 million of First Mortgage Bonds, $11 million of conservation bonds, and $3 million of preferred stock. In July 2005, PGE paid a common stock dividend of $150 million to Enron. No cash dividends on common stock were declared or paid in 2004. PGE paid $1 million of preferred stock dividends in 2005 (classified as interest expense).

The issuance of additional First Mortgage Bonds and preferred stock requires PGE to meet earnings coverage and security provisions set forth in the Company's Articles of Incorporation and the Indenture of Mortgage and Deed of Trust securing the bonds. As of December 31, 2005, PGE has the capability to issue additional preferred stock and First Mortgage Bonds in amounts sufficient to meet its anticipated capital and operating requirements.

At December 31, 2005, PGE had a $400 million five-year revolving credit facility with a group of commercial banks. The facility, which is unsecured, replaced the Company's $50 million 364-day revolving credit facility, which expired in May 2005, and a $100 million three-year facility. It is available for general corporate purposes, with the maximum amount available to PGE for borrowings and/or the issuance of standby letters of credit. At December 31, 2005, PGE had utilized approximately $17 million in letters of credit, with $11 million related to wholesale trading activities and $6 million related to Port Westward.

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 such date may be extended for an additional year for those lenders who agree to an extension. The facility requires annual fees based on PGE's unsecured credit rating, and contains customary covenants and default provisions, including a requirement that limits consolidated indebtedness, as defined in the facility, to 65% of total capitalization. At December 31, 2005, the Company's indebtedness to total capitalization ratio, as calculated under the facility, was 41.7%.

Prior to the repeal of PUHCA 1935 by EPAct 2005, PGE had SEC approval to issue and sell unsecured short-term debt. Following the repeal of PUHCA 1935, PGE's issuance of short-term debt requires approval by the FERC. Pursuant to PGE's application filed in December 2005, the FERC issued an order on February 3, 2006 which authorizes the Company to issue short-term debt, in an amount not to exceed $400 million outstanding at any one time, over the two-year period February 8, 2006 through February 7, 2008.

Cash Requirements

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

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

PGE's financial objectives include the balancing of debt and equity to maintain a low weighted average cost of capital while retaining sufficient flexibility to meet the Company's financial obligations. PGE's objective is to maintain a common equity ratio (common equity to total consolidated capitalization, including current debt maturities) of approximately 50%. Achievement of this objective while sustaining sufficient cash flow is necessary to maintain acceptable credit ratings and allow access to long-term capital at attractive interest rates. PGE's common equity ratios were 57.5% and 58.4% at December 31, 2005 and December 31, 2004, respectively.

As previously indicated, a significant portion of cash provided by operations consists of depreciation and amortization of utility plant which is recovered in rates. PGE estimates recovery of such charges to approximate $175 million to $215 million annually over the period 2006-2008. Combined with all other sources, cash provided by operations is estimated to range from $155 million to $295 million annually during the 2006-2008 period.

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

	2006	2007	2008
Capital expenditures (*)	$305 - $325	$225 - $245	$280 - $300
Long-term debt maturities	$11	$67	-

(*) Includes expenditures related to the construction of Port Westward (approximately $117 for 2006 and $16 for 2007) and for fish passage measures at the Pelton Round Butte hydroelectric project (approximately $50 for 2008).

PGE's revolving credit facility may be used to fund any potential cash shortfall, with additional liquidity available, if necessary, from the issuance of long-term debt. Cash balances are temporarily invested primarily in government money market funds and short-term commercial paper that have remaining maturities of less than three months from the date of acquisition and are considered cash equivalents. Such investments are consistent with PGE's investment objectives to preserve principal, maintain liquidity, and diversify risk. Company investments are limited to investment grade securities (primarily short-term).

In July 2005, PGE declared and paid a cash dividend of $150 million to Enron, the sole shareholder of the Company's common stock. PGE's equity ratio (as calculated under OPUC requirements) remains above the 48% level required by the Commission under terms of PGC's 1997 merger with Enron. PGE's common equity ratio also remains above the Company's 50% objective, as described above.

Following the issuance of new PGE common stock, currently expected to take place on or about April 3, 2006, the Company expects to pay regular quarterly common dividends. However, the declaration of common dividends is at the discretion of the 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.

Credit Ratings

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

PGE's current credit ratings are as follows:

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

Should Moody's or S&P (or both) reduce the credit rating on PGE's unsecured debt to below investment grade, the Company could be subject to requests by certain of its wholesale counterparties to post additional performance assurance collateral. On January 31, 2006, PGE had posted approximately $15 million of collateral, consisting of $11 million in letters of credit and $4 million in cash. Based on the Company's non-trading portfolio, estimates of current energy market prices, and the current level of collateral outstanding, as of January 31, 2006, the approximate amount of additional collateral that could be requested upon a single agency downgrade event to below investment grade is approximately $56 million and decreases to approximately $1 million by year-end 2006. The approximate amount of additional collateral that could be requested upon a dual agency downgrade event to below investment grade is approximately $68 million and decreases to approximately $1 million by year-end 2006.

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

Contractual Obligations and Commercial Commitments

The following indicates PGE's contractual obligations as of December 31, 2005 (in millions):

	Payments Due (*)						
	Total	2006	2007	2008	2009	2010	After 2010
Long-Term Debt	$ 890	$ 11	$ 67	$ -	$ -	$ 335	$ 477
Interest on Long-Term Debt	253	59	56	54	54	30	-
Operating Leases	216	7	7	7	7	7	181
Purchase Obligations	404	192	43	54	33	10	72
Purchased Power and Fuel:							
Electricity Purchases	1,926	706	304	90	90	91	645
Capacity Contracts	240	24	24	24	24	24	120
Natural Gas Agreements	138	35	17	17	15	13	41
Public Utility Districts	88	7	7	8	8	7	51
Coal and Transportation Agreements	55	13	13	14	3	3	9
Total	$4,210	$1,054	$ 538	$ 268	$ 234	$ 520	$1,596

(*) Interest on long-term debt is not estimated beyond 2010. Contributions to the Company's pension plan are estimated at $0 for 2006 through 2010 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 will 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 will be allocated up to a cumulative maximum of 25% of the defaulting purchaser's percentage Allocation. For the Priest Rapids project, PGE will be allocated up to a cumulative maximum of 7% of the total project.

For details of annual costs by project, including debt service, see Note 7, Commitments and Guarantee, in the Notes to the Financial Statements.

Off-Balance Sheet Arrangements

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

Critical Accounting Policies and Estimates

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

Regulatory Accounting

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

PGE continues to meet each of above conditions for continued application of SFAS No. 71 in its financial statements. The Company is subject to jurisdiction of the OPUC, which approves PGE's retail rates, ensuring that they provide an opportunity for the Company to earn a fair return on its investment. The Company's rates, as authorized by the OPUC, are based on the cost of service and are designed to recover operating expenses and capital costs associated with generation, transmission and distribution assets used to provide regulated service to customers. Although changes in such rates are subject to a formal ratemaking process, it is expected that the OPUC will continue to recognize all prudently-incurred costs and authorize rates that allow for their recovery. In addition, the OPUC has authorized an RVM process by which base rates are adjusted annually for changes in projected power costs. The RVM has enabled the Company to more timely reflect changes in power costs in customer prices. (For further information, see "Resource Valuation Mechanism" in "Financial and Operating Outlook" of this Item 7). Finally, PGE's retail operations are conducted within a state-approved service area in which there is no retail competition, other than that related to the state's customer choice program. Participation in this program, implemented in 2002, has not had a material impact on PGE's regulated operations, with only about 7% of the Company's total retail load served by ESSs. The large majority of PGE's customers continue to take service under rate tariffs determined by the cost of service. Changes in demand and level of competition for PGE's regulated services have not materially impacted the Company's ability to recover its costs through regulation.

PGE periodically assesses the continued applicability of SFAS No. 71 to its business, considering both the current and anticipated future rate environment and related accounting guidance, as outlined in SFAS No. 101, Regulated Enterprises - Accounting for the Discontinuation of Application of SFAS No. 71, and EITF Issue 97-4, Deregulation of the Pricing of Electricity - Issues Related to the Application of SFAS No. 71 and SFAS No. 101. As PGE continues to fully meet each of the required conditions, the Company has recorded regulatory assets and liabilities in the amount of $217 million and $524 million, respectively, at December 31, 2005. PGE expects to fully recover these regulatory assets, and refund these regulatory liabilities, through its rates. If future recovery of costs ceases to be probable, however, PGE would be required to write off these regulatory assets and liabilities. In addition, if at some point in the future PGE determines that all or a portion of its utility operations no longer meet the criteria for continued application of SFAS No. 71, the Company would be required to adopt the provisions of SFAS No. 101, which would require the Company to write off those regulatory assets and liabilities related to operations that no longer meet requirements of SFAS No. 71. Discontinuation of SFAS No. 71 could have a material impact on the Company's results of operations and financial position.

Asset Retirement Obligations

SFAS No. 143, as interpreted by FASB Interpretation No. 47, requires the recognition of Asset Retirement Obligations (AROs), measured at estimated fair value, for legal obligations related to dismantlement and restoration costs associated with the retirement of tangible long-lived assets in the period in which the liability is incurred. Upon initial recognition of AROs that are measurable, the probability weighted future cash flows for the associated retirement costs, discounted using a credit-adjusted risk-free rate, are recognized as both a liability and as an increase in the capitalized carrying amount of the related long-lived assets. Due to the long lead time involved, a market-risk premium cannot be determined for inclusion in future cash flows. Capitalized asset retirement costs are depreciated over the life of the related asset, with accretion of the ARO liability classified as an operating expense on the Statement of Income. On the Statement of Income, AROs related to Utility plant are included in Depreciation and Amortization expense, with those related to Other property included in Other Income (Deductions). In accordance with requirements of SFAS No. 143, accumulated asset retirement removal costs that do not qualify as AROs have been reclassified from Accumulated depreciation to Regulatory liabilities on the Balance Sheet.

Trojan Decommissioning

In early 1993, PGE ceased commercial operation of Trojan and began the decommissioning process. The original Trojan decommissioning cost estimate was prepared by an engineering firm with subsequent updates by PGE, due primarily to the effects of inflation and the timing of certain activities. The net estimated liability for Trojan decommissioning costs as of December 31, 2005 was $107 million, measured at estimated fair value pursuant to provisions of SFAS No. 143. PGE's current retail prices include recovery of $14 million annually through 2011, which amount is based on the decommissioning cost estimate. These amounts are deposited in an external trust fund, which reimburses PGE for costs expended under the decommissioning plan. The decommissioning estimate includes amounts for equipment removal, embedded pipe remediation, surface decontamination, non-radiological decontamination, and on-site spent nuclear fuel storage (until permanent storage is provided by the USDOE). Estimating the cost of decommissioning activities over a period extending to 2023 is inherently subjective and complex. Such estimates may vary because of changes in regulatory requirements, technology, labor and material costs, and waste burial. In addition, timing of actual activities may differ from that established in the decommissioning plan, which may also cause actual costs to vary from those estimated. Remaining decommissioning activities consist of demolition of the existing structures and long-term operation and decommissioning of the Independent Spent Fuel Storage Installation.

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

Loss Contingency Reserves

Contingencies are evaluated based on SFAS No. 5, Accounting for Contingencies, using the best information available. A material loss contingency is accrued and disclosed when it is probable that an asset has been impaired or a liability incurred and the amount of the loss can be reasonably estimated. If a range of possible loss is established, the minimum amount in the range is accrued, unless some other amount within the range appears to be a better estimate. If the probable loss cannot be reasonably estimated, no accrual is recorded, but the loss contingency is disclosed to the effect that it cannot be reasonably estimated. Material loss contingencies are disclosed when it is reasonably possible that an asset has been impaired or a liability incurred. Reserves established reflect management's assessment of inherent risks, credit worthiness, and complexities involved in the collection process.

Receivables and Refunds - California Wholesale Market

As of December 31, 2005, PGE has net accounts receivable balances totaling approximately $63 million for wholesale electricity sales made to the California Independent System Operator (ISO) and the California Power Exchange (PX) from November 2000 through February 2001. The Company estimates that the majority of this amount was for sales by the ISO and PX to Southern California Edison Company and Pacific Gas & Electric Company (PG&E). In 2001, the PX filed for bankruptcy and PG&E filed a voluntary petition for relief under the provisions of Chapter 11 of the federal Bankruptcy Code. Although both entities have emerged from their bankruptcy proceedings as reorganized debtors, not all claims filed in the proceedings, including those filed by PGE, have been resolved.

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

The FERC methodology for calculating potential refunds, initially established in July 2001, was revised in March 2003, significantly increasing the refund amount initially estimated. Accordingly, a $17.5 million reserve established at December 31, 2002 was increased to $40 million at December 31, 2003. Pursuant to FERC guidelines, PGE in September 2005 filed a cost recovery study to prove that the Company, in order to cover its costs, should be permitted to recover additional revenues in excess of the mitigated prices. The study showed that PGE's costs to serve the ISO and PX markets exceeded the revenues PGE will receive from those mitigated sales by over $27 million. By order issued January 26, 2006, the FERC conditionally accepted PGE's September cost filing, subject to PGE making a compliance filing to eliminate certain costs, to include additional revenues, and to supplement its analysis with additional cost, load, and resource data. On February 10, 2006, PGE submitted a compliance filing with two cases, in the alternative, that incorporated the FERC-required changes. The compliance filing shows a revenue deficit for PGE's sales to the ISO and PX (that is, a reduction to PGE's refund liability) of from approximately $20 million to approximately $30 million, depending on the methodology ultimately accepted by the Commission. Third parties have challenged PGE's compliance filing and requested that it be rejected in its entirety or that the cost offset be reduced to zero, and PGE has filed a response to those challenges. The procedure established by the FERC in the January 26 order also required each seller whose cost filing has been accepted to incorporate in its filing final ISO and PX settlement data and to provide its revised filing to the ISO and PX for further processing.

PGE believes that the FERC erred in certain of its findings in the January 26 order, and has filed a request for rehearing as to several issues. Due to the continuing uncertainty related to these matters, PGE has made no adjustment to the $40 million reserve previously established for the Company's potential liability. As an unresolved legal and regulatory matter, both the refund methodology and estimated amount may vary significantly in the future, which could have a material impact on PGE's results of operations.

Price Risk Management

PGE engages in price risk management activities in its electric business, utilizing derivative instruments such as electricity forward, swap, and option contracts and natural gas forward, swap, option, and futures contracts to protect the Company against variability in expected future cash flows due to associated price risk and to minimize net power costs for retail customers. Derivative contracts are accounted for under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended. Certain derivative instruments are recorded at fair value on the balance sheet and, to the extent these instruments are included in the Company's RVM, changes in fair value are offset with a regulatory asset or regulatory liability under SFAS No. 71 to reflect the effects of regulation. As these contracts are settled, the regulatory asset or regulatory liability is reversed. Until the settlement of all derivative instruments related to such activities, PGE will record changes in fair value in current earnings. Changes in fair value of instruments not included in the RVM are reflected in either income or comprehensive income. For further information, see "Resource Valuation Mechanism" in "Financial and Operating Outlook" of this Item 7.

Mark-to-Market

Marking a contract to market consists of reevaluating the market value at the end of each reporting period for the entire term of the contract and recording any change in value (difference between the contract price and current market price) in either earnings or other comprehensive income for the period. Valuation of these financial instruments reflects management's best estimates of market prices, including closing 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 Returns

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, and mortality rates. These assumptions are evaluated by PGE, reviewed annually with the plan actuaries and trust investment consultants, and updated in light of market changes, trends, and future expectations. Significant differences between assumptions and actual experience could have a material impact on PGE's financial condition and results of operations.

PGE's pension discount rate is based on assumptions regarding rates of return on long-term high quality bonds. Assumptions regarding the expected rate of return on plan assets are based on historical and projected average rates of return for current asset classes in the plan investment portfolio. The expected rate of return reflects expected future returns for the portfolio, and was used in determining net periodic pension income for the year. At December 31, 2005, the plan's assets were comprised of approximately 67% equity securities and 33% debt securities.

Changes in actuarial assumptions can also materially affect net periodic pension income. A 0.25% reduction in the expected long-term rate of return on plan assets would have reduced 2005 pension income by approximately $1.2 million. A 0.25% reduction in the discount rate would have reduced 2005 pension income by approximately $1.6 million.

In 2005, PGE updated the mortality rate assumptions used for pension benefits. The impact of this change was an increase of $14 million in the accumulated benefit obligation at December 31, 2005.

Transactions with Related Parties

PGE services to affiliated companies consist primarily of employee and administrative services. The Company also receives services from affiliated companies for certain insurance coverage. Transactions with affiliated companies are subject to regulation by the OPUC. Most affiliated interest transactions are made under a Master Service Agreement (MSA) filed with the Commission. Under OPUC regulations, services provided to affiliates by PGE are charged at the higher of cost or market, while affiliated services received by PGE are charged at the lower of cost or market.

Trading Activities Accounted for at Fair Value

PGE discontinued its trading activities in early 2005, with remaining transactions settled by December 31, 2005. Prior to discontinuance, PGE's trading activities utilized electricity forward, swap, and option contracts and natural gas forward, swap, option, and futures contracts to participate in electricity and natural gas markets. Valuation of these 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.

The following table indicates fair value, and changes in fair value, of PGE's trading contracts in 2005 and 2004 (in millions):

	Unrealized Gain (Loss)	
	2005	2004
Unrealized gain of contracts as of January 1	$ 1	$ -
Less contracts realized during year:		
Contracts entered in prior years	(1)	-
Contracts entered in current year	-	-
Change in fair value attributable to market changes:		
Contracts entered in prior years	-	-
Contracts entered in current year	-	1
Unrealized gain of contracts as of December 31	$ -	$ 1

Financial and Operating Outlook

Retail Customer Growth and Energy Deliveries

Weather adjusted retail energy deliveries to PGE and ESS customers increased 0.8% in 2005 compared to 2004. The increase was due primarily to 1.4% and 2.6% increases, respectively, for commercial and industrial customers. Increased industrial usage was largely attributable to a single large customer that normally generates its own power requirements, but which purchased energy from the Company during 2005. Weather adjusted residential energy deliveries were down 0.7% compared to 2004, as a reduction in average usage was only partially offset by an approximate 11,000 increase in the average number of customers served. PGE forecasts total weather adjusted energy deliveries to PGE and ESS customers to increase by approximately 2% in 2006.

Power and Fuel Supply

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

Early forecasts indicate that regional hydro conditions will approximate average levels in 2006. Volumetric water supply forecasts for the Pacific Northwest, prepared by the Northwest River Forecast Center in conjunction with the Natural Resources Conservation Service and other cooperating agencies, indicate the projected January-to-September 2006 runoff (as measured at The Dalles, Oregon) at 98% of normal, compared to actual runoffs of 74% in 2005 and 77% in 2004. In 2006, hydro conditions in the Clackamas and Deschutes river systems, where PGE's facilities are located, are currently projected to be 108% and 110% of normal, respectively, compared to actual runoffs of approximately 72% and 87% of normal, respectively, in 2005.

Factors that could affect the availability and price of purchased power and fuel include weather conditions in the Northwest and Southwest, as well as the performance of major generating facilities in both regions. In addition, market prices for natural gas increased significantly in 2005 due to the combined effects of severe hurricanes in the Gulf of Mexico and record hot weather in the United States. Such price increases could, in the longer term, affect the cost of natural gas required to fuel PGE's combustion turbine generating plants as well as prices of power purchased in the wholesale market.

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

From the time prices are set in the RVM process until the end of the RVM period, any changes to electricity and natural gas prices used in the RVM will result in unrealized gains and losses to be recorded in earnings in the current period on existing and new derivative instruments that do not qualify for the normal purchases and normal sales exception or cash flow hedges. Price movements in electricity and natural gas markets cause PGE to make power and natural gas purchases and sales decisions around the economic dispatch of its own generation. Derivative instruments that qualify for the normal purchases and normal sales exception or cash flow hedges, and forecasted transactions related to these decisions are not recorded in earnings in the current period, but are recognized in earnings when the contracts are settled in future periods. As a result, this timing difference may create earnings volatility between reporting periods.

Future Ownership of PGE

Enron's Chapter 11 Plan became effective on November 17, 2004. Although PGE was not included in the bankruptcy, the common stock of PGE held by Enron is one of the assets of the bankruptcy estate. Under the Chapter 11 Plan, Enron will distribute new PGE common stock to the Debtors' creditors. Current PGE common stock held by Enron will be cancelled and 62,500,000 shares of new PGE common stock without par value will be distributed over time to the Debtors' creditors. Initially, PGE will issue at least 30 percent of the new PGE common stock to the Debtors' creditors that hold allowed claims, with the remainder issued to a Disputed Claims Reserve (DCR) where it will be held to be released over time to the Debtors' creditors holding allowed claims in accordance with the Chapter 11 Plan.

The issuance of new PGE common stock is expected to take place on or about April 3, 2006. Following issuance of the new PGE common stock to the Debtors' creditors and the DCR, PGE will no longer be a subsidiary of Enron.

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

The distribution of new PGE common stock has been approved by all required regulatory agencies. The OPUC order approving the distribution (OPUC Order) includes 17 conditions that relate to, among other things: maintenance of PGE's financial strength during the conclusion of the Enron bankruptcy process, certain indemnifications for PGE from Enron related to Enron employee benefit plans and taxes, certain service quality measures, and additional direct access options for commercial and industrial customers. The indemnification is expected to be included in a separation agreement between Enron and PGE, which is expected to be executed at the time of the issuance of new PGE common stock.

On February 10, 2006, the City of Portland appealed the OPUC Order in both the Marion County Circuit Court and the Oregon Court of Appeals. The City filed its appeals in both courts due to the jurisdictional uncertainty created by new Oregon law governing appeals of OPUC decisions. In its appeal to the Circuit Court, the City alleges that the OPUC made its decision on an inadequate record, failed to enter adequate findings in support of its decision, abused the discretion granted it by Oregon law, and based its decision on a statute that constituted an unlawful delegation from the Oregon Legislature. The City requests the OPUC Order be modified, reversed or remanded. In the Court of Appeals filing, the City alleges that it is an aggrieved party and asks for judicial review without further details. On February 23, 2006 the OPUC filed a Motion to Hold Case in Abeyance with the Marion

County Circuit Court in order to seek summary determination from the Court of Appeals regarding the proper court to hear the City's appeal. The City and other defendants to the action, including PGE, did not oppose the motion. The Circuit Court has not ruled on this motion.

On February 13, 2006, the URP filed with the OPUC an application for reconsideration of the OPUC Order. The URP requests that the OPUC reconsider its order in light of a new Oregon Statute (Senate Bill 408), governing the rate treatment of income taxes included by Oregon utilities in rates. The URP alleges the stock distribution would allow PGE to deconsolidate for income tax purposes and frustrate future rate benefits Senate Bill 408 would allegedly produce. On February 28, 2006, PGE, CUB, and the OPUC staff filed oppositions to URP's application for reconsideration. Also on February 28, 2006, the City filed in support of URP's application and added new grounds for reconsideration of the OPUC Order. PGE filed in opposition to the City's new grounds for reconsideration on March 13, 2006. The OPUC has 60 days from the filing of an application for reconsideration to act on the application or it is deemed denied.

PGE has filed an original listing application with the NYSE for the listing of the new PGE common stock under the ticker symbol POR.

Enron has also indicated that, in accordance with its ongoing efforts to maximize the value of the Enron bankruptcy estate, it will continue to consider credible offers to purchase PGE's common stock until the new PGE common stock is issued. Following issuance of the new PGE common stock, approval of any offer to purchase the new PGE common stock from the DCR will be the responsibility of the DCRO, in accordance with guidelines approved by the Bankruptcy Court.

Enron Bankruptcy

Commencing on December 2, 2001, and from time to time thereafter, Enron Corp., along with certain of its subsidiaries, filed to initiate bankruptcy proceedings under Chapter 11 of the federal Bankruptcy Code. Enron's Chapter 11 Plan became effective on November 17, 2004. The Chapter 11 Plan and the related disclosure statement provide information about Chapter 11 Plan and are available at Enron's website located at www.enron.com/corp/por and the Bankruptcy Court's website located at www.nysb.uscourts.gov and at the website maintained at the direction of the Bankruptcy Court at www.elaw4enron.com.

In addition to the bankruptcy, numerous shareholder and employee class action lawsuits have been initiated against Enron, its former independent accountants, legal advisors, executives, and board members. In addition, Enron has been investigated by several Congressional committees and state and federal regulators, including the FERC and the State of Oregon. PGE has been included in requests for documents related to Congressional and regulatory investigations, with which it is fully cooperating. In addition to these general effects, PGE may have potential exposure to certain liabilities and asset impairments as a result of Enron's bankruptcy. These are:

Pension Plans

The Pension Benefit Guaranty Corporation (PBGC) insures pension plans, including the Enron Corp. Cash Balance Plan (the Enron Plan) and the pension plans of other Debtors. Enron's management has informed PGE that the PBGC filed claims for unfunded benefit liabilities (the UBL Claims) with respect to the Enron Plan and the plans of the other Debtors (Pension Plans). Pursuant to an order of the Bankruptcy Court, Enron created a reserve fund equal to the amount of the maximum PBGC exposure, as delineated in the PBGC UBL Claims, of $321.8 million. This reserve provides security to the PBGC, and limits the possibility of the PBGC seeking to assert its UBL Claims against PGE and other Enron affiliates for any underfunding of the Pension Plans.

On June 3, 2004, the PBGC filed a complaint (PBGC Complaint) in the District Court for the Southern District of Texas against Enron seeking, among other things, termination of the Pension Plans. On September 12, 2005, in a joint hearing, the U.S. District Court for the Southern District of Texas, Houston Division (District Court) and the Bankruptcy Court approved a settlement (Settlement) with the PBGC and the plaintiffs in the class action litigation styled Pamela M. Tittle, et al, v. Enron Corp., et al, Civil Action No. H-01-3913, U.S. District Court for the Southern District of Texas, Houston Division (Tittle Action) and the United States Department of Labor (DOL) in the litigation styled Elaine L. Chao v. Enron Corp., et al. (DOL Action). Under the Settlement, the Tittle Action plaintiffs and the DOL will have a shared general unsecured claim of $356.25 million and receive distributions pursuant to Enron's Chapter 11 Plan. Further, as a result of the Settlement, the PBGC Complaint and all actions in the Bankruptcy Court on the PBGC claims against the Debtors with respect to the Pension Plans have been stayed and should, by the terms of the Settlement, be dismissed with prejudice and Enron is proceeding with the standard termination of the Pension Plans. As a result, any need for the PBGC to attempt to collect from PGE any liability related to the Enron Plan should be eliminated.

Income Taxes

Under U.S. Treasury Department regulations, each member of a consolidated group in any year is severally liable for the tax liability of the consolidated group for that year. PGE has been a member of the Enron consolidated tax group since July 2, 1997, except for the period from May 8, 2001 to December 23, 2002 when PGE was not a member and filed its own consolidated tax returns. Enron's consolidated tax returns for all years through 2001 have been examined by the IRS and settlement has been reached, eliminating any further assessment of tax, interest or penalties. Enron's consolidated tax returns for 2002 and 2003 are currently being examined by the IRS. PGE remains potentially severally liable for any portion of any claim allowed in the bankruptcy that the IRS does not collect from the Debtors, or that is not settled by the reduction of any refund due to Enron.

OPUC Stipulation

One of the conditions in the OPUC Order is that, upon the issuance of the new PGE common stock, Enron agrees to provide indemnification to PGE for, among other things, any liabilities related to Enron-sponsored employee benefit plans (including the Enron Plan) and any liabilities related to taxes that may be imposed as the result of PGE's membership in Enron's consolidated tax group. These indemnifications are expected to be included in a separation agreement between Enron and PGE, which is expected to be executed at the time of the issuance of new PGE common stock.

Management Assessment

PGE management believes that the possibility of a material liability to PGE related to the Enron Plan or any IRS assessment against the Enron consolidated group for income taxes, interest, and penalties is remote.

Energy Policy Act of 2005

EPAct 2005, signed into law on August 8, 2005, significantly revised the Federal Power Act and Natural Gas Act. It also changed certain provisions of the Public Utility Regulatory Policies Act of 1978 (PURPA) regarding qualifying facilities and enacted tax incentives for the development of renewable and cleaner-fuel electric generating resources and for other electric and gas related purposes. EPAct 2005 includes transmission and reliability measures, including a plan for mandatory reliability standards to be developed and enforced by an electric reliability organization, which would be under the FERC's jurisdiction. EPAct 2005 also gave the FERC enhanced oversight of power and transmission markets.

EPAct 2005 repealed PUHCA 1935 and enacted PUHCA 2005, effective February 8, 2006. Under PUHCA 2005, certain functions of the SEC are transferred to the FERC, including access to holding company books and records and determining the appropriate allocation of costs in certain affiliate transactions. In addition, PUHCA 2005 grants state regulatory commissions access to the books and records of holding companies and their subsidiaries if such access is necessary for the effective discharge of the state commission's jurisdictional responsibilities. In December 2005, the FERC issued its final rules implementing PUHCA 2005, which rules are now effective.

EPAct 2005 also modifies and expands the FERC's authority and review of proposed utility mergers and acquisitions and disposition of assets related to wholesale sales.

PGE does not expect EPAct 2005 to have a material impact on the Company's operations or financial results.

New Oregon Law - Utility Rate Treatment of Income Taxes

A new law, Oregon Senate Bill 408, seeks to adjust the way that PGE and most other Oregon investor-owned electric and gas utilities collect income taxes from ratepayers. Senate Bill 408 attempts to more closely match amounts collected under the ratemaking process with income taxes paid to governmental entities by investor-owned utilities or their consolidated group. It requires that utilities file reports with the OPUC by October 15 of 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. If the OPUC determines that the difference between the two amounts is greater than $100,000, the Commission is to require the utility to establish an "automatic adjustment clause" to adjust rates.

PGE's initial report was filed on October 14, 2005 for the calendar years 2002, 2003, and 2004, based on temporary rules established by the OPUC. The report indicated that, for each year, the difference between "taxes authorized to be collected" and "taxes paid" was greater than $100,000. However, under the law the first adjustment under the automatic adjustment clause applies only to taxes paid to units of government and collected from ratepayers on or after January 1, 2006.

Considerable uncertainty exists regarding the new law, with several issues subject to interpretation by the OPUC. In December 2005, Oregon's Attorney General issued an opinion that provides guidelines for implementation of the new law. PGE is participating in the Commission's comprehensive rule-making process. Until the Commission issues rules that implement the law, its impact on customers and utilities will be difficult to assess. In addition, it is expected that such rules may be challenged in the courts.

PGE continues to evaluate the potential effects of the new law. For the first quarter of 2006, PGE will continue to be a member of Enron's consolidated group for filing consolidated federal and state income tax returns. Based on the temporary rules, PGE anticipates that there will be material differences between taxes "authorized to be collected" and "taxes paid" in 2006, although the amount of those differences cannot be fully assessed until final rules are adopted. Accordingly, this could have a material adverse affect on the Company's earnings in 2006.

On December 30, 2005, PGE filed with the OPUC an "Application for Deferred Accounting of Expenses Associated with Utility Tax Liability" to complement the automatic adjustment clause described above. The purpose of the proposed deferral is to prevent either the financial enrichment or financial harm to the Company that may occur if the permanent rules in Senate Bill 408 are designed with the use of fixed reference points for margins and effective tax rates from a rate making proceeding. The deferred amount would reflect the tax effect of the difference between PGE's implied operating costs under a fixed margin assumption and the Company's actual operating costs.

Complaint and Application for Deferral - Income Taxes

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

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

On December 27, 2005, the OPUC issued a Joint Ruling to hold the Complaint and Deferred Accounting application in abeyance pending rehearing of an order previously issued by the OPUC in a rate proceeding involving another Oregon electric utility. Management cannot predict the ultimate outcome of these matters or estimate any potential loss.

Class Action Lawsuit - Multnomah County Business Income Taxes

In January 2005, David Kafoury and Kafoury Brothers, LLC filed a class action lawsuit in Multnomah County Circuit Court against PGE on behalf of all PGE customers who were billed on their electric bills and paid amounts for Multnomah County Business Income Taxes (MCBIT) after 1996. The plaintiffs alleged that during the period 1997 through the third quarter 2004, PGE collected in excess of $6 million from its customers for MCBIT that was never paid to Multnomah County. The charges were billed and collected under OPUC rules that allow utilities to collect taxes imposed by the county. As a member of Enron's consolidated income tax return, PGE paid the tax it collected to Enron. The plaintiffs sought judgment against PGE for restitution of MCBIT collected from customers plus interest, recoverable costs, and reasonable attorney fees. The plaintiffs filed an amended complaint in February 2005, adding claims for fraud, unjust enrichment, conversion, statutory violations, and seeking punitive damages.

In May 2005, the Court granted PGE's motion for a stay for all purposes until the OPUC's issuance of a declaratory ruling in response to questions by PGE as to whether OPUC rules authorized PGE collections of the MCBIT and whether any refunds to customers were controlled by an OPUC three-year limitation for billing adjustments. In October 2005, the OPUC issued an order that determined that Commission rules authorized PGE collections of the MCBIT from Multnomah County customers but did not require that PGE calculate them in any particular way. Because the OPUC did not find that PGE had violated its rule, the Commission did not answer whether its three-year limitation on billing adjustments applied.

On December 28, 2005, the parties agreed to a settlement by which PGE will make refunds and payments totaling $10 million, inclusive of interest and plaintiffs' attorney fees, costs, and expenses as approved by the Court's final order. The settlement includes no admission of liability or wrongdoing by PGE. Distribution to customers is limited to amounts collected during the period 1999 through 2005. PGE established a reserve of $10 million in 2005 related to the settlement. The settlement is subject to final approval by the Multnomah County Circuit Court following a hearing currently scheduled for late July 2006.

City of Portland Investigation

In September 2005, the Portland City Council approved a resolution directing the City Attorney and City staff to obtain from PGE information regarding the collection and payment of utility income taxes. The City has stated that it believes its City Charter provides it with authority for this request. PGE voluntarily provided extensive financial and operational data to the City. The City has since broadened its inquiry to include PGE's power trading activities in 2000 and 2001 and has requested that PGE provide many additional documents and records. PGE has determined that there are a number of legal and practical issues concerning the City's request for additional information, and has declined to provide any additional data to the City while those issues remain unresolved.

General Rate Case

On March 15, 2006, PGE filed new tariffs with the OPUC seeking a 1.7% average increase in electric rates related to general (non-power) costs, to be effective January 1, 2007. In addition, the filing includes a 2.9% average increase for recovery of PGE's investment in the Port Westward natural gas generating plant, effective on the date the plant begins commercial operation. The filing also contains an estimated rate adjustment related to PGE's RVM tariff (described below). Due largely to increases in the cost of natural gas and power purchases, PGE currently estimates an average 4.1% rate increase related to the RVM, to become effective on January 1, 2007. The RVM process requires that PGE update this estimate as the year progresses, with final forecasts due in early November 2006.

The filing proposes a return on common equity of 10.75% (based on an expected capital structure of approximately 56% equity and 44% debt) and an allowed rate of return of 8.97% on debt and equity capital. Proposed price increases are estimated to result in an approximate $143 million increase in annual revenues.

In order to protect both PGE and its customers from power cost volatility and to allow customers a greater opportunity to share the benefits of any future savings in power costs, the Company is also proposing a tariff under which it would share with customers 90% of the difference between each year's forecast and actual net variable power costs. The annual update of prices to reflect changes in net variable power costs, as provided under the RVM, would continue.

Review of PGE's filing by the OPUC, including a detailed analysis of the Company's projected costs and proposed rate structure, is expected to take from nine to ten months and will include input from stakeholders and the public.

Resource Valuation Mechanism

The general rate order issued by the OPUC in 2001 approved an RVM tariff mechanism that requires annual updates of PGE's net variable power costs for inclusion in base rates for the following year. Developed in compliance with guidelines for Oregon's energy restructuring law that allow businesses direct access to energy service suppliers, the RVM utilizes a combination of market prices and the value of the Company's resources to establish power costs and set prices for energy services. It provides for an adjustment, finalized in mid-November each year, that is effective on January 1 of the following year.

Power Cost Price Decrease - 2003 PGE's first annual revision of its power supply costs under the RVM tariff forecasted a reduction in the cost of power from that included in the Company's 2001 general rate case. Accordingly, the OPUC authorized an approximate 7% average reduction in the Company's retail prices for 2003. Price decreases ranged from 2% for residential customers to between 9% and 17% for commercial and industrial customers, which were affected more by a reduction in wholesale energy market prices. These price decreases reduced PGE's 2003 revenues by approximately $90 million.

Power Cost Price Increase - 2004 Based upon projections in PGE's 2004 RVM filing, the OPUC authorized an approximate 0.4% average retail price increase for 2004. Price adjustments ranged from a 2.3% decrease for large non-residential customers to increases of 2.8% and 1.9% for small non-residential and residential customers, respectively. Price adjustments varied between customer classes primarily because of different collection periods for a power cost adjustment mechanism that was in effect for the period 2001-2002. Such adjustments increased PGE's 2004 revenues by approximately $4 million.

Power Cost Price Increase - 2005 Based upon projections in PGE's 2005 RVM filing, the OPUC authorized an approximate 1.4% average retail price increase for 2005. Price adjustments ranged from a 0.7% decrease for small non-residential customers to increases of 0.3% and 3.3% for residential and large non-residential customers, respectively. Such adjustments increased PGE's 2005 revenues by approximately $17 million.

Power Cost Price Increase - 2006 Based upon projections in PGE's 2006 RVM filing, the OPUC authorized an approximate 3.7% average retail price increase for 2006, due largely to substantial increases in the cost of wholesale power and continued high prices for natural gas. Increases (including the effect of all credits and adjustments) range from 1.7% for residential customers to 5.3% and 5.4%, respectively, for small and large non-residential customers. Such adjustments are expected to increase PGE's 2006 revenues by approximately $47 million.

Boardman Coal Plant - Extended Outage

On October 22, 2005, following the detection of vibrations in Boardman's steam turbine rotor, the plant was taken out of service. Following repeated unsuccessful efforts to return the plant to service, the rotor was removed and shipped to an east coast facility for repair. On February 6, 2006, during the process of returning the plant to operation, the generator rotor was damaged. The generator rotor has been removed for repairs. Although the actual time required to repair the generator rotor has not yet been determined, PGE estimates that Boardman will be operational by late April 2006. Due to the extended outage, annual maintenance requirements, originally scheduled for the second quarter of 2006, have been completed.

The extended outage has required that PGE replace its portion of Boardman's generation with both higher cost purchases in the wholesale market and increased generation from the Company's natural gas-fired generating plants. PGE's incremental power costs to replace its share of Boardman's generation in the fourth quarter of 2005 were estimated at $41 million, with first quarter 2006 incremental power costs estimated at $45 million. Estimated replacement power costs for April 2006 are expected to range from $200,000 to $300,000 per day. Incremental power costs related to the initial portion of the outage (October 23, 2005 through February 5, 2006) are estimated at $64 million, with incremental power costs related to the outage from February 6, 2006 to the end of the first quarter of 2006 currently estimated at $22 million.

On November 18, 2005, PGE filed with the OPUC an "Application for Deferred Accounting of Excess Power Costs Due to Plant Outage". The application requested an order authorizing PGE to defer for later ratemaking treatment excess power costs associated with Boardman's turbine rotor outage, effective on the date of the application. The application seeks deferral of the difference between Boardman's variable power costs used in setting rates for 2005 and 2006 (under the Company's RVM) and replacement power costs incurred during the turbine rotor outage. The deferral period for the outage ended on February 5, 2006 with the installation of the repaired turbine rotor. The deferral amount is currently estimated at approximately $45 million. No deferral was recorded in 2005. A procedural schedule has been adopted for further consideration of the deferral by the Commission. Management cannot predict the timing or the ultimate outcome of a decision by the OPUC on the Company's application. Under the RVM process, a 4-year rolling average of historical forced outages of PGE's generating plants is used in setting expected power costs. To the extent the Company is not allowed to recover replacement power costs for Boardman under the deferred accounting application, impacts of the turbine rotor forced outage (October 23, 2005 through February 5, 2006) may be included in the 4-year rolling average component of rates requested under the RVM process beginning in 2007.

PGE has determined that it will not file an application to defer incremental power costs related to the outage resulting from damage to the generator rotor, which began on February 6, 2006. The Company is evaluating, however, whether to propose including this outage in the 4-year rolling average of forced outages in its RVM filings starting in 2008.

Hydro Generation Adjustment

The effect of adverse hydro conditions in recent years has required that PGE acquire replacement power resources for shortfalls in hydro-based power, incurring substantially higher variable power costs than those included in the Company's electricity prices. In 2004, PGE requested OPUC consideration of a hydro generation adjustment tariff that would allow rate adjustment reflecting changes in power costs caused by variations in hydro conditions. The Company also filed an application to defer costs or benefits due to variances in hydro generation, beginning in 2005.

In 2005, PGE and OPUC Staff entered into stipulations for a mechanism that would defer for future recovery in rates a portion of power cost changes caused by variations in hydro conditions, power market prices, and natural gas prices during 2005 and 2006. Following hearings and consideration of the stipulations, the OPUC on December 21, 2005 issued an order that rejected the stipulations but left the dockets open and established criteria by which it would approve a hydro-related power cost adjustment mechanism. In February 2006, PGE withdrew its deferred accounting application and notified the OPUC that the Company will not pursue a hydro generation adjustment tariff, but has instead included a long-term general power cost adjustment mechanism in its current general rate case.

Port Westward Generating Plant

In February 2005, pursuant to PGE's strategy to meet the electric energy needs of its customers outlined in its Integrated Resource Final Action Plan, PGE began construction of Port Westward, a 400 MW natural gas-fired facility located in Clatskanie, Oregon. Construction is proceeding on schedule, with completion expected in the first quarter of 2007. Total cost of the plant is estimated between $275 million and $295 million (including AFDC).

Hydro Relicensing

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

Mid-Columbia Hydro Matters

PGE's long-term power purchase contracts with certain public utility districts in the state of Washington expire between 2009 and 2018. PGE has executed new agreements with Grant County Public Utility District (Grant), operator of the Priest Rapids and Wanapum projects, for periods corresponding to Grant's new license term, to be determined by the FERC. The Priest Rapids agreement became effective in November 2005 and the Wanapum agreement will become effective November 1, 2009. Both contracts, which are subject to approval of the FERC, extend through the life of Grant's new license. Under the agreements, Grant will annually determine the output required for its purposes, with PGE 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 will steadily decline as Grant's needs increase, with the Company's share in the two projects reduced from the current 189 MW to an estimated 151 MW in 2010. Also under the agreements, PGE will purchase an additional 49 average megawatts of power annually during the period 2006-2011.

In February 2005, the FERC approved a settlement between Douglas County PUD (Douglas), owner of the Wells Hydroelectric Project (Project), and the Colville Confederated Tribes (Colville Tribe) that resolved claims for charges for the use of Colville tribal lands. The settlement requires that Douglas pay a $13.5 million lump sum, convey certain real property, and allocate (at cost) 4.5% of Project's output to the Colville Tribe; such allocation increases to 5.5% for all years after 2018. To fund the $13.5 million payment, PGE and other purchasers of the Project's output entered into a Settlement Endorsement Agreement (Agreement) providing for the sale by Douglas of revenue bonds. The Agreement requires that each purchaser of the Project's output pay their respective share of debt service on the revenue bonds, with PGE's annual share calculated at approximately $350,000. In addition to its share of debt service payments, PGE's share of the Project's output was reduced from 20.3% to 19.4% beginning in April 2005. The effects of both the debt service requirement and the reduction in output were included in projected power costs in PGE's final 2005 and 2006 RVM filings approved by the OPUC.

For further information regarding PGE's power purchase contracts from mid-Columbia projects, see Note 7, Commitments and Guarantee, in the Notes to Financial Statements.

Trojan Investment Recovery

In 1993, following the closure of Trojan, 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. The filing was a result of PGE's decision earlier in the year to cease commercial operation of Trojan as a part of its least cost planning process. In 1995, the OPUC issued a general rate order (1995 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 requested reviews were subsequently filed in the Marion County Circuit Court, the Oregon Court of Appeals, and the Oregon Supreme Court on the issue of the OPUC's authority under Oregon law to grant recovery of, and a return on, the Trojan investment. The Oregon Court of Appeals issued an opinion in 1998, stating that the OPUC does not have the authority to allow PGE to recover a return on the Trojan investment, but upholding the OPUC's authorization of PGE's recovery of the Trojan investment and ordering remand of the case to the OPUC. PGE, the OPUC, and 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.

In 2000, while the petitions for review of the 1998 Court of Appeals decision were pending at the Oregon Supreme Court, PGE, CUB, and the staff of the OPUC entered into settlement agreements with respect to litigation over recovery of, and return on, the Trojan investment. The settlement agreements, approved by the OPUC in September 2000, allowed PGE to remove from its balance sheet the remaining before-tax investment in Trojan of approximately $180 million at September 30, 2000, along with several largely offsetting regulatory liabilities. The 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 rate making elements of the 2000 settlement. URP appealed the 2002 Order to the Marion County Circuit Court and on November 7, 2003, the Court issued an opinion remanding the case to the OPUC for action to reduce rates or order refunds. The opinion does not specify the amount or timeframe of any reductions or refunds. PGE and the OPUC have appealed to the Oregon Court of Appeals.

In a separate legal proceeding, two class action suits were filed in Marion County Circuit Court against PGE on January 17, 2003 on behalf of two classes of electric service customers. One case seeks to represent current PGE customers that were customers during the period from April 1, 1995 to October 1, 2001 (Current Class) and the other case seeks to represent PGE customers that were customers during the period from April 1, 1995 to October 1, 2001, but who are no longer customers (Former Class, together with the Current Class, the Class Action Plaintiffs). The suits seek damages of $190 million for the Current Class and $70 million for the Former Class, as a result of the inclusion of a return on investment of Trojan in the rates PGE charges its customers. On April 28, 2004, the plaintiffs (Class Action Plaintiffs) filed a Motion for Partial Summary Judgment and on July 30, 2004, PGE also moved for Summary Judgment in its favor on all of Class Action Plaintiffs' claims. On December 14, 2004, the Judge granted the Class Action Plaintiffs' motion for Class Certification and Partial Summary Judgment and denied PGE's motion for Summary Judgment. PGE filed a proposed order certifying the issue for an interlocutory appeal. An order rejecting the proposed order was entered on February 1, 2005. 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 May 3, 2005, the Oregon Supreme Court granted both Petitions. Briefing and arguments have been completed and a decision is pending.

On March 3, 2004, the OPUC re-opened three dockets in which it had addressed the issue of a return on PGE's investment in Trojan, including the 1995 Order and 2002 Order related to the settlement of 2000.

On August 31, 2004, the administrative law judge issued an Order (Scoping Order) defining the scope of the proceedings necessary to comply with the Marion County Circuit Court orders remanding this matter to the OPUC. On October 18, 2004, the OPUC affirmed the Scoping Order. On December 20, 2004, the URP and Class Action Plaintiffs filed an application with the OPUC for reconsideration of the Scoping Order. On February 11, 2005, the OPUC denied reconsideration and on April 18, 2005, URP and Linda K. Williams filed a complaint against the OPUC in Marion County Circuit Court challenging the OPUC's affirmation of the Scoping Order. The OPUC filed a motion to dismiss the complaint, and on September 21, 2005, the Marion County Circuit Court granted the OPUC's motion. Hearings in the first phase of the OPUC proceeding have been held and a decision is pending.

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

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

Nuclear Decommissioning

PGE has completed all radiological decommissioning activities at Trojan and, upon approval of the NRC, the plant's operating license was terminated on May 23, 2005. Previously, the steam generator, reactor containment vessel, and other major components were removed and transported to a licensed low level radioactive waste disposal facility in Washington State for permanent storage. Spent nuclear fuel has been stored in the Independent Spent Fuel Storage Installation (ISFSI), an interim dry storage facility that houses the fuel at the plant site until permanent off-site storage is available. Spent fuel storage activities will continue to be subject to NRC regulation until all nuclear fuel is removed from the site, decontamination is completed, and the storage installation is fully decommissioned. Remaining decommissioning activities consist of demolition of the existing structures (including the plant's cooling tower and those buildings that once housed the plant's turbine, reactor, and spent fuel pool) and long-term operation and decommissioning of the ISFSI.

PGE has recorded an ARO for Trojan decommissioning of $107 million, measured at estimated fair value, as of December 31, 2005. The ARO estimate assumes that the majority of decommissioning activities were completed at the end of 2005, with remaining costs extending through 2024. The plan anticipates final site restoration activities will begin in 2023 after PGE completes shipment of spent fuel to a USDOE facility. Decommissioning expenditures are estimated at $11 million for 2006, compared to $4 million in 2005.

In 2002, the USDOE formally recommended Yucca Mountain, Nevada as the nation's first long-term geologic (underground) repository for high-level radioactive waste produced in the United States. The proposed location is based on the conclusions of scientific studies of the site, conducted over 20 years, which support a finding of suitability as mandated by the Nuclear Waste Policy Act and various regulations of the NRC, USDOE, and the EPA. The House and Senate approved the site and in 2002, President Bush signed the Yucca Mountain resolution into law. Lawsuits have been filed objecting to the recommendation of Yucca Mountain as a nuclear waster repository. Based upon updated information received from the USDOE regarding the acceptance of spent nuclear fuel from Trojan, PGE has extended its projection for the final shipment of spent fuel from 2018 to 2023. The USDOE has not yet submitted to the NRC the required application for an operating license for the repository. Further delays may make it difficult for PGE to move its spent nuclear fuel, currently contained in the ISFSI, to permanent underground storage by 2023.

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

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

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

Receivables and Refunds on Wholesale Market Transactions

Receivables - California Wholesale Market

As of December 31, 2005, PGE has net accounts receivable balances totaling approximately $63 million from the California ISO and the PX for wholesale electricity sales made from November 2000 through February 2001. The Company estimates that the majority of this amount was for sales by the ISO and PX to Southern California Edison Company and Pacific Gas & Electric Company (PG&E).

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

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

Refunds on Wholesale Transactions

California - On July 25, 2001, the FERC issued an order establishing the scope of and methodology for calculating refunds for wholesale sales transactions made between October 2, 2000 and June 20, 2001 in the spot markets operated by the ISO and PX. The order established evidentiary hearings to develop a factual record to provide the basis for the refund calculation. Several additional orders clarifying and further defining the methodology have since been issued by the FERC. Appeals of the FERC orders were filed and in August 2002 the U.S. Ninth Circuit Court of Appeals issued an order requiring the FERC to reopen the record to allow the parties to present additional evidence of market manipulation.

Also in August 2002, the FERC Staff issued a report that included a recommendation that natural gas prices used in the methodology to calculate potential refunds be reduced significantly, which could result in a material increase in PGE's potential refund obligation.

In December 2002, a FERC administrative law judge issued a certification of facts to the FERC regarding the refunds, based on the methodology established in the 2001 FERC order rather than the August 2002 FERC Staff recommendation. On March 26, 2003, the FERC issued an order in the California refund case (Docket No. EL00-95) adopting in large part the certification of facts of the FERC administrative law judge but adopting the August 2002 FERC Staff recommendation on the methodology for the pricing of natural gas in calculating the amount of potential refunds. PGE estimates its potential liability under the modified methodology at between $40 million and $50 million, of which $40 million has been established as a reserve, as discussed above.

Numerous parties, including PGE, filed requests for rehearing of various aspects of the March 26, 2003 order, including the methodology for the pricing of natural gas. On October 16, 2003, the FERC issued an order reaffirming, in large part, the modified methodology adopted in its March 26, 2003 order. PGE does not agree with the FERC's methodology for determining potential refunds and, on December 20, 2003, the Company appealed the FERC's October 16, 2003 order to the U.S. Ninth Circuit Court of Appeals; several other parties have also appealed the October 16, 2003 order. On May 12, 2004, the FERC issued an order that denied further requests for rehearing of the October 16, 2003 order. Although there continue to be miscellaneous orders issued in the underlying FERC proceeding, the Ninth Circuit Court of Appeals has now begun to hear the numerous appeals. It has bifurcated appeals of the existing cases into two phases. The first considered arguments regarding jurisdictional issues and the permissible scope of refund liability, both in terms of the time frame for which refunds were ordered and the types of transactions subject to refund. Briefing and oral argument have been completed on this first phase. As to the jurisdictional issues, on September 6, 2005, the Court ruled that FERC did not have jurisdiction to order municipal utilities and other governmental entities to make refunds for the sales they had made to the ISO and PX that are the subject of the refund proceeding. The Court has not yet issued a decision on the other issues pending in the first phase, and the Court agreed to defer the rehearing deadline on the jurisdictional issue decision until the remainder of the first phase is decided. The second phase will consider the issues relating to the refund methodology itself. PGE expects that the Court will establish additional phases as the continuing issues remaining before FERC become final and are appealed.

Also on May 12, 2004, the FERC issued a separate order that provided clarification regarding certain aspects of the methodology for California generators to recover fuel costs incurred to generate power that were in excess of the gas cost component used to establish the refund liability. On September 24, 2004, the FERC issued an order that denied requests for rehearing of its May 12, 2004 fuel cost order and also adopted a new methodology to allocate the excess amounts of fuel costs that

California generators are permitted to recover. Additional clarifying orders continue to be issued periodically. Under the new allocation methodology of the September 24, 2004 order, PGE could be required to pay additional amounts in those hours when it was a net buyer in California spot markets, thus increasing its net refund liability. PGE does not expect that this order will materially increase the Company's potential refund exposure. Partly as a means of limiting its exposure to additional fuel costs, PGE has opted to become a participant in several settlements filed jointly by large generators and California parties, and approved by the FERC during 2004 and 2005.

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

In several of its underlying refund orders, the FERC has indicated that if marketers, such as PGE, believe that the level of their refund liability has caused them to incur an overall revenue shortfall for their sales to the ISO and PX during the refund period, they will be permitted to file a cost study to prove that they should be permitted to recover additional revenues in excess of the mitigated prices in order to cover their costs. By order issued August 8, 2005, FERC provided guidelines regarding the manner in which these studies should be conducted and the principles that should govern their preparation. PGE filed for rehearing of certain aspects of the August 8 order, and, on September 14, it filed its cost recovery study with FERC. The study showed that, pursuant to the principles set forth in the August 8 order and subject to rehearing, PGE's costs to serve the ISO and PX markets exceeded the revenues PGE will receive from those mitigated sales by over $27 million. By order issued January 26, 2006, the FERC conditionally accepted PGE's September 14 cost filing, subject to PGE making a compliance filing to eliminate certain costs, to include additional revenues, and to supplement its analysis with additional cost, load, and resource data. On February 10, 2006, PGE submitted a compliance filing with two cases, in the alternative, that incorporated the FERC-required changes. The compliance filing shows a revenue deficit for PGE's sales to the ISO and PX (that is, a reduction to PGE's refund liability) of from approximately $20 million to approximately $30 million, depending on the methodology ultimately accepted by the Commission. Third parties have challenged PGE's compliance filing and requested that it be rejected in its entirety or that the cost offset be reduced to zero, and PGE has filed a response to those challenges. The procedure established by the FERC in the January 26 order also required each seller whose cost filing has been accepted to incorporate in its filing final ISO and PX settlement data and to provide its revised filing to the ISO and PX for further processing.

PGE believes that the FERC erred in certain of its findings in the January 26 order, and has filed a request for rehearing as to several issues. Due to the continuing uncertainty related to these matters, PGE has made no adjustment to the $40 million reserve previously established for the Company's potential liability, as described above.

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

Challenge of the California Attorney General to Market-Based Rates - On March 20, 2002, the California Attorney General filed a complaint with the FERC against various sellers in the wholesale power market, alleging that the FERC's authorization of market-based rates violated the 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 during the period October 2, 2000 - June 4, 2002 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 Court of Appeals. On September 8, 2004, the Court issued an opinion upholding the FERC's authority to approve market-based tariffs, but also holding that the FERC had the authority to order refunds, if quarterly filing of market-based sales transactions had not been properly made. The Court required the FERC, upon remand, to reconsider whether refunds should be ordered. On October 25, 2004, certain parties filed a petition for rehearing with the Court. In the refund case and in related dockets, the California Attorney General and other California parties have argued that refunds should be ordered retroactively to at least May 1, 2000. Management cannot predict the outcome of these proceedings or whether the FERC will order refunds retroactively to May 1, 2000, and if so, how such refunds would be calculated.

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

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

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

Union Grievances

In November 2001, grievances were filed by several members of the International Brotherhood of Electrical Workers Local 125 (IBEW), the bargaining unit representing PGE's union workers, alleging that losses in their pension/savings plan were caused by Enron's manipulation of its stock. The grievances, which do not specify an amount of claim, seek binding arbitration. PGE filed for relief in

Multnomah County Circuit Court seeking a ruling that the grievances are not subject to arbitration. On August 14, 2003, the Court granted PGE's motion for summary judgment, finding that the grievances are not subject to arbitration. A final judgment was entered on October 6, 2003. On October 22, 2003, the IBEW appealed the decision to the Oregon Court of Appeals. Both the U.S. District Court and the Bankruptcy Court approved the settlement of the class action litigation styled In re Enron Corp. Securities Derivative & "ERISA" Litigation, Pamela M. Tittle, et al, v. Enron Corp., et al, Civil Action No. H-01-3913, U.S. District Court for the Southern District of Texas, Houston Division (Tittle Action). On September 13, 2005, the U.S. District Court entered a Bar Order in the Tittle Action, which specifically bars all claims arising out of this case including the IBEW grievance proceeding. On October 18, 2005, at the request of the Oregon Court of Appeals, PGE filed a response memorandum in which PGE argued that the Bar Order makes the grievance moot. A decision is pending. Management cannot predict the ultimate outcome of this matter or estimate any potential loss.

Colstrip Plant - Royalty Claim

Western Energy Company (WECO) transports coal from the Rosebud Mine in Montana under a Coal Transportation Agreement with owners of Colstrip Units 3 and 4, in which PGE has a 20% ownership interest. In 2002 and 2003, WECO received two orders from the Office of Minerals Revenue Management of the U.S. Department of the Interior which asserted underpayment of royalties and taxes by WECO related to transportation of coal from the mine to Colstrip. 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 Appeals Division of the MMS denied in part, and granted in part, the appeals by WECO. 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 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. No formal demand has been issued to date. Based upon review of the Coal Transportation Agreement, the Colstrip owners believe they have reasonable defenses against any claims for such royalties and taxes. PGE is monitoring these processes.

Environmental Matters

Harborton

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

In 1999, the DEQ asked that PGE perform a voluntary remedial investigation of its Harborton Substation site to confirm whether any hazardous substances had been released from the substation property into the Portland Harbor sediments. In May 2000, the Company entered into a "Voluntary Agreement for Remedial Investigation and Source Control Measures" (the Voluntary Agreement) with the DEQ, in which the Company agreed to complete a remedial investigation at the Harborton site under terms of the agreement.

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

In March 2001, in accordance with the Voluntary Agreement, PGE submitted a final investigation plan to the DEQ for approval. DEQ approved the plan and in June 2001 PGE performed initial investigations and remedial activities based upon the approved investigation plan. The investigations have shown no significant soil or groundwater contaminations with a pathway to the river sediments from the Harborton site.

In February 2002, PGE submitted its final investigative report to the DEQ summarizing its investigations conducted in accordance with the May 2000 Voluntary Agreement. The report indicated that such voluntary investigation demonstrated that there is no likely present or past source or pathway for release of hazardous substances to surface water or sediments in the Portland Harbor Superfund Site at or from the Harborton Substation site. Further, the voluntary investigation demonstrated 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 final investigative report to the EPA and in a May 18, 2004 letter, the EPA stated that "Based on the summary information provided by DEQ and the limited data EPA has at this stage in its process, EPA agrees at this time, that this 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 it is terminating the Voluntary Agreement, which is deemed to be satisfied. The DEQ further stated that "Based on our review of existing information and our understanding of current site conditions, DEQ determined that the site is not likely a current source of contamination to the river and that the site is a low priority for further action." Management believes that the Company's contribution to the sediment contamination, if any, from the Harborton Substation site would qualify it as a de minimis Potentially Responsible Party.

Sufficient information is currently not available to determine either the total cost of investigation and remediation of the Portland Harbor or the liability of Potentially Responsible Parties, including PGE. Management cannot predict the ultimate outcome of this matter. However, it believes this matter will not have a material adverse impact on its financial statements.

Harbor Oil
Harbor Oil, Inc. (Harbor Oil), located in north Portland, was utilized by PGE to process used oil from the Company's power plants and electrical distribution system from at least 1990 until 2003. Harbor Oil is also utilized by many 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 petroleum products, metals, pesticides, and polychlorinated biphenyl's (PCBs), have been detected at the site. On September 29, 2003, following investigation and site assessment by the EPA, Harbor Oil was included on the federal National Priority List as a federal Superfund site.

PGE received a Special Notice Letter for Remedial Investigation/Feasibility Study from the EPA, dated June 27, 2005, in which the Company was named as one of fourteen PRPs with respect to the Harbor Oil site. The letter starts a period for PRPs to participate in negotiations with the EPA to reach a settlement to conduct or finance a Remedial Investigation and Feasibility Study of the Harbor Oil site. Discussions among the EPA and the PRPs, including PGE, have commenced.

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

Other
In October 2003, PGE agreed with the DEQ to provide cost recovery for oversight of a voluntary investigation and/or potential cleanup of petroleum products at another Company site that is upland from the Portland Harbor Superfund Site. The site investigation has been completed and a report was submitted to the DEQ in August 2005. The report concludes that fuel and related contaminants have not migrated to the Willamette River from the site. The DEQ has stated that it is satisfied with the report. PGE management considers any material liability related to this matter to be remote.

Colstrip Plant
In December 2003, PPL Montana, LLC (PPL Montana), the operator of the Colstrip coal-fired generating plants, received an Administrative Compliance Order (ACO) from the EPA pursuant to the Clean Air Act (CAA). The EPA alleges that since 1980, Colstrip Units 3 and 4, in which PGE has a 20% ownership interest, have been in violation of the clean air permit issued under the CAA. The permit requires Colstrip Units 3 and 4 to submit, for review and approval by the EPA, an analysis and proposal for reducing nitrogen oxide emissions to address visibility concerns if and when the EPA establishes requirements for such emissions. The EPA asserts that regulations it established in 1980 triggered the requirement. PPL Montana is currently negotiating a consent decree with the EPA to resolve this matter, which would include penalties (if any) that may be assessed.

In addition to the ACO, the EPA has issued an information request with respect to the Colstrip units. The EPA is investigating whether older coal-fired plants have been modified over the years in a manner that would subject them to more stringent requirements under the CAA. Based on the settlement discussions with PPL Montana on the ACO, the EPA has indicated that it will not pursue this information request.

A local Native American tribe had asserted that sulfur dioxide emissions from Colstrip Units 3 and 4 are affecting local tribal areas more than previously estimated. PPL Montana has agreed to stricter sulfur dioxide emission limits in a recently approved Title V air permit for Colstrip, effectively resolving this matter.

New Accounting Standards
SFAS No. 123R (SFAS 123R), Share-Based Payment, was issued in December 2004 and replaces SFAS No. 123, Accounting for Stock-Based Compensation. Companies that issue share-based payment awards to employees are required to recognize compensation expense based on the fair value of the expected vested portion of the award as of the grant date over the vesting period of the award. Forfeitures that occur before the award vesting date will be adjusted from the total compensation expense, but once the award vests, no adjustment to compensation expense will be allowed for forfeitures or unexercised awards. In addition, SFAS 123R would require recognition of compensation expense of all existing outstanding awards that are not fully vested for their remaining vesting period as of the effective date that were not accounted for under a fair value method of accounting at the time of their award. SFAS 123R is effective for annual reporting periods beginning after June 15, 2005. PGE had no outstanding equity awards at December 31, 2005 and is evaluating the impact of the application of SFAS 123R and SEC Staff Accounting Bulletin No. 107 with respect to any future equity awards granted by the Company.

FASB Staff Position No. FAS 13-1 (FSP 13-1), Accounting for Rental Costs Incurred during a Construction Period, addresses the accounting for rental costs associated with ground and building operating leases that are incurred during a construction period. FSP 13-1 requires that rental costs associated with ground or building operating leases incurred during a construction period be recognized as rental expense and included in income from continuing operations. The application of FSP 13-1, which is required in the first reporting period beginning after December 15, 2005, is not expected to have a material effect on the financial statements of the Company.

Information Regarding Forward-Looking Statements

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

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

In addition to other factors and matters discussed elsewhere in this report, some important factors that could cause actual results or outcomes for PGE to differ materially from those discussed in forward-looking statements include:

- matters and events related to Enron and certain of its subsidiaries' bankruptcy proceedings under Chapter 11 of the federal Bankruptcy Code (PGE is not included in the filing);

- events related to the distribution of new PGE common stock to the Debtors' creditors who hold allowed claims and to the Disputed Claims Reserve;

- effects of electric industry restructuring in Oregon and in the United States, including retail and wholesale competition;

- governmental policies and regulatory investigations and actions, including those of the FERC and OPUC with respect to allowed rates of return, financings, electricity pricing and rate structures, acquisition and disposal of assets and facilities, operation and construction of plant facilities, recovery of net variable power costs and other capital investments, and present or prospective wholesale and retail competition;

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

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

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

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

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

- operational factors affecting PGE's power generation facilities;

- increasing national and international concerns regarding global warming and proposed regulations that could result in requirements for additional pollution control equipment or significant emissions fees or taxes, particularly with respect to coal-fired generation facilities, to mitigate carbon dioxide and other gas emissions;

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

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

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

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

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

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

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

- legal and regulatory proceedings and issues;

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

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

- terrorist activities.

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

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

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

Commodity Price Risk

PGE's primary business is to provide electricity to its retail customers. The Company uses both long- and short-term purchased power contracts to supplement its thermal and hydroelectric generation to respond to fluctuations in the demand for electricity and variability in generating plant operations. In meeting these needs, PGE is exposed to market risk arising from the need to purchase power and to purchase fuel for its natural gas and coal fired generating units. The Company uses instruments such as forward contracts, which may involve physical delivery of an energy commodity, swap agreements, which may require payments to (or receipt of payments from) counterparties based on the differential between a fixed and variable price for the commodity, options, and futures contracts to mitigate risk that arises from market fluctuations of commodity prices.

Gains and losses from non-trading instruments that reduce commodity price risks are recognized when settled in Purchased Power and Fuel expense, or in wholesale revenue. Gains and losses on instruments used for trading purposes are recognized on a net basis within Operating Revenues on PGE's income statement. (Trading activities were discontinued in early 2005, with existing trading transactions settled by December 31, 2005). 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 portfolios using a value at risk methodology, which measures the potential losses in fair value due to the impact of market movements over a one-day holding period using a variance/covariance approach at a 95% confidence interval. The portfolio is modeled using net open power and natural gas positions, with power averaged over peak and off-peak periods by month, and includes all financial and physical positions for the next 24 months, including estimates of retail load and plant generation in the non-trading portfolio. The risk factors include commodity prices for power and natural gas at various locations and do not include volumetric variability. Based on this methodology, the average, high, and low value at risk on the non-trading portfolio in 2005 were $3.8 million, $9.7 million, and $1.8 million, respectively, in 2004 were $1.4 million, $3.1 million, and $0.6 million, respectively, and in 2003 were $2.0 million, $3.7 million, and $1.0 million, respectively.

PGE's non-trading activities are subject to regulation. The timing differences between the recognition of gains and losses on certain derivative instruments and their realization and subsequent recovery in prices are deferred as regulatory assets and regulatory liabilities to reflect the effects of regulation under SFAS No. 71. As contracts are settled, these deferrals reverse. In its non-trading value at risk, PGE does not reflect any amount of these potential deferrals under SFAS No. 71.

Foreign Currency Exchange Rate Risk
PGE has exposure to foreign currency risk associated with natural gas forward and swap contracts denominated in Canadian dollars in its non-trading portfolio. Foreign currency risk is the risk of changes in value of pending financial obligations in foreign currencies that could occur prior to the settlement of the obligation due to a change in the value of that foreign currency in relation to the U.S. dollar. PGE monitors its exposure to fluctuations in the Canadian exchange rate with an appropriate hedging strategy.

Beginning in 2003, PGE implemented a strategy that utilizes forward contracts to acquire Canadian dollars in order to mitigate its currency exposure. At December 31, 2005, 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
Although PGE had no short-term debt outstanding at December 31, 2005, the Company is typically exposed to risk resulting from changes in interest rates on variable rate short-term borrowings. The Company has also had exposure to interest rate changes on variable rate commercial paper. Although PGE currently has no financial instruments to mitigate such risk, 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	2006	2007	2008	2009	2010	After 2010
First Mortgage Bonds	$ 558	$520	$ -	$50	$ -	$ -	$150	$320
Pollution Control Revenue Bonds (*)	200	194	-	-	-	-	37	157
Other	192	176	11	17	-	-	148	-
Total	$ 950	$890	$11	$67	$ -	$ -	$335	$477

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

For detail of debt by category, see Note 5, Credit Facilities and Debt, in the Notes to Financial Statements.

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

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, 2005, the likelihood of significant losses associated with credit risk for trade accounts receivable is remote.

The following table presents PGE's credit exposure for commodity non-trading activities and their subsequent maturity as of December 31, 2005. The table reflects credit risk included in accounts receivable and price risk management assets, offset by related accounts payable and price risk management liabilities.

Non-Trading Activities

(Dollars in millions)

				Maturity of Credit Risk Exposure					
Rating	**Credit Risk Before Collateral**	**Percentage of Total Exposure**	**Credit Collateral**	**2006**	**2007**	**2008**	**2009**	**2010**	**After 2010**
Investment Grade	$ 238	95%	$ 110	$ 121	$ 60	$ 28	$ 9	$ 7	$ 13
Non-Investment Grade	8	3%	8	8	-	-	-	-	-
Internally Rated - Investment Grade	4	2%	-	4	-	-	-	-	-
Total	$ 250	100%	$ 118	$ 133	$ 60	$ 28	$ 9	$ 7	$ 13

Investment Grade includes those counterparties with a minimum credit rating on senior unsecured debt of Baa3 (as assigned by Moody's) or BBB- (as assigned by S&P), and also those counterparties whose obligations are guaranteed or secured by an investment grade entity. Non-Investment Grade includes those counterparties with below investment grade credit ratings on senior unsecured debt. For non-rated counterparties, PGE performs credit analysis to determine an internal credit rating that approximates investment or non-investment grade. Included in this analysis is a review of counterparty financial statements, specific business environment, access to capital, and indicators from debt and capital markets. The credit exposure includes activity for electricity and natural gas forward, swap, and option contracts. Posted collateral may be in the form of cash or letters of credit and may represent prepayment or credit exposure assurance.

Omitted from the non-trading market risk exposures above are long-term power purchase contracts with certain public utility districts in the State of Washington and with the City of Portland, Oregon. These contracts provide PGE with a percentage share of hydro facility output in exchange for an equivalent percentage share of operating and debt service costs. These contracts expire at varying dates through 2018. Management believes that circumstances that could result in the nonperformance by these counterparties are remote.

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 8, Price Risk Management, in the Notes to Financial Statements.

Item 8. Financial Statements and Supplementary Data

Management's Responsibility for Financial Reporting

The following financial statements of Portland General Electric Company and its subsidiaries (collectively, PGE) were prepared by management, which is responsible for their integrity and objectivity. The statements have been prepared in conformity with accounting principles generally accepted in the United States of America and necessarily include some amounts that are based on the best estimates and judgments of management.

PGE maintains a system of internal control over financial reporting, which encompasses policies, procedures, and controls designed to provide reasonable assurance as to the reliability of the financial statements and for the protection of assets from unauthorized acquisition, use or disposition. This system is augmented by the careful selection and training of qualified personnel. It should be recognized, however, that there are inherent limitations in the effectiveness of any system of internal control. Accordingly, even an effective system of internal control over financial reporting can provide only reasonable assurance with respect to the preparation of reliable financial statements and safeguarding of assets. Further, because of changes in conditions, internal control system effectiveness may vary over time.

PGE also has disclosure controls and procedures that are designed to ensure that information required to be disclosed in reports filed under the Securities Exchange Act of 1934 (Exchange Act) is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission (SEC). The disclosure controls and procedures are also designed to ensure that information required to be disclosed is accumulated and communicated to PGE management, including its Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

The adequacy of PGE's internal controls, disclosure controls and procedures, and the accounting principles applied in financial reporting are under the general oversight of the Audit Committee of PGE's Board of Directors.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of Portland General Electric Company:

We have audited the accompanying consolidated balance sheets of Portland General Electric Company and subsidiaries (the "Company") as of December 31, 2005 and 2004, and the related consolidated statements of income, retained earnings, comprehensive income, and cash flows for each of the three years in the period ended December 31, 2005. Our audits also included the financial statement schedule listed in Item 15 (a). These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes 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, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Portland General Electric Company and subsidiaries as of December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, 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 financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

As discussed in Notes 1 and 11 to the consolidated financial statements, in 2003 the Company changed its method of accounting for asset retirement obligations and its presentation of operating revenues and operating expenses associated with non-trading electric derivative activities.

As discussed in Note 16 to the consolidated financial statements, the accompanying 2004 and 2003 financial statements have been restated.

Deloitte & Touche LLP
Portland, Oregon
March 14, 2006

Portland General Electric Company and Subsidiaries
Consolidated Statements of Income

For the Years Ended December 31	2005	2004	2003 (As Restated - See Note 16)
		(In Millions)	
Operating Revenues	$1,446	$1,454	$1,752
Operating Expenses			
Purchased power and fuel	671	667	1,028
Production and distribution	128	127	117
Administrative and other	168	148	148
Depreciation and amortization	233	233	213
Taxes other than income taxes	74	72	72
Income taxes	46	57	50
	1,320	1,304	1,628
Net Operating Income	126	150	124
Other Income (Deductions)			
Miscellaneous	3	8	5
Income taxes	3	3	6
	6	11	11
Interest Charges			
Interest on long-term debt and other	68	69	79
Net Income before cumulative effect of a change in accounting principle	64	92	56
Cumulative effect of a change in accounting principle, net of related taxes of $(3)	-	-	4
Net Income	64	92	60
Preferred Dividend Requirement	-	-	1
Income Available for Common Stock	$ 64	$ 92	$ 59

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

Portland General Electric Company and Subsidiaries
Consolidated Statements of Retained Earnings

For the Years Ended December 31	2005	2004	2003
		(In Millions)	
Balance at Beginning of Year (restated, see Note 16)	$ 644	$ 552	$ 493
Net Income (restated, see Note 16)	64	92	60
	708	644	553
Dividends Declared			
Common stock	150	-	-
Preferred stock	-	-	1
	150	-	1
Balance at End of Year	$ 558	$ 644	$ 552

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

Portland General Electric Company and Subsidiaries
Consolidated Statements of Comprehensive Income

For the Years Ended December 31	2005	2004	2003 (As Restated - See Note 16)
		(In Millions)	
Accumulated other comprehensive income (loss) - Beginning of Year			
Unrealized gain (loss) on derivatives classified as cash flow hedges	$ (2)	$ 2	$ 3
Minimum pension liability adjustment	(4)	(4)	(3)
Total	$ (6)	$ (2)	$ -
Net Income	$ 64	$ 92	$ 60
Other comprehensive income, net of tax:			
Unrealized gains (losses) on derivatives classified as cash flow hedges:			
Other unrealized holding gains arising during the period, net of related taxes of $(18) in 2005, $(8) in 2004, and $(5) in 2003	28	12	9
Reclassification adjustment for contract settlements included in net income, net of related taxes of $(3) in 2005, $4 in 2004, and $1 in 2003	4	(6)	(3)
Reclassification adjustment in net income due to discontinuance of cash flow hedges, net of related taxes of $1 in 2005 and $6 in 2003	(1)	-	(9)
Reclassification of unrealized gains (losses) to SFAS No. 71 regulatory (liability) asset, net of related taxes of $19 in 2005, $6 in 2004, and $(2) in 2003	(29)	(10)	2
Total - Unrealized gains (losses) on derivatives classified as cash flow hedges	2	(4)	(1)
Minimum pension liability adjustment	1	-	(1)
Total Other comprehensive income (loss)	3	(4)	(2)
Comprehensive income	$ 67	$ 88	$ 58
Accumulated other comprehensive income (loss) - End of Year			
Unrealized gain (loss) on derivatives classified as cash flow hedges	$ -	$ (2)	$ 2
Minimum pension liability adjustment	(3)	(4)	(4)
Total	$ (3)	$ (6)	$ (2)

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

Portland General Electric Company and Subsidiaries
Consolidated Balance Sheets

At December 31	2005	2004 (As Restated - See Note 16)
	(In Millions)	
Assets		
Electric Utility Plant - Original Cost		
Utility plant (includes construction work in progress of $177 and $114)	$ 4,224	$ 3,992
Accumulated depreciation	(1,788)	(1,717)
	2,436	2,275
Other Property and Investments		
Nuclear decommissioning trust, at market value	31	22
Non-qualified benefit plan trust	69	64
Miscellaneous	34	30
	134	116
Current Assets		
Cash and cash equivalents	122	204
Accounts and notes receivable (less allowance for uncollectible accounts of $50 and $50)	203	170
Unbilled revenues	78	80
Assets from price risk management activities	259	77
Inventories, at average cost	54	48
Prepayments and other	24	35
	740	614
Deferred Charges and Other		
Regulatory assets	217	295
Miscellaneous	111	103
	328	398
	$ 3,638	$ 3,403
Capitalization and Liabilities		
Capitalization		
Common stock equity		
Common stock, $3.75 par value per share, 100,000,000 shares authorized, 42,758,877 shares outstanding	$ 160	$ 160
Other paid-in capital - net	482	481
Retained earnings	558	644
Accumulated other comprehensive income (loss):		
Unrealized gain (loss) on derivatives classified as cash flow hedges	-	(2)
Minimum pension liability adjustment	(3)	(4)
Limited voting junior preferred stock	-	-
Long-term debt	879	892
	2,076	2,171
Commitments and Contingencies (see Notes)		
Current Liabilities		
Long-term debt due within one year	11	30
Accounts payable and other accruals	260	173
Liabilities from price risk management activities	129	38
Customer deposits	53	18
Accrued interest	17	19
Accrued taxes	42	37
Deferred income taxes	51	15
	563	330
Other		
Deferred income taxes	218	313
Deferred investment tax credits	10	13
Trojan asset retirement obligation	107	96
Accumulated asset retirement obligation	27	24
Regulatory liabilities:		
Accumulated asset retirement removal costs	349	286
Other	175	74
Non-qualified benefit plan liabilities	79	70
Miscellaneous	34	26
	999	902
	$ 3,638	$ 3,403

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

Portland General Electric Company and Subsidiaries
Consolidated Statements of Cash Flow

For the Years Ended December 31	2005	2004	2003 (As Restated - See Note 16)
		(In Millions)	
Cash Flows From Operating Activities:			
Reconciliation of net income to net cash provided by operating activities			
Net income	$ 64	$ 92	$ 60
Non-cash items included in net income:			
Cumulative effect of a change in accounting principle, net of tax	-	-	(4)
Depreciation and amortization	233	233	213
Deferred income taxes	(53)	(13)	(22)
Net assets from price risk management activities	(40)	(7)	(30)
Power cost adjustment	18	40	51
Other non-cash income and expenses (net)	44	16	19
Changes in working capital:			
Net margin deposit activity	35	13	-
(Increase) Decrease in receivables	(29)	43	9
Increase (Decrease) in payables	82	(61)	21
Other working capital items - net	4	(22)	(6)
Other - net	14	6	(4)
Net Cash Provided by Operating Activities	372	340	307
Cash Flows From Investing Activities:			
Capital expenditures	(255)	(194)	(167)
Purchases of nuclear decommissioning trust securities	(34)	(31)	(30)
Sales of nuclear decommissioning trust securities	21	32	28
Other - net	(4)	9	(9)
Net Cash Used in Investing Activities	(272)	(184)	(178)
Cash Flows From Financing Activities:			
Repayment of long-term debt	(32)	(61)	(402)
Issuance of long-term debt	-	-	342
Debt issue costs	-	-	(7)
Preferred stock retired	-	-	(3)
Dividends paid	(150)	-	(1)
Net Cash Used in Financing Activities	(182)	(61)	(71)
Increase (Decrease) in Cash and Cash Equivalents	(82)	95	58
Cash and Cash Equivalents, Beginning of Period	204	109	51
Cash and Cash Equivalents, End of Period	$ 122	$ 204	$ 109
Supplemental disclosures of cash flow information			
Cash paid during the period:			
Interest, net of amounts capitalized	$ 58	$ 62	$ 67
Income taxes	88	83	39
Non-cash investing and operating activities:			
Accrued capital additions	9	9	8

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

Nature of Operations

PGE is a single, integrated electric utility engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the State of Oregon. The Company also sells wholesale electric energy to utilities, brokers, and power marketers located throughout the western United States. PGE operates as a single segment, with revenues and costs related to its business activities maintained and analyzed on a total electric operations basis. PGE's service area is located entirely within Oregon and includes 52 incorporated cities, of which Portland and Salem are the largest, within a state-approved service area allocation of approximately 4,000 square miles. At the end of 2005, PGE's service area population was approximately 1.5 million, comprising about 43% of the state's population. The Company served approximately 780,000 retail customers at December 31, 2005.

On July 2, 1997, Portland General Corporation (PGC), the former parent of PGE, merged with Enron Corp., with Enron Corp. continuing in existence as the surviving corporation. On December 2, 2001, Enron Corp., along with certain of its subsidiaries, filed to initiate bankruptcy proceedings under Chapter 11 of the federal Bankruptcy Code. PGE was not included in the filing, but the common stock of PGE is one of the assets of the bankruptcy estate. On November 17, 2004, the 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 (Chapter 11 Plan), became effective. PGE is currently a wholly-owned subsidiary of reorganized Enron Corp. (Enron).

In accordance with the Chapter 11 Plan, Enron plans to distribute PGE common stock to the creditors of Enron and its reorganized debtor subsidiaries (jointly the Debtors) holding allowed claims. Current PGE common stock will be cancelled and 62,500,000 shares of new PGE common stock without par value will be distributed over time to Debtors' creditors holding allowed claims. Initially, at least 30 percent of the new PGE common stock will be issued by PGE to the Debtors' creditors that hold allowed claims, with the remainder issued to a Disputed Claims Reserve (DCR), where it will be held to be released over time to the Debtors' creditors holding allowed claims, in accordance with the Chapter 11 Plan. Following the issuance of the new PGE common stock (currently expected to take place on or about April 3, 2006), PGE will no longer be a subsidiary of Enron. Distribution of new PGE common stock has been approved by the required regulatory agencies, including the OPUC and the FERC. However, the City of Portland has appealed the OPUC decision and the Utility Reform Project has filed for reconsideration by the OPUC. See Note 15, Future Ownership of PGE, for further information.

Note 1 - Summary of Significant Accounting Policies

Consolidation Principles

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

Basis of Accounting

PGE and its subsidiaries' financial statements conform to accounting principles generally accepted in the United States. In addition, PGE's accounting policies are in accordance with the requirements and the rate making practices of regulatory authorities having jurisdiction. PGE's consolidated financial statements do not reflect an allocation of the purchase price that was recorded by Enron as a result of the PGC merger.

Use of Estimates

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

Contingencies

Contingencies are evaluated based on Statement of Financial Accounting Standards (SFAS) No. 5, Accounting for Contingencies, using the best information available. A material loss contingency is accrued and disclosed when it is probable that an asset has been impaired or a liability incurred and the amount of the loss can be reasonably estimated. If a range of possible loss is established, the minimum amount in the range is accrued, unless some other amount within the range appears to be a better estimate. If the probable loss cannot be reasonably estimated, no accrual is recorded, but the loss contingency is disclosed to the effect that the probable loss cannot be reasonably estimated. A material loss contingency will be disclosed when it is reasonably possible that an asset has been impaired or a liability incurred. Gain contingencies are recognized upon realization and are disclosed when material.

Reclassifications

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

Revenues

Retail revenues are recognized when monthly billings are made for energy sold to customers and delivered to those customers that purchase their energy from Energy Service Suppliers (ESSs). 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 power 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 liquidity risk, counterparty non-performance risk, and contractual rights of offset when applicable. Actual amounts written off are charged to the allowance for uncollectible accounts.

In certain situations, PGE defers the recognition of revenues until the period in which the related costs are incurred, in accordance with the provisions of SFAS No. 71, 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 deferred under the Company's power cost adjustment mechanisms (described under "Power cost adjustment mechanisms" under "Regulatory Assets and Liabilities" in this Note), as well as amortization of such amounts as recovery is made from customers;

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 7, Commitments and Guarantee); and, 3) Provisions related to wholesale accounts receivable and unsettled positions (described under "Revenues" in this Note).

Price Risk Management

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

Non-Trading

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

The OPUC, which regulates PGE's retail electricity business, recognizes non-trading contracts only at the time of settlement. Contracts that qualify for the normal purchases and normal sales exception are not required to be recorded at fair value. Unrealized gains and losses from contracts that qualify as cash flow hedges are recorded net in OCI and contracts designated as non-hedges are recorded net in Purchased Power and Fuel expense on the Statement of Income. To reflect the effect of regulation, PGE records a regulatory asset or regulatory liability under SFAS No. 71 to offset unrealized gains and losses on certain non-trading contracts recorded prior to settlement to the extent that such changes are included in the Company's Resource Valuation Mechanism (RVM). The regulatory asset or regulatory liability is reflected within Regulatory assets or Regulatory liabilities, respectively, on the Balance Sheet. Upon settlement, the regulatory asset or regulatory liability is reversed.

Sales and purchases involving non-trading electricity derivative activities that are physically settled are recorded in Operating Revenues and Purchased Power and Fuel expense, respectively. Prior to October 1, 2003, non-trading electricity derivative activities that were "booked out" (not physically settled) were recorded on a "gross" basis in both Operating Revenues and Purchased Power and Fuel expense. Pursuant to the adoption of Emerging Issues Task Force Issue No. 03-11 (EITF 03-11) on October 1, 2003, PGE records book out activities on a net basis in Purchased Power and Fuel expense on a prospective basis.

Trading

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

For further information, see Note 8, Price Risk Management.

Customer Deposits

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

Capitalization of Property, Plant and Equipment

Additions to utility plant are capitalized at their original cost, consistent with accounting and regulatory guidelines. Costs include direct labor, materials and supplies, and contractor costs, as well as indirect costs such as engineering, supervision, employee benefits, and allowance for funds used during construction. Plant replacements are capitalized, with minor items charged to expense as incurred. The costs to purchase/develop software applications are capitalized in accordance with AICPA 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. For information regarding accounting for asset retirement obligations, see "Asset retirement obligations" and "Accumulated asset retirement removal costs" under "Regulatory Assets and Liabilities" in this Note.

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

	2005	2004
Production	$1,395	$1,376
Transmission	283	283
Distribution	1,954	1,856
General	239	243
Intangible	176	120
Construction Work in Progress	177	114
Total	$4,224	$3,992

Depreciation and Amortization of Property, Plant and Equipment

Depreciation is computed using the straight-line method over the estimated average service lives of various classes of plant in service. Classes of plant in service and their estimated service lives (in years) are as follows: Production (32), Transmission (55), Distribution (35), and General (13). Depreciation is based upon original cost and includes an estimate for cost of removal and expected salvage. Depreciation expense as a percent of the related average depreciable plant in service was approximately 4.4% in 2005, 4.5% in 2004, and 4.6% in 2003. Estimated asset retirement removal costs included in depreciation expense were $64 million, $61 million, and $58 million in 2005, 2004, and 2003, respectively.

Periodic studies are conducted to update depreciation parameters (i.e. retirement dispersion patterns, average service lives, and net salvage rates), including estimates of Asset Retirement Obligations (AROs) and asset retirement removal costs. The studies are conducted every five years and are filed with the OPUC for approval and inclusion in a future rate proceeding. The most recent study, which is included in PGE's pending general rate case filing, was filed with the OPUC in October 2005.

The original cost of depreciable property units, net of any related salvage value, is charged to accumulated depreciation when property is retired and removed from service. Cost of removal expenditures are charged to asset retirement obligations for assets with AROs and to accumulated asset retirement removal costs for assets without AROs. See Note 11, Asset Retirement Obligations, for further information.

Intangible plant, consisting primarily of computer software development and hydro re-licensing costs, is amortized over estimated average service lives or the applicable license term. Amortization expense for 2005, 2004, and 2003 was $13 million, $14 million, and $13 million, respectively, and is estimated at $15 million for 2006, $14 million for 2007, $11 million for 2008, and $10 million for both 2009 and 2010. Accumulated amortization was $76 million and $67 million at December 31, 2005 and December 31, 2004, respectively; the increase consists of the net amount of current year amortization expense less accumulated amortization on intangible plant retirements.

Major Maintenance Expenses

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

Allocations and Loadings

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

Allowance for Funds Used During Construction (AFDC)

AFDC represents the pre-tax cost of borrowed funds used for construction purposes and a reasonable rate for equity funds. It is capitalized as part of the cost of plant and is credited to income but does not represent current cash earnings. The average rates used by PGE in 2005, 2004, and 2003 were 9.0%. AFDC from borrowed funds was $4 million in 2005, and $3 million in 2004 and 2003. AFDC from equity funds was $8 million in 2005, $6 million in 2004, and $4 million in 2003.

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, 2005 and 2004 were $16 million and $19 million, respectively, and are classified within Deferred charges - Miscellaneous on the Balance Sheet.

Income Taxes

PGE's federal taxable income was included in Enron's consolidated federal income tax return from July 2, 1997, the date of the Company's merger with Enron, until May 7, 2001, when Enron determined that PGE would no longer be a member of the Enron consolidated federal income tax return. During this time, PGE paid Enron for net tax liabilities generated on the taxable income of PGE, less applicable tax credits. Beginning May 8, 2001, PGE and its subsidiaries filed their own consolidated federal tax return and paid their own tax liabilities directly to the Internal Revenue Service (IRS). PGE and its subsidiaries also filed unitary state income tax returns, and paid their own state tax liabilities, in accordance with the applicable state law; they were also included in some Enron and subsidiaries' unitary state income tax returns. On December 24, 2002, PGE and its subsidiaries again became a member of Enron's consolidated tax group. Upon the issuance of new PGE common stock (currently expected to take place on or about April 3, 2006), PGE and its subsidiaries will no longer be a member of Enron's consolidated return and will file their own consolidated tax returns and remit tax payments directly to taxing authorities. For further information, see Note 13, Related Party Transactions, and Note 15, Future Ownership of PGE.

Deferred income taxes are provided for temporary differences between financial and income tax reporting. Investment tax credits utilized have been deferred and are amortized to income over the approximate lives of the related properties, not to exceed 25 years. See Note 3, Income Taxes, for further information.

Cash and Cash Equivalents

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

Non-Qualified Benefit Plan Trust

The non-qualified benefit plan trust (rabbi trust) is comprised of insurance contracts and investments in money market, bond, and equity mutual funds. The cash surrender value of insurance contracts is reported as an asset at the end of the reporting period, with changes in such values between reporting periods recognized as income or expense of the period (see "Other Non-Qualified Benefit Plans" in Note 2, Employee Benefits, for further information). The cash surrender value of insurance contracts, the majority of which are held in the trust, was $22 million at December 31, 2005 and $20 million at December 31, 2004. The investments in marketable securities are classified as trading and recorded at fair value on the Balance Sheet. Realized and unrealized gains and losses on these investments (determined using average cost) are included in Other Income (Deductions) on the Statement of Income. Investments in marketable securities and cash totaled $47 million at December 31, 2005 and $44 million at December 31, 2004.

Inventories

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

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

	2005	2004
Coal	$ 11	$ 8
Fuel oil	11	11
Natural gas	4	3
Materials and supplies	25	24
Unallocated stores account	3	2
Total	$ 54	$ 48

Trojan Decommissioning Costs

Trojan decommissioning costs consist of those expenditures related to the decommissioning of the Trojan Nuclear Plant. The present value of estimated future decommissioning expenditures, which is revised periodically, is recorded as an ARO on the Balance Sheet, with actual expenditures charged to the ARO account as incurred. See Note 11, Asset Retirement Obligations, and Note 12, Trojan Nuclear Plant, for further information.

Regulatory Assets and Liabilities

PGE is subject to the provisions of SFAS No. 71. Accounting under SFAS No. 71 is appropriate as long as rates are established by or subject to approval by independent third-party regulators; rates are designed to recover the specific enterprise's cost of service; and in view of demand for service, it is reasonable to assume that rates set at levels that will recover costs can be charged to and collected from customers.

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

Unless otherwise noted, a return on the unamortized balance is recorded for regulatory assets and regulatory liabilities at PGE's authorized cost of capital of 9.083%.

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

	2005	2004
Regulatory assets:		
Trojan decommissioning costs	$ 75	$ 74
Income taxes recoverable	80	92
Prior tax benefits recoverable	1	10
Debt reacquisition costs	21	23
Conservation investments - secured	9	19
Energy efficiency programs	-	10
Power cost adjustment mechanism	-	19
Regulatory restructuring costs	16	20
Beaver 8	9	11
Pelton Round Butte tax benefits recoverable	-	3
Miscellaneous	6	14
Total	$217	$295
Regulatory liabilities:		
Asset retirement obligations	$ 21	$ 18
Accumulated asset retirement removal costs	349	286
Price risk management	130	45
Information technology costs	3	3
Trojan ISFSI pollution control tax credits	5	2
Oregon corporation excise tax refund	4	-
Miscellaneous	12	6
Total	$524	$360

Trojan decommissioning costs - PGE's current retail prices include recovery of $14 million annually through 2011 for costs to decommission Trojan (see Note 12, Trojan Nuclear Plant, for further information). These amounts represent the estimated fair value of the remaining regulatory asset to be recovered from customers.

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

Prior tax benefits recoverable - In 2000, PGE entered into settlement agreements related to the recovery of its investment in the Trojan plant. The agreements provided for removal from the Company's Balance Sheet of the remaining before-tax investment in Trojan, along with several largely offsetting regulatory liabilities. The settlement also allowed recovery of approximately $47 million in income taxes related to the Trojan investment which had been flowed to customers in prior years; such amount is being recovered from PGE customers, with no return on the unamortized balance, over an approximate five-year period. See Note 10, Legal and Environmental Matters, for further information.

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

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

Energy efficiency programs - PGE's energy efficiency program expenditures, formerly deferred and amortized, have been expensed directly since October 1, 2000. The unamortized balance of those expenditures incurred prior to October 1, 2000, as well as amounts recoverable under the Company's SAVE energy efficiency program and certain other energy efficiency costs, have been fully recovered from retail customers at December 31, 2005. Beginning March 1, 2002, energy efficiency program expenditures and amounts reimbursed from public purpose funds administered by the Energy Trust of Oregon are charged and credited, respectively, to Other Income (Deductions).

Power cost adjustment mechanism - In February 2001, the OPUC authorized PGE to defer for recovery from customers a portion of its net variable power costs in excess of a baseline amount during the period January through September 2001. The deferred amount was recovered over the period April 1, 2002 through December 31, 2005.

PGE did not have power cost adjustment mechanisms for 2004 and 2005 and currently has none in place for 2006.

Regulatory restructuring costs - The OPUC authorized PGE to defer certain costs related to implementation of Oregon's electric restructuring law. Approximately $7 million is currently being recovered in prices charged to customers over a six-year period that began on January 1, 2003, with a remaining balance of $3 million at December 31, 2005. The remaining $17 million in implementation costs is being recovered over a five-year period that began on January 1, 2004, with a remaining balance of $13 million at December 31, 2005.

Beaver 8 - In December 2004, the OPUC issued an Order that adopted a stipulation in which parties agreed that PGE may recover from customers approximately $14 million for costs associated with a 24.7 MW combustion turbine (referred to as Beaver 8) installed at the Company's Beaver generating plant site in 2001. Of this amount, $10 million (plus accrued interest) was deferred for recovery from customers over a five-year period beginning January 1, 2005. The remaining $4 million, representing the current market value of the turbine, remains in plant in service and is depreciated over its useful life. The plant costs are included in rate base in PGE's general rate case, filed with the OPUC in March 2006.

Pelton Round Butte tax benefits recoverable - In 2002, PGE sold a 33.33% interest in the Pelton Round Butte hydroelectric project for PGE's net book value, in accordance with an agreement approved by the OPUC. The sales price did not include recovery of approximately $5 million in income tax benefits that had been flowed to customers in prior years. The OPUC authorized PGE to defer the income taxes recoverable for future rate recovery. Such recovery was completed over a two-year period that began on January 1, 2004.

Asset retirement obligations - SFAS No. 143, Accounting for Asset Retirement Obligations, which was adopted on January 1, 2003, requires the recognition of AROs, measured at estimated fair value, for legal obligations related to dismantlement and restoration costs associated with the retirement of tangible long-lived assets in the period in which the liability is incurred. Pursuant to regulation, AROs of rate-regulated long-lived assets are included as an allowable cost in rates charged to customers. Any differences in the timing of recognition of costs for financial reporting and ratemaking purposes are deferred as a regulatory asset or regulatory liability under SFAS No. 71. Asset retirement obligations are included in PGE's rate base for ratemaking purposes.

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

Price risk management - SFAS No. 133 requires unrealized gains and losses on derivative instruments that do not qualify for the normal purchase and normal sale exception to be recorded in earnings and other comprehensive income in the current period. To reflect the effects of regulation under SFAS No. 71, timing differences between the recognition of gains and losses on certain non-trading derivative instruments and their realization and subsequent recovery in rates are recorded as regulatory assets or regulatory liabilities. Amounts recorded by PGE at December 31, 2005 and 2004 offset the effects of such gains and losses, which are caused by changes in fair values of related energy contracts; recorded amounts are reversed as such contracts are settled. See Note 8, Price Risk Management, for further information.

Information technology costs - In PGE's 2001 general rate filing, the OPUC approved an estimated amount of capital expenditures related to the Company's Customer Information System (CIS) and Information Technology (IT) activities in the determination of PGE's 2002 revenue requirement. The Commission's rate order stipulated that PGE's retail customers are to receive a refund if the actual revenue requirement for such costs is less than the estimated revenue requirement. Accordingly, regulatory liabilities of $4 million were recorded in 2005, 2004, and 2003, to reflect the difference between actual and estimated revenue requirements related to CIS and IT capital expenditures. Amounts deferred are being refunded to customers through 2006. A $4 million annual deferral will continue until new base rates are established.

Trojan ISFSI Pollution Control Tax Credits - In December 2004, PGE received final certification from the Oregon Environmental Quality Commission (OEQC) related to $21.1 million in Oregon pollution control tax credits that were generated from PGE's investment in an Independent Spent Fuel Storage Installation (ISFSI) at Trojan. OEQC rules require that the tax credits be spread over a ten-year period, beginning in 2004. The OPUC approved the deferral of the tax credits for future ratemaking treatment. See Note 12, Trojan Nuclear Plant, for further information.

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

Recovery/refund period - As of December 31, 2005, the majority of PGE's regulatory assets and liabilities are reflected in customer rates. Based on such rates, the Company 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 14 years.

New Accounting Standards

FASB Interpretation No. 47 (FIN 47), Accounting for Conditional Asset Retirement Obligations - an interpretation of FASB Statement No. 143, was issued in March 2005 and is effective no later than the end of fiscal years ending after December 15, 2005. FIN 47 clarifies that the term "conditional asset retirement obligation" as used in FASB Statement No. 143, Accounting for Asset Retirement Obligations, refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. An entity is required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated, even though uncertainty exists about the timing and (or) method of settlement. PGE's adoption of FIN 47 on December 31, 2005 did not have a material effect on the financial statements of the Company.

FASB Staff Position No. FAS 13-1 (FSP 13-1), Accounting for Rental Costs Incurred during a Construction Period, addresses the accounting for rental costs associated with ground and building operating leases that are incurred during a construction period. FSP 13-1 requires that rental costs associated with ground or building operating leases incurred during a construction period be recognized as rental expense and included in income from continuing operations. The application of FSP 13-1, which is required in the first reporting period beginning after December 15, 2005, is not expected to have a material effect on the financial statements of the Company.

SFAS No. 123R (SFAS 123R), Share-Based Payment, was issued in December 2004 and replaces SFAS No. 123, Accounting for Stock-Based Compensation. Companies that issue share-based payment awards to employees are required to recognize compensation expense based on the fair value of the expected vested portion of the award as of the grant date over the vesting period of the award. Forfeitures that occur before the award vesting date will be adjusted from the total compensation expense, but once the award vests, no adjustment to compensation expense will be allowed for forfeitures or unexercised awards. In addition, SFAS 123R would require recognition of compensation expense of all existing outstanding awards that are not fully vested for their remaining vesting period as of the effective date that were not accounted for under a fair value method of accounting at the time of their award. SFAS 123R is effective for annual reporting periods beginning after June 15, 2005. PGE had no outstanding equity based awards at December 31, 2005 and is evaluating the impact of the application of SFAS 123R and SEC Staff Accounting Bulletin No. 107 with respect to any future equity awards granted by the Company.

Note 2 - Employee Benefits

Pension and Other Post-Retirement Plans

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

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

In December 2005, PGE made a $10 million cash contribution to the pension plan. No contributions were made in 2004. PGE does not expect to make a contribution to the pension plan in 2006. The measurement date for the pension plan is December 31.

Non-Qualified Benefit Plans - The Non-Qualified Benefit Plans in the accompanying table primarily represent obligations for a Supplemental Executive Retirement Plan (SERP). The SERP was closed to new participants in 1997. Investments in a non-qualified benefit plan trust (i.e. rabbi trust), consisting of trust owned life insurance policies (TOLI) and, beginning in 2003, marketable securities, are intended to be the primary source for financing these plans. Trust assets of $24 million as of December 31, 2005 and $22 million as of December 31, 2004 are shown in the accompanying table for informational purposes only and are not considered segregated and restricted as defined by SFAS No. 87, Employers' Accounting for Pensions. The investments in marketable securities, consisting of money market, bond, and equity mutual funds, are classified as trading and recorded at fair value. Unrealized gains in marketable securities were $1 million for each of the years 2005, 2004, and 2003. In addition, recognized gains on trust assets of $1 million for both 2005 and 2004 and $2 million for 2003 are included in net periodic benefit cost. The basis on which cost is determined in computing realized gains and losses on marketable securities is average cost. The measurement date for the non-qualified plans is December 31.

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

Other Benefits - PGE also participates in non-contributory post-retirement health and life insurance plans ("Other Benefits" in the table). Employees are covered under a Defined Dollar Medical Benefit Plan which limits PGE's obligation by establishing a maximum contribution per employee. Contributions made to a voluntary employees' beneficiary association (VEBA) 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 updated as appropriate. In 2005, PGE updated the mortality rate assumption used for the post-retirement benefits. The impact of this change on the benefit obligation was not significant.

In 2004, PGE established Health Retirement Accounts (HRAs) for its employees under which the Company agreed to make contributions to a trust to provide for claims by retirees for qualified medical costs. The 2004 bargaining unit agreement provides that retired employees may submit claims to the HRA for qualified medical expenses up to 58% of the value of any accumulated sick time at their retirement. The Company also granted a fixed dollar amount for all active non-bargaining employees which will become available for qualified medical expenses upon their retirement. As a result of the HRAs, the benefit obligation increased $6 million in 2004.

No contributions were made to the post-retirement plans in 2004. In 2005, PGE contributed $2 million to the HRAs. Contributions to the HRAs in 2006 are expected to be minimal. No contributions are expected to be made to the other post-retirement plans in 2006. The measurement date for the post-retirement plans and the HRAs 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 (in millions):

	Defined Benefit Pension Plan		Non-Qualified Benefit Plans		Other Benefits	
	2005	2004	2005	2004	2005	2004
Reconciliation of benefit obligation:						
Obligation at January 1	$ 450	$ 400	$ 22	$ 21	$ 55	$ 45
Service cost	12	12	-	-	1	1
Interest cost	25	24	1	2	3	3
Plan amendments	-	2	-	-	-	1
New plans	-	-	-	-	-	6
Assumed plans	-	-	2	-	-	-
Divestitures	(3)	-	-	-	-	-
Participants' contributions	-	-	-	-	1	1
Actuarial loss	18	29	1	1	2	2
Benefit payments	(19)	(17)	(2)	(2)	(3)	(4)
Obligation at December 31	$ 483	$ 450	$ 24	$ 22	$ 59	$ 55
Reconciliation of fair value of plan assets:						
Fair value of plan assets at January 1	$ 452	$ 415	$ 22	$ 22	$ 26	$ 26
Actual return on plan assets	29	54	2	2	1	3
Company contributions	10	-	-	-	2	-
Assumed plans	-	-	2	-	-	-
Participants' contributions	-	-	-	-	1	1
Divestitures	(3)	-	-	-	-	-
Benefit payments	(19)	(17)	(2)	(2)	(3)	(4)
Fair value of plan assets at December 31	$ 469	$ 452	$ 24	$ 22	$ 27	$ 26
Funded status:						
Funded (unfunded) status at December 31	$ (14)	$ 2	$ -	$ -	$ (32)	$ (29)
Unrecognized transition liability	-	-	-	-	2	2
Unrecognized prior service cost	5	6	-	1	7	8
Unrecognized loss	97	70	3	2	11	10
Prepaid pension cost (liability)	$ 88	$ 78	$ 3	$ 3	$ (12)	$ (9)
Accumulated benefit obligation	$ 426	$ 394	$ 21	$ 19	N/A	N/A
Amounts recognized in the Balance Sheet consist of:						
Prepaid benefit cost	$ 88	$ 78	$ 8	$ 9	$ (12)	$ (9)
Accumulated other comprehensive income	-	-	(5)	(6)	-	-
Net amount recognized	$ 88	$ 78	$ 3	$ 3	$ (12)	$ (9)
Assumptions:						
Discount rate used to calculate benefit obligation	5.75%	5.75%	5.75%	5.75%	5.50%	5.75%
Weighted average rate of increase in future compensation levels	4.43%	4.48%	N/A	N/A	5.30%	5.30%
Long-term rate of return on assets	9.00%	9.00%	N/A	N/A	8.62%	8.63%

	Defined Benefit Pension Plan			Non-Qualified Benefit Plans			Other Benefits		
	2005	2004	2003	2005	2004	2003	2005	2004	2003
Components of net periodic benefit cost:									
Service cost	$ 12	$ 12	$ 11	$ -	$ -	$ -	$ 1	$ 1	$ 1
Interest cost on benefit obligation	25	24	23	1	1	2	3	3	3
Expected return on plan assets	(41)	(40)	(39)	-	-	-	(2)	(2)	(1)
Amortization of transition asset	-	(2)	(2)	-	-	-	1	1	-
Amortization of prior service cost	2	2	1	1	1	-	1	-	-
Recognized (gain) loss	2	-	-	(1)	(1)	(2)	1	-	1
Net periodic benefit cost (income)	$ -	$ (4)	$ (6)	$ 1	$ 1	$ -	$ 5	$ 3	$ 4

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					
	2006	**2007**	**2008**	**2009**	**2010**	**2011 - 2015**
Pension Plan Payments (*)	$24	$24	$25	$25	$26	$159
Non-Qualified Plan Payments	2	2	2	1	1	10
Other Plan Payments	3	4	4	4	4	22
Total	$29	$30	$31	$30	$31	$191

(*) Increases in Pension Plan Payments from amounts estimated in prior years reflect updated mortality assumptions (discussed above) and increases in expected retirement rates.

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

For measurement purposes, a 9% annual rate of increase in the per capita cost of covered health care benefits is assumed for 2006. The rate is assumed to decrease to 5% by 2013 and remain at that level thereafter. Assumed health care cost trend rates can affect amounts reported for the health care plans. A one-percentage point change in assumed health care cost trend rates would have the following effects (in millions):

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

The asset allocation for the pension plan at December 31, 2005 and 2004 and the target allocation for 2006, by asset category, are as follows:

Asset Category	Percentage of Plan Assets December 31		Target Allocation
	2005	2004	2006
Equity Securities	67%	70%	67%
Debt Securities	33%	30%	33%
Total	100%	100%	100%

The asset allocation for the Non-Qualified Benefit Plans at December 31, 2005 and 2004 are as follows:

Asset Category	Percentage of Plan Assets December 31		Target Allocation
	2005	2004	2006
Cash Equivalents	10%	-	-
Debt Securities	7%	26%	10%
Equity Securities	37%	26%	52%
TOLI Policies	46%	48%	38%
Total	100%	100%	100%

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

The asset allocation for the Other Benefit Plans at December 31, 2005 and 2004, and the target allocation for 2006, by asset category, are as follows:

Asset Category	Percentage of Plan Assets December 31		Target Allocation
	2005	2004	2006
Equity Securities	68%	69%	68%
Debt Securities	32%	31%	32%
Total	100%	100%	100%

The Plans' investment policies call for permanent commitment to five asset classes to promote diversification at the plan level. The commitments to each class are controlled by an Asset Deployment Policy and Cash Management Policy that take profits from asset classes whose allocations have shifted above their target ranges to fund benefit payments and investments in asset classes whose allocations have shifted below their target ranges.

Other Non-Qualified Benefit Plans

In addition to the SERP Plan discussed above, PGE provides certain employees with benefits under an unfunded Management Deferred Compensation Plan (MDCP) whereby participants may defer a portion of their pay. Obligations for the MDCP were $54 million and $51 million at December 31, 2005 and 2004, respectively (not included in table). The costs of the SERP and MDCP Plans are excluded from prices charged to customers. Investments in trust owned life insurance policies and, beginning in 2003, marketable securities, are intended to be the primary source for financing the MDCP Plan. Total assets held in support of the MDCP Plan were $39 million at December 31, 2005 and $40 at December 31, 2004. Unrealized gains in marketable securities were $1 million for 2005 and 2004 and $2 million for 2003.

PGE sponsors additional non-qualified plans for certain employees and former directors. Obligations for these plans are minimal. Assets held in support of these plans totaled $2 million at December 31, 2005 and 2004.

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

401(k) Retirement Savings Plan

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

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

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

All contributions to the plan are invested in accordance with employees' individual investment choices. PGE made matching contributions to its employees' savings plan accounts of approximately $13 million in 2005, $12 million in 2004, and $10 million in 2003.

Note 3 - Income Taxes

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

	2005	2004	2003
Income Tax Expense			
Current:			
Federal	$88	$59	$59
State and local	8	8	7
	96	67	66
Deferred:			
Federal	(41)	(8)	(19)
State and local	(9)	(2)	-
	(50)	(10)	(19)
Investment tax credit adjustments	(3)	(3)	(3)
Total income tax expense before cumulative effect of a change in accounting principle	$43	$54	$44
Income tax expense allocated to:			
Operations	$46	$57	$50
Other income and deductions	(3)	(3)	(6)
Total income tax expense before cumulative effect of a change in accounting principle	$43	$54	$44
Effective Tax Rate Computation:			
Computed tax based on statutory federal income tax rate (35%) applied to income before income taxes	$37	$51	$35
Flow through depreciation	7	9	7
State and local taxes - net of federal tax benefit	1	5	4
Investment tax credits	(3)	(3)	(3)
Excess deferred taxes	(1)	(1)	(1)
Adjustments for previously-recorded taxes	2	(3)	-
Other	-	(4)	2
Total income tax expense before cumulative effect of a change in accounting principle	$43	$54	$44
Effective tax rate	39.9%	37.0%	44.0%

As of December 31, 2005 and 2004, the significant components of PGE's deferred income tax assets and liabilities were as follows (in millions):

	2005	2004
Deferred income tax assets		
Depreciation and amortization	$ 35	$ 37
Employee benefits	34	31
Allowance for uncollectible accounts	20	20
Land reclamation costs	3	3
Regulatory liabilities		
Asset retirement removal costs	139	113
Other	39	9
Other	17	22
Total deferred income tax assets	287	235
Deferred income tax liabilities		
Depreciation and amortization	463	465
Employee benefits	27	24
Property taxes	5	5
Price risk management	26	4
Regulatory assets		
Prior tax benefits recoverable	-	4
Debt reacquisition costs	8	9
Conservation investments	3	7
Energy efficiency programs	4	12
Power cost adjustment	-	7
Miscellaneous	11	13
Other	9	13
Total deferred income tax liabilities	556	563
Net deferred income taxes	$ 269	$ 328
Classification of net deferred income taxes		
Included in current liabilities	$ 51	$ 15
Included in non current liabilities	218	313
Net deferred income taxes	$ 269	$ 328

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

Note 4 - Common and Preferred Stock

(Dollars in Millions)	Common Stock Number of Shares	$3.75 Par Value	Limited Voting Junior Preferred Number of Shares	$1.00 Par Value	Paid-in Capital
December 31, 2003	42,758,877	$160	1	-	$481
December 31, 2004	42,758,877	160	1	-	481
December 31, 2005	42,758,877	160	1	-	482

Limited Voting Junior Preferred Stock

On September 30, 2002, following approval by the Bankruptcy Court, Debtor-in-Possession lenders, the OPUC, and PGE's Board of Directors, a single share of $1.00 par value Limited Voting Junior Preferred Stock (Junior Preferred) was issued by PGE to an independent party. The Junior Preferred has no dividend, a liquidation preference to the Common Stock as to par value but junior to existing preferred stock, and certain restrictions on transfer. It also has voting rights, which limit, subject to certain exceptions, PGE's right to commence any voluntary bankruptcy, liquidation, receivership, or similar proceedings (Bankruptcy) without the consent of the holder of the share of Junior Preferred, and may be redeemed for its par value at any time after PGE is no longer under the control (as defined) of any person or entity, or of any affiliate of such person or entity that is subject to an order for relief under the United States Bankruptcy Code or any successor statute. On March 14, 2006, PGE's Board of Directors authorized the Junior Preferred stock to be redeemed on March 28, 2006. Upon redemption, the Junior Preferred will be cancelled and will not be reissued.

Common Stock Dividends

Enron owns all of the issued and outstanding common stock of PGE. Under Oregon law and specific OPUC merger conditions, Enron's access to PGE cash or assets (through dividends or otherwise) is limited. PGE is restricted from paying dividends or making other distributions to Enron without prior OPUC approval to the extent that such payment or distribution would reduce PGE's common equity capital below 48% of its total capitalization (excluding short-term borrowings). Management believes that, at December 31, 2005, the Company has the ability to pay dividends, notwithstanding this restriction.

The OPUC order approving the issuance of new PGE common stock (see "Common Stock Issuance" below) includes a stipulation containing several conditions, including a requirement that, after issuance of the new stock, PGE cannot pay a dividend that would cause the common equity capital percentage to fall below 48% (plus $40 million) without Commission approval. PGE has agreed to maintain the additional $40 million of common equity pending the outcome of its next general rate case to assure the Company's financial capacity to absorb any adjustment(s) in its revenue requirement related to its ownership by Enron. The requirement is reduced to 45% when the Disputed Claims Reserve (DCR) holds between 20% and 40% of the issued and outstanding common stock of PGE, with no minimum common equity capital percentage requirement when the DCR holds less than 20% of the issued and outstanding common stock of PGE. Other conditions include a requirement that the OPUC be notified (simultaneously with the public) of any dividend declared by PGE's Board of Directors and that, before the issuance of new common stock, PGE cannot make a dividend distribution to Enron unless PGE has a rating on its senior secured debt of not lower than BBB+ from Standard & Poor's.

Common Stock Issuance

In accordance with the Chapter 11 Plan, Enron plans to distribute new PGE common stock to the Debtors' creditors holding allowed claims. Current PGE common stock held by Enron will be cancelled and 62,500,000 shares (of 80,000,000 shares authorized) of new PGE common stock without par value will be distributed over time to Debtors' creditors holding allowed claims. Initially, at least 30 percent of the new PGE common stock will be issued by PGE to the Debtors' creditors that hold allowed claims, with the remainder issued to a Disputed Claims Reserve (DCR) where it will be held to be released over time to the Debtors' creditors holding allowed claims in accordance with the Chapter 11 Plan.

At the time the new common stock issuance takes place, currently expected on or about April 3, 2006, PGE's balance sheet will be adjusted to reflect the combined book values of the current $3.75 par value common stock and Other paid-in capital into the new item "Common stock, no par value". Costs incurred for the issuance of new common stock, and to become a publicly-traded company, are charged to operating expense as incurred.

Note 5 - Credit Facility and Debt

At December 31, 2005, PGE had a $400 million five-year unsecured revolving credit facility with a group of commercial banks. The facility, which expires in 2010, replaced the Company's $50 million 364-day revolving credit facility, which expired in May 2005, and a $100 million three-year facility. It is available for general corporate purposes, with the maximum amount available to PGE for borrowings and/or the issuance of standby letters of credit. At December 31, 2005, PGE had utilized approximately $17 million in 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 such date may be extended for an additional year for those lenders who agree to an extension. The facility requires annual fees based on PGE's unsecured credit rating, and contains customary covenants and default provisions, including a requirement that limits consolidated indebtedness, as defined in the facility, to 65% of total capitalization. At December 31, 2005, PGE was in compliance with this covenant.

PGE management believes that its existing line of credit and cash from operations provide the Company with sufficient liquidity to meet its day-to-day cash requirements. As of December 31, 2005, the Company has sufficient capacity under its Indenture of Mortgage to issue additional First Mortgage Bonds in amounts sufficient to meet its anticipated capital requirements and to supplement day-to-day cash requirements to the extent necessary.

PGE had no short-term borrowings in 2004 or 2005.

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

Schedule of Long-Term Debt at December 31:	2005	2004
	(In Millions)	
First Mortgage Bonds		
Maturing 2005 - (9.07%)	$ -	$ 18
Maturing 2007 - (7.15%)	50	50
Maturing 2010 - (8 1/8%)	150	150
Maturing 2012 - (5.6675%)	100	100
Maturing 2013 - (5.279% - 5.625%)	100	100
Maturing 2021 - 2033 (6.75% - 9.31%)	120	120
	520	538
Pollution Control Bonds		
Port of Morrow, Oregon, variable rate, due 2033 (5.20% fixed rate to 2009)	23	23
City of Forsyth, Montana, variable rate, due 2033 (5.20% - 5.45% fixed rate to 2009)	119	119
Port of St. Helens, Oregon, 4.80% due 2010	37	37
Port of St. Helens, Oregon, due 2014 (5.25% - 7.13% fixed rate)	15	15
	194	194
Other		
6.91% Conservation Bonds maturing monthly to 2006 (a)	9	20
7.875% Notes due March 15, 2010	149	149
7.75% Series Cumulative Preferred Stock (a) (b)	19	22
Unamortized debt discount	(1)	(1)
	176	190
	890	922
Long-term debt due within one year (a)	(11)	(30)
Total long-term debt	$ 879	$ 892

(a) Due within one year; consists of $9 million of Conservation Bonds, and $2 million of 7.75% Series Cumulative Preferred Stock.

(b) The 7.75% Series Cumulative Preferred Stock (no par value), which is mandatorily redeemable, is classified as long-term debt in accordance with SFAS No. 150. The preferred stock series is redeemable by operation of a sinking fund that requires the annual redemption of 15,000 shares at $100 per share beginning in 2002, with all remaining shares to be redeemed by sinking fund in 2007. At its option, PGE may redeem, through the sinking fund, an additional 15,000 shares each year. Open market share purchases can be applied towards the annual redemption requirement. In 2005, PGE redeemed 30,000 shares, consisting of 15,000 shares for the annual sinking fund requirement and 15,000 additional shares acquired at its option. At December 31, 2005, there were 189,727 shares outstanding.

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

	2006	2007	2008	2009	2010	Thereafter	Total
Debt Maturities	$11	$67	$ -	$ -	$335	$477	$890

Note 6 - 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 - The carrying amount of cash and cash equivalents approximates fair value because of the short maturity of those instruments.

Other investments - The carrying amounts of other investments approximate fair value. These include the Nuclear decommissioning trust, Non-qualified benefit plan trust, and other miscellaneous financial instruments.

Long-term debt - The fair value of long-term debt is estimated based on the quoted market prices for the same or similar issues or on the current rates offered to PGE for debt of similar remaining maturities. The estimated fair values of debt instruments are as follows (in millions):

	2005		**2004**	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt including current maturities	$890	$ 950	$922	$1,005

Note 7 - Commitments and Guarantee

Natural Gas Agreements

PGE has entered into agreements for the purchase and transportation of natural gas from domestic and Canadian sources for its natural gas-fired generating facilities. The Company has also entered into a ten-year natural gas storage agreement, effective May 1, 2007, for the purpose of fueling the Company's Port Westward and Beaver generating plants located adjacent to the storage facility. As of December 31, 2005, these agreements require net payments of approximately $35 million in 2006, $17 million in both 2007 and 2008, $15 million in 2009, $13 million in 2010, and $41 million over the remaining years of the contracts, which expire at varying dates from 2006 to 2017.

Purchase Commitments

Certain commitments have been made for capital and other purchases for 2006 and beyond. Such commitments total $404 million as of December 31, 2005, reflecting future payment requirements of $192 million in 2006, $43 million in 2007, and $54 million in 2008, $33 million in 2009, $10 million in 2010, and $72 million over the remaining years of the commitments. Such commitments include those related to construction of Port Westward, Trojan decommissioning activities, hydro license agreements, information systems, upgrades to production and distribution facilities, and system maintenance work. Termination of these agreements could result in cancellation charges.

Coal and Transportation Agreements

PGE has coal and related rail transportation agreements with take-or-pay provisions of approximately $13 million annually in 2006 and 2007, and $14 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, 2005	$381	$210	$291	$232	$ 22
PGE's current share of:					
Output	12.0%	7.5%	18.7%	19.4%	100%
Net capability (megawatts)	136	56	133	131	36
PGE's annual cost, including debt service:					
2005	$ 8	$ 4	$ 7	$ 6	$ 5
2004	8	4	6	6	5
2003	9	4	7	7	5
Contract expiration date	2011	*	2009	2018	2017

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

PGE's share of debt service costs, excluding interest, is approximately $7 million annually in 2006 and 2007, $8 million annually in 2008 and 2009, and $7 million in 2010. Total minimum payments through the remainder of the contracts are estimated at $51 million.

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

In November 2004, Douglas County PUD (Douglas), owner of the Wells Hydroelectric Project (Project), entered into a settlement with the Colville Confederated Tribes (Colville Tribe) that resolved claims for charges for the use of Colville tribal lands. The settlement, which was approved by the FERC in February 2005, impacted the quantity and price of PGE's share of the output of the Project. The settlement required that Douglas pay a $13.5 million lump sum, convey certain real property, and allocate (at cost) 4.5% of Project's output to the Colville Tribe; such allocation increases to 5.5% for all years after 2018. To fund the $13.5 million payment, PGE and other purchasers of the Project's output entered into a Settlement Endorsement Agreement (Agreement) providing for the sale by Douglas of revenue bonds. The Agreement requires that each purchaser of the Project's output pay their respective share of debt service on the revenue bonds, with PGE's annual share calculated at approximately $350,000. In addition to its share of debt service payments, PGE's share of the Project's output was reduced from 20.3% to 19.4% beginning in April 2005. The effects of both the debt service requirement and the reduction in output were included in projected power costs in PGE's final 2005 and 2006 RVM filings approved by the OPUC.

As of December 31, 2005, PGE has power purchase contracts with other counterparties, requiring payments of approximately $706 million in 2006, $304 million in 2007, $90 million in both 2008 and 2009, $91 million in 2010, and $645 million over the remaining years of the contracts, which expire at varying dates from 2011 to 2035. As of December 31, 2005, PGE has power sale contracts with other counterparties of approximately $230 million in 2006, $70 million in 2007, $14 million in 2008, $12 million in 2009, $11 million in 2010, and $16 million over the remaining years of the contracts, which expire at varying dates from 2011 to 2012. PGE also has power capacity contracts as of December 31, 2005 that require payments of approximately $24 million annually from 2006 through 2010 and are expected to average approximately $20 million from 2011 through 2016.

PGE has two long-term power exchange contracts. One exchange contract is with a summer-peaking California utility to help meet the Company's winter-peaking power requirements. There was no outstanding exchange balance under this contract at December 31, 2005. The other exchange contract is with a winter-peaking Northwest utility to help meet the Company's summer-peaking power requirements. At December 31, 2005, PGE owed 8,667 MWhs of electricity, all of which was delivered by the end of February 2006.

Leases

PGE has an operating lease for its headquarters complex located in Portland, Oregon. In May 2005, PGE purchased the coal-handling facility at Boardman, which the Company had previously leased. Lease payments charged to expense totaled $8 million in 2005 and $10 million in both 2004 and 2003.

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

Year Ending December 31	Operating Leases (Net of Sublease Rentals)
2006	$ 7
2007	7
2008	7
2009	7
2010	7
Remainder	181
Total	$216

Included in the above table is approximately $126 million for PGE's headquarters complex reflecting the base lease period through 2018 and renewal period options through 2043.

Guarantee

PGE entered into a sale transaction in 1985 in which it sold an undivided 15% interest in its Boardman coal plant (Plant) 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 the Plant and the Intertie (P&T Agreements) to a regulated electric utility (Utility) unrelated to PGE, the Purchaser, or the Lessee. The payments by the Utility under the P&T Agreements exceed the payments to be made by the Lessee to the Purchaser under the lease. In exchange for PGE undertaking certain obligations of the Lessee under the lease, the Lessee reassigned to PGE certain rights, including the excess payments, under the P&T Agreements. However, in the event that the Utility defaults on the payments it owes under the P&T Agreements, PGE may be required to pay the damages owed by the Lessee to the lessor under the lease. Assuming no recovery from the Utility and no reduction in damages from mitigating sales or leases related to the Boardman Assets and P&T Agreements, the maximum amount that would be owed by PGE in 2006 is approximately $205 million. Management believes that circumstances that could result in such amount, or any lesser amount, being owed by the Company are remote.

Note 8 - Price Risk Management

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

Changes in the fair value of retail (non-trading) derivative instruments prior to settlement that do not qualify for either the normal purchase and normal sale exception or for hedge accounting are recorded on a net basis in Purchased Power and Fuel expense. As derivative instruments are settled, sales are recorded in Operating Revenues, with purchases, natural gas swaps and futures recorded in Purchased Power and Fuel expense. PGE records the non-physical settlement of non-trading electricity derivative activities on a net basis in Purchased Power and Fuel expense, in accordance with EITF 03-11.

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

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

Non-Trading Activities

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

SFAS No. 133 requires unrealized gains and losses on derivative instruments that do not qualify for either the normal purchase and normal sale exception or hedge accounting to be recorded in earnings in the current period. Rates approved by the OPUC are based on a valuation of all the Company's energy resources, including derivative instruments existing on October 27, 2005 that will settle during the 12-month period from January 1, 2006 to December 31, 2006. Such valuation was based on forward price curves in effect on November 8, 2005 for electricity and natural gas. The timing difference between the recognition of gains and losses on certain derivative instruments and their realization and subsequent recovery in rates is recorded as a regulatory asset or regulatory liability to reflect the effects of regulation under SFAS No. 71. As these contracts are settled, the regulatory asset or regulatory liability is reversed. However, as there is currently no power cost adjustment mechanism in effect for 2006, unrealized gains and losses related to new derivatives not included in rates that will settle in 2006, and changes in fair value of financial derivatives used to set rates, are not deferred as regulatory assets or regulatory liabilities.

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

Non-Trading Activities	2005	2004	2003
Net unrealized gains	$ 41	$ 6	$ 29
SFAS No. 71 regulatory (liability) asset	(37)	(22)	(16)
Net unrealized gains (losses)	$ 4	$ (16)	$ 13

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

Derivative Activities Recorded in OCI	2005	2004	2003
Other unrealized holding net gains arising during the period	$ 46	$ 20	$ 14
Reclassification adjustment for contract settlements included in net income	7	(10)	(4)
Reclassification adjustment in net income due discontinuance of cash flow hedges (*)	(2)	-	(15)
Reclassification of unrealized (gains) losses to SFAS No. 71 regulatory (liability) asset	(48)	(16)	4
Total - Unrealized gains (losses) on derivatives classified as cash flow hedges	$ 3	$ (6)	$ (1)

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

Hedge ineffectiveness from cash flow hedges was not material in 2005, 2004, and 2003. As of December 31, 2005, the maximum length of time over which PGE is hedging its exposure to such transactions is approximately 69 months. The Company estimates that of the $65 million of net unrealized gains in OCI at December 31, 2005, $55 million will be reclassified into earnings within the next twelve months (offset by a $55 million SFAS No. 71 regulatory liability), and $10 million will be reclassified over the remaining 57 months (fully offset by a SFAS No. 71 regulatory liability).

Trading Activities

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

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

	2005	2004	2003
Trading Activities (In Millions)			
Unrealized Gain (Loss)	$ (1)	$ 1	$ 1
Realized Gain	1	-	1
Net Gain in Operating Revenues	$ -	$ 1	$ 2
Electricity Trading - MWhs (thousands)			
Sales	815	9,699	13,551
Purchases	815	9,699	13,551

Note 9 - Jointly Owned Plant

At December 31, 2005, PGE had the following investments in jointly owned generating plants (dollars in millions):

			PGE Interest			
Facility	**Location**	**Fuel**	**Percent**	**MW Capacity**	**Plant In Service**	**Accumulated Depreciation (*)**
Boardman	Boardman, OR	Coal	65.00	380	$417	$250
Colstrip 3 and 4	Colstrip, MT	Coal	20.00	296	469	288
Pelton/Round Butte	Madras, OR	Hydro	66.67	298	113	41

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

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

Note 10 - Legal and Environmental Matters

Legal Matters

Trojan Investment Recovery - In 1993, following the closure of the Trojan Nuclear Plant, 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. The filing was a result of PGE's decision earlier in the year to cease commercial operation of Trojan as a part of its least cost planning process. In 1995, the OPUC issued a general rate order (1995 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 requested reviews were subsequently filed in the Marion County, Oregon 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 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 and the OPUC requested the Oregon Supreme Court to conduct a review of the Court of Appeals decision on the return on investment issue. In addition, URP requested the Oregon Supreme Court to review the Court of Appeals decision on the return of investment issue. PGE requested the Oregon Supreme Court to suspend its review of the 1998 Court of Appeals opinion pending resolution of URP's complaint with the OPUC challenging the accounting and ratemaking elements of the settlement agreements approved by the OPUC in September 2000 (discussed below). On November 19, 2002, the Oregon Supreme Court dismissed PGE's and URP's petitions for review of the 1998 Oregon Court of Appeals decision. As a result, the 1998 Oregon Court of Appeals opinion stands and the case has been remanded to the OPUC.

While the petitions for review of the 1998 Court of Appeals decision were pending at the Oregon Supreme Court, in 2000, PGE, CUB, and the staff of the OPUC entered into agreements to settle the litigation related to PGE's recovery of, and return on, its investment in the Trojan plant. 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 PGC's 1997 merger with Enron. The settlement also allows 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 is being recovered from PGE customers, with no return on the unamortized balance, over an approximate five-year period that began in October 2000. At December 31, 2005, the remaining balance to be collected was approximately $1 million. After offsetting the investment in Trojan with these credits and prior tax benefits, the remaining Trojan regulatory asset balance of approximately $5 million (after tax) was expensed. As a result of the settlement, PGE's investment in Trojan is no longer included in rates charged to customers, either through a return of or a return on that investment. Authorized collection of Trojan decommissioning costs is unaffected by the settlement agreements or the OPUC orders.

The URP filed a complaint with the OPUC challenging the settlement agreements and the Commission's September 2000 order. In March 2002, after a full contested case hearing, 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, Oregon Circuit Court. On November 7, 2003, the Marion County Circuit Court issued an opinion remanding the case to the OPUC for action to reduce rates or order refunds. The opinion does not specify the amount or timeframe of any reductions or refunds. PGE and the OPUC have filed appeals to the Oregon Court of Appeals.

In a separate legal proceeding, two class action suits were filed in Marion County Circuit Court against PGE on January 17, 2003 on behalf of two classes of electric service customers. One case seeks to represent current PGE customers that were customers during the period from April 1, 1995 to October 1, 2000 (Current Class) and the other case seeks to represent PGE customers that were customers during the period from April 1, 1995 to October 1, 2000, but who are no longer customers (Former Class). The suits seek damages of $190 million for the Current Class and $70 million for the Former Class, as a result of the inclusion of a return on investment of Trojan in the rates PGE charges its customers. On 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 Plaintiff's claims. On December 14, 2004, the Judge granted the Plaintiff's motion for Class Certification and Partial Summary Judgment and denied PGE's motion for Summary Judgment. PGE filed a proposed order certifying the issue for an interlocutory appeal. An order rejecting the proposed order was entered on February 1, 2005. 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 May 3, 2005, the Oregon Supreme Court granted both Petitions. Briefing and oral arguments have been completed and a decision is pending.

On March 3, 2004, the OPUC re-opened three dockets in which it had addressed the issue of a return on PGE's investment in Trojan, including the 1995 Order and 2002 Order related to the settlement of 2000.

On August 31, 2004, the administrative law judge issued an Order (Scoping Order) defining the scope of the proceedings necessary to comply with the Marion County Circuit Court orders remanding this matter to the OPUC. On October 18, 2004, the OPUC affirmed the Scoping Order. On December 20, 2004, the URP and Class Action Plaintiffs filed an application with the OPUC for reconsideration of the Scoping Order. On February 11, 2005, the OPUC denied reconsideration. On April 18, 2005, URP and Linda K. Williams filed a complaint against the OPUC in Marion County Circuit Court challenging the OPUC's affirmation of the Scoping Order. The OPUC filed a motion to dismiss the complaint, and on September 21, 2005, the Marion County Circuit Court granted the OPUC's motion. Hearings in the first phase of the OPUC proceeding have been held and a decision is pending.

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

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

Multnomah County Business Income Taxes - In January 2005, David Kafoury and Kafoury Brothers, LLC filed a class action lawsuit in Multnomah County Circuit Court against PGE on behalf of all PGE customers who were billed on their electric bills and paid amounts for Multnomah County Business Income Taxes (MCBIT) after 1996. The plaintiffs alleged that during the period 1997 through the third quarter 2004, PGE collected in excess of $6 million from its customers for MCBIT that was never paid to Multnomah County. The charges were billed and collected under OPUC rules that allow utilities to collect taxes imposed by the county. As a member of Enron's consolidated income tax return, PGE paid the tax it collected to Enron. The plaintiffs sought judgment against PGE for restitution of MCBIT collected from customers plus interest, recoverable costs, and reasonable attorney fees. The plaintiffs filed an amended complaint on February 25, 2005, adding claims for fraud, unjust enrichment, conversion, statutory violations, and seeking punitive damages.

On May 23, 2005, the Court granted PGE's motion for a stay for all purposes until the OPUC's issuance of a declaratory ruling in response to questions by PGE as to whether OPUC rules authorized PGE collections of the MCBIT and whether any refunds to customers were controlled by an OPUC three-year limitation for billing adjustments. On October 5, 2005, the OPUC issued an order that determined that Commission rules authorized PGE collections of the MCBIT from Multnomah County customers but did not require that PGE calculate them in any particular way. Because the OPUC did not find that PGE had violated its rule, the Commission did not answer whether its three-year limitation on billing adjustments applied.

On December 28, 2005, the parties agreed to a settlement by which PGE will make refunds and payments totaling $10 million, inclusive of interest and plaintiffs' attorney fees, costs, and expenses as approved by the Court's final order. The settlement includes no admission of liability or wrongdoing by PGE. Distribution to customers is limited to amounts collected during the period 1999 through 2005. PGE established a reserve of $10 million in 2005 related to the settlement. The settlement is subject to final approval by the Multnomah County Circuit Court following a hearing currently scheduled for late July 2006.

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

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

On December 27, 2005, the OPUC issued a Joint Ruling to hold the Complaint and Deferred Accounting application in abeyance pending rehearing of an order previously issued by the OPUC in a rate proceeding involving another Oregon electric utility. Management cannot predict the ultimate outcome of these matters or estimate any potential loss.

Union Grievances - In November 2001, grievances were filed by several members of the International Brotherhood of Electrical Workers Local 125 (IBEW), the bargaining unit representing PGE's union workers, alleging that losses in their pension/savings plan were caused by Enron's manipulation of its stock. The grievances, which do not specify an amount of claim, seek binding arbitration. PGE filed for relief in Multnomah County Circuit Court seeking a ruling that the grievances are not subject to arbitration. On August 14, 2003, the Court granted PGE's motion for summary judgment, finding that the grievances are not subject to arbitration. A final judgment was entered on October 6, 2003. On October 22, 2003, the IBEW appealed the decision to the Oregon Court of Appeals. Both the U.S. District Court and the Bankruptcy Court approved the settlement of the class action litigation styled In re Enron Corp. Securities Derivative & "ERISA" Litigation, Pamela M. Tittle, et al, v. Enron Corp., et al, Civil Action No. H-01-3913, U.S. District Court for the Southern District of Texas, Houston Division (Tittle Action). On September 13, 2005, the U.S. District Court entered a Bar Order in the Tittle Action, which specifically bars all claims arising out of this case, including the IBEW grievance proceeding. On October 18, 2005, at the request of the Oregon Court of Appeals, PGE filed a response memorandum in which PGE argued that the Bar Order makes the grievance moot. A decision is pending. Management cannot predict the ultimate outcome of this matter or estimate any potential loss.

Environmental Matters

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

Also in 2000, PGE agreed with the Oregon Department of Environmental Quality (DEQ) to perform a voluntary remedial investigation of its Harborton Substation site to confirm whether any hazardous substances had been released from the substation property into the Portland Harbor sediments. In February 2002, PGE submitted its final investigative report to the DEQ, indicating that the voluntary investigation demonstrated that there is no likely present or past source or pathway for release of hazardous substances to surface water or sediments in the Portland Harbor Superfund Site at or from the Harborton Substation site. Further, the voluntary investigation demonstrated 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 final investigative report to the EPA and, in a May 18, 2004 letter, the EPA stated that "based on the summary information provided by DEQ and the limited data EPA has at this stage in its process, EPA agrees at this time, that this site does not appear to be a current source of contamination to the river." Management believes that the Company's contribution to the sediment contamination, if any, from the Harborton Substation site would qualify it as a de minimis PRP.

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

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

In 1974 and 1979, major oil spills occurred at the Harbor Oil site that impacted an approximate two acre area. Elevated levels of contaminants, including metals, pesticides, and polychlorinated biphenyl's (PCBs), have been detected at the site. On September 29, 2003, following investigation and site assessment by the EPA, Harbor Oil was included on the federal National Priority List as a federal Superfund site.

PGE received a Special Notice Letter for Remedial Investigation/Feasibility Study from the EPA, dated June 27, 2005, in which the Company was named as one of fourteen PRPs with respect to the Harbor Oil site. The letter starts a period for PRPs to participate in negotiations with the EPA to reach a settlement to conduct or finance a Remedial Investigation and Feasibility Study of the Harbor Oil site. Discussions among the EPA and the PRPs, including PGE, have commenced.

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

Other - In October 2003, PGE agreed with the DEQ to provide cost recovery for oversight of a voluntary investigation and/or potential cleanup of petroleum products at another Company site that is upland from the Portland Harbor Superfund Site. The site investigation has been completed and a report was submitted to the DEQ in August 2005. The report concludes that fuel and related contaminants have not migrated to the Willamette River from the site. The DEQ has stated that it is satisfied with the report. PGE management considers any material liability related to this matter to be remote.

Note 11 - Asset Retirement Obligations

SFAS No. 143, Accounting for Asset Retirement Obligations (ARO), which was adopted on January 1, 2003, 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. 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, amounts are included in Depreciation and Amortization expense for Utility plant and Other Income (Deductions) for Other property.

FASB Interpretation No. 47 (FIN 47), Accounting for Conditional Asset Retirement Obligations - an interpretation of FASB Statement No. 143, was adopted on December 31, 2005. FIN 47 clarifies that the term "conditional asset retirement obligation," as used in SFAS No. 143, refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. An entity is required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated, even though uncertainty exists about the timing and/or method of settlement.

Regulation - Pursuant to regulation, AROs of rate-regulated long-lived assets are included in depreciation expense allowed in rates charged to customers. Any differences in the timing of recognition of costs for financial reporting and ratemaking purposes are deferred as a regulatory asset or regulatory liability under SFAS No. 71. PGE expects any changes in estimated AROs to be incorporated in future rates. Substantially all significant AROs are included in rate regulation.

Asset Retirement Obligations

SFAS 143 - Upon adoption of SFAS No. 143 at January 1, 2003, PGE recorded AROs of $15 million for utility plant and $9 million for other property and adjusted the ARO for the Trojan Plant to $121 million. The ARO associated with decommissioning of the Trojan plant was recorded on a nominal dollar basis at the time of the plant's abandonment in 1993, with costs to be recovered through regulation recorded as a regulatory asset. Upon the adoption of SFAS No. 143, the regulatory asset and the related ARO for decommissioning of the Trojan plant were reduced by $55 million to adjust the balances to an estimated fair value as required by SFAS No. 143.

The $11 million transition adjustment for rate-regulated utility plant, consisting of the Boardman and Colstrip Units 3 and 4 coal plants, the Beaver and Coyote Springs gas turbine plants, and the Bull Run hydro project, was deferred as a regulatory liability pursuant to SFAS No. 71. In addition, PGE recorded a $4 million after-tax gain in earnings from the cumulative effect of a change in accounting principle related to other property. This transition adjustment represents a difference in using a straight-line amortization vs. accretion methodology under SFAS No. 143.

FIN 47 - A $2 million transition adjustment was recorded as of December 31, 2005 for rate-regulated utility plant resulting from the application of FIN 47, consisting of conditional asset retirement obligations for pole disposal, mercury vapor light disposal, asbestos remediation, PCB disposal, underground storage tank removal, and other miscellaneous disposal costs. The transition adjustment represents a difference in using a straight-line amortization vs. accretion methodology under SFAS No. 143. The $2 million transition adjustment was fully offset by adjustments to regulatory liabilities pursuant to SFAS No. 71.

The following presents the effects to the balances and activities in AROs for the years indicated (in millions):

	For Year Ended December 31,		
	2005	2004	2003
Beginning Balance	$ 120	$ 129	$ 145
Activity			
AROs incurred	2	-	-
Expenditures	(4)	(17)	(21)
Accretion	6	6	6
Revisions	10	2	(1)
Ending Balance	$ 134	$ 120	$ 129

Unrecognized Asset Retirement Obligations

PGE has certain tangible long-lived assets for which AROs are not measurable. An ARO will be required to be recorded when circumstances change. The 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 12 - 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. Since plant closure, PGE has committed itself to a safe and economical transition toward a decommissioned plant. In May 2005, following completion of radiological decommissioning and approval of the NRC, the plant's operating license was terminated. 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 permanent off-site storage is available.

Decommissioning - The Trojan decommissioning plan includes an estimate of PGE's cost to decommission the plant. The original cost estimate, which was based upon a site-specific engineering study, is periodically updated by PGE. In 2005, previous cost estimates were revised to reflect changes in the timing of decommissioning activities, due primarily to a delay in the completion of a permanent spent fuel storage facility and acceleration of the demolition of major plant structures. At December 31, 2005, the asset retirement obligation, measured at estimated fair value in accordance with SFAS No. 143, is $107 million. (See Note 11, Asset Retirement Obligations, for further information).

ASSET RETIREMENT OBLIGATION (ARO)
(In Millions)

Balance, 12/31/04	$	96
2005 Expenditures		(4)
2005 Accretion		5
2005 Estimate Revisions		10
Balance, 12/31/05	$	107
Total expenditures through 12/31/05	$	210

Remaining decommissioning activities consist of demolition of the existing structures, operation of the ISFSI to the year 2023, and decommissioning of the ISFSI. Final site restoration activities are anticipated to begin in 2023 after PGE completes shipment of spent fuel to a United States Department of Energy (USDOE) facility (see "Nuclear Fuel Disposal and Cleanup of Federal Plants" below).

DECOMMISSIONING TRUST ACTIVITY
(In Millions)

		2005		2004
Beginning Balance	$	22	$	35
Activity				
Contributions		14		14
Earnings		1		1
Disbursements		(6)		(28)
Ending Balance	$	31	$	22

PGE's current retail prices include recovery of $14 million annually through 2011 for decommissioning costs; an equal amount is recorded in amortization expense. These amounts are deposited in a trust fund, which is limited to reimbursing PGE for activities covered in Trojan's decommissioning plan. Funds are withdrawn as required to cover general decommissioning costs and operation of the ISFSI.

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

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

In 2002, the USDOE formally recommended Yucca Mountain, Nevada as the nation's first long-term geologic (underground) repository for high-level radioactive waste produced in the United States. The proposed location is based on the conclusions of scientific studies of the site, conducted over 20 years, which support a finding of suitability, as mandated by the Nuclear Waste Policy Act and various regulations of the NRC, USDOE, and the EPA. The House and Senate approved the site and in 2002, President Bush signed the Yucca Mountain resolution into law. Lawsuits have been filed objecting to the recommendation of Yucca Mountain as a nuclear waste repository. Based upon updated information received from the USDOE regarding the acceptance of spent nuclear fuel from Trojan, PGE has extended its projection for the final shipment of spent fuel from 2018 to 2023. The USDOE has not yet submitted to the NRC the required application for an operating license for the repository. Further delays may make it difficult for PGE to move its spent nuclear fuel, currently contained in the ISFSI, to permanent underground storage by 2023.

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

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

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

Nuclear Insurance - The Price-Anderson Amendment of 1988 limits public liability claims that could arise from a nuclear incident and also provides for loss sharing among all owners of nuclear reactor licenses. Because Trojan has been permanently de-fueled, PGE has been exempted by the NRC from participation in the secondary financial protection pool covering losses in excess of $300 million at other nuclear plants. The NRC has also reduced the required primary nuclear insurance coverage for Trojan to $100 million and has allowed PGE to self-insure for on-site decontamination related to spent nuclear fuel stored in the ISFSI. PGE continues to insure non-contamination property, in the amount of $25 million, under the Company's "All Risk" property insurance on the Trojan plant.

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

Note 13 - Related Party Transactions

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

	December 31, 2005	December 31, 2004
Receivables from affiliated companies		
Enron Subsidiaries:		
Portland General Holdings, Inc.		
Accounts Receivable[a]	$ -	$ 5
Allowance for Uncollectible Accounts [a]	-	(1)
PGH II and its subsidiary		
Accounts Receivable[a]	-	1
Allowance for Uncollectible Accounts[a]	-	(1)
Payables to affiliated companies		
Enron Corp:		
Accounts Payable[b]	4	4
Income Taxes Payable[c]	25	21

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

For the Years Ended December 31	2005	2004	2003
Expenses billed from affiliated companies			
Enron Corp:			
Intercompany services[a]	$ 7	$ 28	$ 34
Expenses billed to affiliated companies			
PGH II and its subsidiaries:			
Intercompany services[a]	-	1	1
Interest, net from affiliated companies			
Enron Corp:			
Interest expense[b]	-	-	(8)

[a] Included in Administrative and other on the Consolidated Statements of Income
[b] Included in Other Income (Deductions) on the Consolidated Statements of Income

Income Taxes Payable - As a member of Enron's consolidated income tax return, PGE made payments to Enron for the Company's income tax liabilities. The $25 million income taxes payable to Enron at December 31, 2005 represents a net current income taxes payable for the fourth quarter of 2005 that was paid to Enron in January 2006. During 2005, PGE paid $85 million to Enron for income taxes payable, consisting of $21 million outstanding at December 31, 2004 related to the fourth quarter of 2004 and $64 million for the first nine months of 2005.

Intercompany Receivables and Payable - As part of its continuing operations, PGE bills affiliates for various services provided by the Company. These include services provided by PGE employees, as well as other corporate services. In addition, Enron passes through PGE's share of costs related to certain insurance coverage. Transactions with affiliates are subject either to approval of, or confirmation filing requirements with, the OPUC. Under OPUC regulations, services provided to affiliates by PGE are charged at the higher of cost or market, while affiliated services received by PGE are charged at the lower of cost or market.

Affiliate transactions were also regulated by the SEC until February 8, 2006, when PUHCA 1935 was repealed by the Energy Policy Act of 2005 and replaced with the PUHCA 2005. Certain transactions are now regulated by the FERC, which obtains access to holding company books and records and may determine cost allocations in certain affiliate transactions. PGE does not expect that PUHCA 2005 will have a material impact on the Company's operations or financial results.

Enron - Beginning January 1, 2005, administration of the medical/dental benefit and retirement savings plans was returned to PGE from Enron; as a result, Enron no longer passes through costs to PGE for these services. In 2005, Enron billed PGE approximately $7 million for insurance coverage and costs related to the resolution of certain employee benefit plan matters (see below). In 2004, Enron billed PGE approximately $28 million, consisting of $25 million for medical/dental benefits and retirement savings plan matching and $3 million for insurance coverage. In 2003, Enron billed PGE approximately $34 million, consisting of $20 million for medical/dental benefits and retirement savings plan matching, $1 million for insurance coverage, and $13 million for corporate overhead costs.

Enron has continued to incur costs related to the resolution of issues associated with the bankruptcy and litigation with regards to certain employee benefit plans in which PGE employees previously participated. Enron billed PGE for a portion of these costs in 2004 and 2005 as work continued toward resolution of the issues. At December 31, 2005, PGE had $4 million payable to Enron related to these costs, including $1 million incurred in 2005. At December 31, 2004, PGE had $4 million payable to Enron related to employee benefits.

Portland General Holdings, Inc. - On June 27, 2003, PGH, a wholly owned subsidiary of Enron located in Portland, filed to initiate bankruptcy proceedings under the federal Bankruptcy Code. The PGH filing was procedurally consolidated with the Enron bankruptcy proceeding; however, the Chapter 11 Plan expressly did not pertain to PGH. No PGH subsidiaries are included in the bankruptcy filing. Substantially all assets of PGH were distributed or placed in segregated accounts and, on October 20, 2005, the Bankruptcy Court dismissed PGH's Chapter 11 case.

At December 31, 2004, PGE had outstanding accounts receivable from PGH of $5 million, comprised of $4 million related to employee benefit plans and $1 million for employee and administrative services provided by PGE to PGH in 2002. Based on management's assessment of the realizability of the receivable from PGH, a reserve of $1 million was recorded as of December 31, 2004. In October 2005, PGE received $4 million, representing the unreserved amount owed by PGH.

PGH II and its Subsidiary - PGH II, Inc. (PGH II), a wholly owned subsidiary of PGH, is the parent company of Portland General Distribution, LLC (PGDC), a telecommunications company which received services from PGE. PGH II and PGDC were not part of Enron's or PGH's bankruptcy proceedings. At December 31, 2004, PGE had outstanding accounts receivable from PGDC of $1 million for employee and other administrative services, offset by a $0.9 million uncollectible reserve. In June 2005, PGDC used the proceeds from an asset sale to pay the unreserved amounts that it owed to PGE.

PGE did not provide or bill PGH II for any services in 2005. In both 2004 and 2003, PGE billed PGH II and its subsidiaries $1 million for employee and other administrative services.

Following the distribution of new PGE common stock, neither PGH nor PGH II, as wholly owned subsidiaries of Enron, will be affiliates of PGE.

Other Subsidiaries - PGE also provides services to its consolidated subsidiaries, including funding under a cash management agreement and the sublease of office space in the Company's headquarters complex. Intercompany balances and transactions have been eliminated in consolidation.

PGE maintains no compensating balances and provides no guarantees for related parties.

Note 14 - Receivables and Refunds on Wholesale Market Transactions

Receivables - California Wholesale Market

As of December 31, 2005, PGE has net accounts receivable balances totaling approximately $63 million from the California Independent System Operator (ISO) and the California Power Exchange (PX) for wholesale electricity sales made from November 2000 through February 2001. The Company estimates that the majority of this amount was for sales by the ISO and PX to Southern California Edison Company and Pacific Gas & Electric Company (PG&E).

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

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

Refunds on Wholesale Transactions

California

On July 25, 2001, the FERC issued an order establishing the scope of and methodology for calculating refunds for wholesale sales transactions made between October 2, 2000 and June 20, 2001 in the spot markets operated by the ISO and PX. The order established evidentiary hearings to develop a factual record to provide the basis for the refund calculation. Several additional orders clarifying and further defining the methodology have since been issued by the FERC. Appeals of the FERC orders were filed and in August 2002 the U.S. Ninth Circuit Court of Appeals issued an order requiring the FERC to reopen the record to allow the parties to present additional evidence of market manipulation.

Also in August 2002, the FERC Staff issued a report that included a recommendation that natural gas prices used in the methodology to calculate potential refunds be reduced significantly.

In December 2002, a FERC administrative law judge issued a certification of facts to the FERC regarding the refunds, based on the methodology established in the 2001 FERC order rather than the August 2002 FERC Staff recommendation. On March 26, 2003, the FERC issued an order in the California refund case (Docket No. EL00-95) adopting in large part the certification of facts of the FERC administrative law judge but adopting the August 2002 FERC Staff recommendation on the methodology for the pricing of natural gas in calculating the amount of potential refunds. PGE estimates its potential liability under the modified methodology at between $40 million and $50 million, of which $40 million has been established as a reserve, as discussed above.

Numerous parties, including PGE, filed requests for rehearing of various aspects of the March 26, 2003 order, including the methodology for the pricing of natural gas. On October 16, 2003, the FERC issued an order reaffirming, in large part, the modified methodology adopted in its March 26, 2003 order. PGE does not agree with the FERC's methodology for determining potential refunds, and, on December 20, 2003 the Company appealed the FERC's October 16, 2003 order to the U.S. Ninth Circuit Court of Appeals; several other parties have also appealed the October 16, 2003 order. On May 12, 2004, the FERC issued an order that denied further requests for rehearing of the October 16, 2003 order. Although there continue to be miscellaneous orders issued in the underlying FERC proceeding, the Ninth Circuit Court of Appeals has now begun to hear the numerous appeals. It has bifurcated appeals of the existing cases into two phases. The first considered arguments regarding jurisdictional issues and the permissible scope of refund liability, both in terms of the time frame for which refunds were ordered and the types of transactions subject to refund. Briefing and oral argument have been completed on this first phase. As to the jurisdictional issues, on September 6, 2005, the Court ruled that FERC did not have jurisdiction to order municipal utilities and other governmental entities to make refunds for the sales they had made to the ISO and PX that are the subject of the refund proceeding. The Court has not yet issued a decision on the other issues pending in the first phase, and the Court agreed to defer the rehearing deadline on the jurisdictional issue decision until the remainder of the first phase is decided. The second phase will consider the issues relating to the refund methodology itself. PGE expects that the Court will establish additional phases as the continuing issues remaining before FERC become final and are appealed.

Also on May 12, 2004, the FERC issued a separate order that provided clarification regarding certain aspects of the methodology for California generators to recover fuel costs incurred to generate power that were in excess of the gas cost component used to establish the refund liability. On September 24, 2004, the FERC issued an order that denied requests for rehearing of its May 12, 2004 fuel cost order and also adopted a new methodology to allocate the excess amounts of fuel costs that California generators are permitted to recover. Additional clarifying orders continue to be issued periodically. Under the new allocation methodology of the September 24, 2004 order, PGE could be required to pay additional amounts in those hours when it was a net buyer in California spot markets, thus increasing its net refund liability. PGE does not expect that this order will materially increase the Company's potential refund exposure. Partly as a means of limiting its exposure to additional fuel costs, PGE has opted to become a participant in several settlements filed jointly by large generators and California parties, and approved by the FERC during 2004 and 2005.

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

In several of its underlying refund orders, the FERC has indicated that if marketers, such as PGE, believe that the level of their refund liability has caused them to incur an overall revenue shortfall for their sales to the ISO and PX during the refund period, they will be permitted to file a cost study to prove that they should be permitted to recover additional revenues in excess of the mitigated prices in order to cover their costs. By order issued August 8, 2005, FERC provided guidelines regarding the manner in which these studies should be conducted and the principles that should govern their preparation. PGE filed for rehearing of certain aspects of the August 8 order, and, on September 14, it filed its cost recovery study with FERC. The study showed that, pursuant to the principles set forth in the August 8 order and subject to rehearing, PGE's costs to serve the ISO and PX markets exceeded the revenues PGE will receive from those mitigated sales by over $27 million. By order issued

January 26, 2006, the FERC conditionally accepted PGE's September 14 cost filing, subject to PGE making a compliance filing to eliminate certain costs, to include additional revenues, and to supplement its analysis with additional cost, load, and resource data. On February 10, 2006, PGE submitted a compliance filing with two cases, in the alternative, that incorporated the FERC-required changes. The compliance filing shows a revenue deficit for PGE's sales to the ISO and PX (that is, a reduction to PGE's refund liability) of from approximately $20 million to approximately $30 million, depending on the methodology ultimately accepted by the Commission. Third parties have challenged PGE's compliance filing and requested that it be rejected in its entirety or that the cost offset be reduced to zero, and PGE has filed a response to those challenges. The procedure established by the FERC in the January 26 order also required each seller whose cost filing has been accepted to incorporate in its filing final ISO and PX settlement data and to provide its revised filing to the ISO and PX for further processing.

PGE believes that the FERC erred in certain of its findings in the January 26 order, and has filed a request for rehearing as to several issues. Due to the continuing uncertainty related to these matters, PGE has made no adjustment to the $40 million reserve previously established for the Company's potential liability, as described above.

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

Challenge of the California Attorney General to Market-Based Rates - On March 20, 2002, the California Attorney General filed a complaint with the FERC against various sellers in the wholesale power market, alleging that the FERC's authorization of market-based rates violated the 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 during the period October 2, 2000 - June 4, 2002 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 Court of Appeals. On September 8, 2004, the Court issued an opinion upholding the FERC's authority to approve market-based tariffs, but also holding that the FERC had the authority to order refunds, if quarterly filing of market-based sales transactions had not been properly made. The Court required the FERC, upon remand, to reconsider whether refunds should be ordered. On October 25, 2004, certain parties filed a petition for rehearing with the Court. In the refund case and in related dockets, the California Attorney General and other California parties have argued that refunds should be ordered retroactively to at least May 1, 2000. Management cannot predict the outcome of these proceedings or whether the FERC will order refunds retroactively to May 1, 2000, and if so, how such refunds would be calculated.

Anomalous Bidding Allegations

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

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

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

Note 15 - Future Ownership of PGE

Commencing on December 2, 2001, and from time to time thereafter, Enron, along with certain of its subsidiaries, filed to initiate bankruptcy proceedings under Chapter 11 of the federal Bankruptcy Code. Although PGE was not included in the bankruptcy, the common stock of PGE held by Enron is one of the assets of the bankruptcy estate.

Enron's 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 (Chapter 11 Plan), became effective on November 17, 2004. The Chapter 11 Plan and the related disclosure statement provide information about the assets that were in the bankruptcy estate, including the common stock of PGE, and how those assets or their proceeds will be distributed to the creditors.

Enron and PGE are moving forward to distribute new PGE common stock to the creditors of Enron and its reorganized debtor subsidiaries (collectively the Debtors) in accordance with the Chapter 11 Plan. Current PGE common stock held by Enron will be cancelled and 62,500,000 shares of new PGE common stock without par value will be distributed over time to the Debtors' creditors that hold allowed claims. PGE will issue at least 30 percent of the new PGE common stock to the Debtors' creditors that hold allowed claims, with the remainder issued to a Disputed Claims Reserve (DCR) where it will be held to be released over time to the Debtors' creditors holding allowed claims in accordance with the Chapter 11 Plan.

The distribution of new PGE common stock has been approved by all required regulatory agencies. If sufficient claims have been resolved in a timely manner to allow at least 30% of the new PGE common stock to be issued to Debtors' creditors, then issuance of new PGE common stock is expected to take place on or about April 3, 2006. Following issuance of the new PGE common stock to the Debtors' creditors and the DCR, PGE will no longer be a subsidiary of Enron.

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

The OPUC order approving the distribution of new PGE common stock includes 17 conditions that relate to, among other things: maintenance of PGE's financial strength during the conclusion of the Enron bankruptcy process, certain indemnifications for PGE from Enron related to Enron employee benefit plans and taxes, certain service quality measures, and additional direct access options for commercial and industrial customers. The indemnifications are expected to be included in a separation agreement between Enron and PGE, which is expected to be executed at the time of the issuance of new PGE common stock.

On February 10, 2006, the City of Portland appealed the OPUC Order in both the Marion County Circuit Court and the Oregon Court of Appeals. The City filed its appeals in both courts due to the jurisdictional uncertainty created by new Oregon law governing appeals of OPUC decisions. In its appeal to the Circuit Court, the City alleges that the OPUC made its decision on an inadequate record, failed to enter adequate findings in support of its decision, abused the discretion granted it by Oregon law, and based its decision on a statute that constituted an unlawful delegation from the Oregon Legislature. The City requests the OPUC Order be modified, reversed or remanded. In the Court of Appeals filing, the City alleges that it is an aggrieved party and asks for judicial review without further details. On February 23, 2006 the OPUC filed a Motion to Hold Case in Abeyance with the Marion County Circuit Court in order to seek summary determination from the Court of Appeals regarding the proper court to hear the City's appeal. The City and other defendants to the action, including PGE, did not oppose the motion. The Circuit Court has not ruled on this motion.

On February 13, 2006, the URP filed with the OPUC an application for reconsideration of the OPUC Order. The URP requests that the OPUC reconsider its order in light of a new Oregon Statute (Senate Bill 408), governing the rate treatment of income taxes included by Oregon utilities in rates. The URP alleges the stock distribution would allow PGE to deconsolidate for income tax purposes and frustrate future rate benefits Senate Bill 408 would allegedly produce. On February 28, 2006, PGE, CUB, and the OPUC staff filed oppositions to URP's application for reconsideration. Also on February 28, 2006, the City filed in support of URP's application and added new grounds for reconsideration of the OPUC Order. PGE filed in opposition to the City's new grounds for reconsideration on March 13, 2006. The OPUC has 60 days from the filing of an application for reconsideration to act on the application or it is deemed denied.

PGE has filed an original listing application with the New York Stock Exchange for the listing of the new PGE common stock under the ticker symbol POR.

Enron has also indicated that, in accordance with its ongoing efforts to maximize the value of the Enron bankruptcy estate, Enron will continue to consider credible offers to purchase PGE's common stock until the new PGE common stock is distributed. Following distribution of the new PGE common stock, approval of any offer to purchase the new PGE common stock from the DCR will be the responsibility of the DCRO, in accordance with guidelines approved by the Bankruptcy Court.

Note 16 - Restatement of Prior Period Financial Statements

Pension and Other Post Retirement Benefits
Prepaid pension costs of $78 million and accrued liabilities for other post retirement benefits of $9 million have been restated to reclassify the balances from current assets (liabilities) to non-current assets (liabilities) on the Consolidated Balance Sheet as of December 31, 2004.

Non-Utility Property - Asset Retirement Obligation
During the financial closing process for the year ended December 31, 2005, PGE determined that a $20 million liability established in 1997 for estimated future demolition and remediation costs related to tenant leasehold improvements on non-utility land located adjacent to the Company's Sullivan Hydro Plant did not include consideration of salvage values. Inclusion of salvage values would have reduced the recorded liability by $8 million (to $12 million) and adjusted related deferred taxes by $3 million, resulting in a $5 million increase in the January 1, 2003 balance of retained earnings, from $488 million (as previously reported) to $493 million (as restated).

In addition, upon the January 1, 2003 adoption of SFAS No. 143, Accounting for Asset Retirement Obligations, the Company should have further reduced the recorded liability by $4 million (to its estimated $8 million fair value) and adjusted related deferred income taxes by $2 million.

A summary of the significant effects of the above restatements are as follows (in millions):

	Consolidated Statement of Income	
For the year ended December 31, 2003	**As Previously Reported**	**As Restated**
Cumulative effect of a change in accounting principle, net of related taxes [Previously reported $(1); Restated $(3)]	$ 2	$ 4
Net Income	58	60

	Consolidated Balance Sheet	
As of December 31, 2004	**As Previously Reported**	**As Restated**
Prepayments and other [(1)]	$ 113	$ 35
Deferred Charges and Other - Miscellaneous [(1)]	25	103
Retained earnings [(2)]	637	644
Accounts payable and other accruals [(1)]	182	173
Deferred income taxes [(2)]	308	313
Accumulated asset retirement obligation [(2)]	16	24
Other - Miscellaneous [(1)] [(2)]	37	26

[(1)] Pension and Other Post Retirement Benefits
[(2)] Non-Utility Property - Asset Retirement Obligation

In addition, the Company has restated the presentation of the activities within the Nuclear Decommissioning Trust to disclose amounts on a gross basis, rather than on a net basis, in the Consolidated Statements of Cash Flow.

QUARTERLY COMPARISON FOR 2005 AND 2004 (Unaudited)

	March 31	June 30	September 30 (In Millions)	December 31	Total
2005					
Operating revenues	$371	$333	$355	$387	$1,446
Net operating income (*)	53	32	36	5	126
Net income (loss) (*)	38	16	19	(9)	64
Income (loss) available for Common stock	38	16	19	(9)	64
2004					
Operating revenues	$395	$332	$348	$379	$1,454
Net operating income	48	38	20	44	150
Net income	32	22	10	28	92
Income available for Common stock	32	22	10	28	92

(*) On October 22, 2005, the Boardman coal plant was taken out of service for repair of the plant's steam turbine rotor. PGE incurred significant incremental power costs during the fourth quarter to replace the plant's generation, the after-tax effect of which was approximately $25 million. For further information, see "Boardman Coal Plant - Extended Outage" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

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 Rules 13a-15(e) and 15d-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) Changes in Internal Control Over Financial Reporting. There have not been any changes in the Company's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the fourth quarter 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

Directors of the Registrant [1]

JOHN W. BALLANTINE, age 60 — Director since February 1, 2004

Mr. Ballantine has been an active private investor since 1998, when he retired from First Chicago NBD Corporation where he served as Executive Vice President and Chief Risk Management Officer. During his 28-year career with First Chicago, Mr. Ballantine was responsible for International Banking operations, New York operations, Latin American Banking, Corporate Planning, US Financial Institutions business and a variety of trust operations. He also serves on the Boards of DWS Funds, First Oak Brook Bancshares and the Oak Brook Bank, Healthways, Inc., and Prisma Energy International Inc. (an Enron affiliate). Mr. Ballantine served as a director of Enron from May 2002 until November 2004.

Mr. Ballantine is the Chair of PGE's Compensation Committee and a member of PGE's Audit Committee.

ROBERT S. BINGHAM, age 57 — Director since January 18, 2003

Mr. Bingham has served as a consultant with Kroll Zolfo Cooper, LLC (formerly Zolfo Cooper, LLC) since February 1999. During this time with Kroll Zolfo Cooper, LLC, he has worked on the Enron bankruptcy since February 2002 and served as Interim Chief Financial Officer and Interim Treasurer for Enron from November 2004 until December 16, 2005. He is a certified public accountant and a certified insolvency and restructuring advisor.

Mr. Bingham is the Chair of PGE's Audit Committee and a member of PGE's Compensation Committee.

DAVID A. DIETZLER, age 62 — Director since January 25, 2006

Mr. Dietzler has been a CPA for nearly 37 years and retired as a partner of KPMG LLP, a public accounting firm, in 2004. During the past 10 years with KPMG LLP he served in both administrative and client service roles which included serving on the firm's Governance, Nominating and Board Process and Evaluation committees, and was the Pacific Northwest partner in charge of the Audit Practice for KPMG's offices in Anchorage, Boise, Billings, Portland, Salt Lake City and Seattle.

Directors of the Registrant [1] - Continued

PEGGY Y. FOWLER, age 54 Director since August 14, 1998

Ms. Fowler has served as Chief Executive Officer and President of PGE since April 2000 and was Chair of the Board until January 31, 2004. She served as President from February 1998 until April 2000. She served as Chief Operating Officer of PGE Distribution Operations from November 1996 until February 1998. Previously, she served in various positions with PGE, including Senior Vice President Customer Service and Delivery and Vice President Power Production and Supply. She also serves on the Board of The Regence Group.

Ms. Fowler also served as President of Portland General Holdings, Inc.[2] (an Enron affiliate) from March 1999 until June 2003.

MARK B. GANZ, age 45 Director since January 25, 2006

Mr. Ganz is President, Chief Executive Officer and Director of The Regence Group, a parent corporation of various companies offering health, life and disability products and services under the BlueCross and BlueShield trademarks. Prior to his current position, Mr. Ganz served as President and Chief Operating Officer of The Regence Group from 2003 to 2004 and President of Regence BlueCross BlueShield of Oregon from 2001 to 2003. He was Senior Vice President, Chief Legal & Compliance Officer and Corporate Secretary of the Regence Group from 1996 to 2001.

CORBIN A. MCNEILL, JR., age 66 Director since February 1, 2004

Mr. McNeill is Chair of the Board. In 2002, he retired as Chairman and CEO of Exelon Corporation, which was formed in October 2000 by the merger of PECO Energy Company and Unicom Corporation. Prior to the merger, he was Chairman, President and CEO of PECO Energy. Mr. McNeill completed a 20-year career with the U.S. Navy in 1981 and then joined the New York Power Authority as resident manager of the James A. Fitzpatrick nuclear power plant. He also worked at Public Service Electric and Gas Company prior to joining PECO in 1988 as Executive Vice President, Nuclear. He serves on the Boards of Ontario Power Generation, Associated Electric & Gas Services Limited, Owens-Illinois Corporation, and Silver Spring Networks. Mr. McNeill served as a Director of Enron from May 2002 until November 2004.

ROBERT G. MILLER, age 62 Director since January 25, 2006

Mr. Miller is currently Chair of the Board of Rite Aid Corporation, a retail pharmacy chain, which position he has held since 1999. He also served as Chief Executive Officer of Rite Aid Corporation from 2000 to 2003. He was Vice Chairman and Chief Operating Officer of The Kroger Co., a grocery supermarket company, following Kroger's May 1999 acquisition of Fred Meyer, Inc. (a food, drug and general merchandise chain) until December 1999. He served as Chairman of the Board and Chief Executive Officer of Fred Meyer, Inc. from 1991-1998 and Vice Chairman of the Board and Chief Executive Officer from 1998 to May 1999. Mr. Miller also serves as a director of Harrah's Entertainment, Inc. a gaming company owning, operating, and managing casinos; and Nordstrom, Inc. a fashion specialty retailer. He also currently serves as Chair of the Board of Wild Oats Markets, Inc., a natural foods supermarket chain.

Directors of the Registrant [1] - Continued

M. LEE PELTON, Ph. D., age 55 Director since January 25, 2006

Dr. Pelton was appointed President of Willamette University in July 1999. From 1991 until 1998, he was the dean of Dartmouth College. Prior to 1991, he held faculty and administrative posts at Colgate University and Harvard University. Dr. Pelton serves as the Chairman of the American Council on Education and a member of the Harvard University Board of Overseers and Board of Trustees for the Oregon Health & Science University Foundation. He also serves on the Board of PLATO Learning, Inc.

MARIA M. POPE, age 41 Director since January 25, 2006

Ms. Pope was appointed Vice President-General Manager, Wood Products Division of Pope & Talbot, Inc., a pulp and wood product company, in December 2003. She served as Vice President, Chief Financial Officer and Secretary from 1999 to 2003, and has held various financial positions since joining the Company in 1995. Ms. Pope previously worked for Levi Strauss & Co. and Morgan Stanley & Co., Inc. She currently serves as a member of the Board of Premera Blue Cross, a nonprofit, independent regional health plan.

ROBERT T. F. REID, age 55 Director since January 25, 2006

Mr. Reid is currently Chair and Corporate Director of British Columbia Transmission Corp., which position he has held since 1999. Mr. Reid served as president of Duke Energy's Canadian operations from 2002 to 2003. Prior to Duke's acquisition of Westcoast Energy in March 2002, he served as Executive Vice President and Chief Operating Officer of Westcoast. Prior to his appointment as Westcoast's Chief Operating Officer in 2001, Mr. Reid held senior executive positions in both the natural gas industry and in government service, including Union Gas Ltd., Westcoast Energy International, Pan-Alberta Gas, Foothills Pipe Lines, and the Independent Petroleum Association of Canada. He also serves as Director of Greystone Capital Management Inc., Investment Saskatchewan Inc., and the Canadian Education Centre Network.

RAYMOND S. TROUBH, age 79 Director since April 1, 2004

Mr. Troubh has been a self-employed financial consultant for more than five years. He also serves on the Boards of Diamond Offshore Drilling, Inc., General American Investors Company, Gentiva Health Services, Inc., Petrie Stores Liquidating Trust (Trustee), Triarc Companies, Inc., and Hollinger International, Inc. Mr. Troubh served as a director of Enron from November 2001 until November 2004 (including Chairman of the Board from November 2002 until November 2004).

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(1) As of February 28, 2006. Directors of PGE hold office until the next annual meeting of shareholders or until their respective successors are duly elected and qualified. Robert H. Walls, Jr. resigned as a Director of PGE, effective August 31, 2005.

(2) Portland General Holdings, Inc. filed for bankruptcy protection on June 27, 2003. PGH's bankruptcy case was dismissed by the Bankruptcy Court on October 20, 2005.

Executive Officers of the Registrant[1]

Name	Age	Business Experience
Peggy Y. Fowler Chief Executive Officer and President	54	Appointed to current position on April 1, 2000. Served as President from February 1998 until appointed to current position. Served as Chief Operating Officer of PGE Distribution Operations from November 1996 until February 1998. Previously served in various positions with PGE, including Senior Vice President, Customer Service and Delivery, and Vice President, Power Production and Supply. Ms. Fowler also served as President of Portland General Holdings, Inc.[2] (an Enron affiliate) from March 1999 until June 2003.
James J. Piro Executive Vice President, Finance, Chief Financial Officer and Treasurer	53	Appointed to current position on July 25, 2002. Served as Senior Vice President Finance, Chief Financial Officer and Treasurer from May 2001 until appointed to current position. Served as Vice President, Chief Financial Officer and Treasurer from November 2000 until May 2001. Served as Vice President, Business Development from February 1998 until November 2000. Served as General Manager, Planning Support, Analysis and Forecasting, from 1992 until 1998. Mr. Piro also served as Chief Financial Officer and Senior Vice President of Portland General Holdings, Inc.[2] (an Enron affiliate) from July 2001 until June 2003.
Arleen N. Barnett Vice President, Administration, Corporate Compliance Officer	54	Appointed to current position on August 2, 2004. Served as Vice President, Human Resources and Information Technology and as Corporate Compliance Officer from May 2001 until appointed to current position. Served as Vice President, Human Resources from February 1998 until May 2001. Served as Manager, Human Resources Operations from 1989 until 1997 and Manager, Generating Division from 1987 to 1989. Ms. Barnett also served as Vice President, Human Resources of Portland General Holdings, Inc.[2] (an Enron affiliate) from March 1998 until June 2003.

Executive Officers of the Registrant[1]

Name	Age	Business Experience
Carol A. Dillin Vice President, Public Policy	48	Appointed to current position on February 1, 2004. Served as Director of Public Affairs and Corporate Communications from April 1998 until appointed to current position. Served as Manager of Corporate Communications from November 1991 to April 1998.
Stephen R. Hawke Vice President, Customer Service and Delivery	56	Appointed to current position on August 2, 2004. Served as Vice President, System Engineering, Utility Services and Customer Service from October 2003 until appointed to current position. Served as Vice President, System Engineering and Utility Services from July 1997 until October 2003. Served as General Manager, System Planning and Engineering from May 1995 until July 1997. Served as Manager, Response and Restoration from May 1993 until May 1995. Served in a variety of Transmission and Distribution management positions from 1972 to 1993.
Ronald W. Johnson Vice President, Customers and Economic Development	55	Appointed to current position on August 2, 2004. Served as Vice President, Customer Resource Strategy and Generation Engineering from July 2002 until appointed to current position. Served as Vice President, Power Supply, Resource Development and Engineering Services from January 2001 until July 2002. Appointed Vice President, Deputy General Counsel and Assistant Secretary in May 1999. Served as Deputy General Counsel from 1989 until January 2001.
Pamela G. Lesh Vice President, Regulatory Affairs and Strategic Planning	49	Appointed to current position on August 2, 2004. Served as Vice President, Regulatory and Federal Affairs from June 2002 until appointed to current position. Served as Vice President, Public Policy and Regulatory Affairs from May 2001 until June 2002. Served as Vice President, Rates and Regulatory Affairs from December 1998 until May 2001. Served as Vice President, Strategy and Product Management with ConneXt Corp. of Seattle from June 1997 until December 1998. Served as Vice President, Rates and Regulatory Affairs from November 1996 to June 1997. Served as Director, Regulatory Policy from August 1989 to October 1996.

Executive Officers of the Registrant[1]

Name	Age	Business Experience
James F. Lobdell Vice President, Power Operations and Resource Planning	47	Appointed to current position on August 2, 2004. Served as Vice President, Power Operations from September 2002 until appointed to current position. Served as Vice President, Risk Management Reporting, Controls and Credit from May 2001 until September 2002. Served as Senior Director of Business Development from July 1999 to May 2001. Served as Vice President, Finance and Administration for FirstPoint Utility Solutions from 1997 to 1998.
Joe A. McArthur Vice President, Distribution	58	Appointed to current position on July 1, 1997. Served as Manager of Western Region from May 1996 until appointed to current position. Served as Manager, System Planning from May 1995 until May 1996. Served as Commercial and Industrial Market Manager from 1993 to 1995.
Douglas R. Nichols Vice President, General Counsel and Secretary	63	Appointed to current position on May 1, 2001. Served as Acting Deputy General Counsel from February 2001 until appointed to current position. Served as Assistant General Counsel from May 1991 to February 2001. Mr. Nichols also served as General Counsel of Portland General Holdings, Inc.[2] (an Enron affiliate) from June 2001 until June 2003.
Stephen M. Quennoz Vice President, Nuclear and Power Supply/ Generation	58	Appointed to current position on August 2, 2004. Served as Vice President, Generation from January 2001 until appointed to current position. Served as Vice President Nuclear and Thermal Operations from October 1998 until January 2001. Joined PGE in 1991 and held the position of Trojan Site Executive and Plant General Manager from 1993 to 1998.

[1] As of February 28, 2006. Officers of PGE are elected for one-year terms or until their successors are elected and qualified.

[2] Portland General Holdings, Inc. filed for bankruptcy protection on June 27, 2003. PGH's bankruptcy case was dismissed by the Bankruptcy Court on October 20, 2005.

Audit Committee Financial Expert

The Board has determined that Robert S. Bingham is an "audit committee financial expert" as that term is defined in Item 401(h) of Regulation S-K. However, Mr. Bingham is not "independent" as defined by the applicable listing standards of the New York Stock Exchange.

Code of Ethics

The Company has adopted a code of ethics applicable to PGE's chief executive officer, chief financial officer, chief accounting officer, and controller, which satisfies the definition of "code of ethics" under applicable rules of the SEC. The code of ethics is publicly available on the Company's web site at www.portlandgeneral.com. If the Company makes any substantive amendments to this code, or grants any waivers from a provision of this code to the Company's chief executive officer, chief financial officer, chief accounting officer, or controller, the Company will disclose on the Company's web site the nature of the amendment or waiver, its effective date, and to whom it applies.

Section 16 (a) Beneficial Ownership Reporting Compliance

Section 16 of the Securities Exchange Act of 1934 requires the Company's Directors and Executive Officers to file a Form 3 with the SEC within ten days of becoming a PGE Director or Executive Officer, and thereafter to file various reports concerning holdings of, and transactions in, equity securities of PGE. Copies of those filings must be furnished to the Company. To the best of our knowledge, PGE directors and executive officers complied with all applicable Section 16(a) filing requirements in 2005.

Item 11. Executive Compensation

Summary Compensation Table

The following indicates total compensation earned for the years ended December 31, 2005, 2004 and 2003 by the Chief Executive Officer and the four most highly compensated executive officers of PGE (the "Named Executive Officers").

		Annual Compensation		
Name and Principal Position	Year	Salary[1]	Bonus	All Other Compensation[2]
Peggy Y. Fowler	2005	$383,764	$370,759	$ 15,700
Chief Executive Officer	2004	350,004	376,744	13,647
and President	2003	350,004	240,000	413,792
James J. Piro	2005	239,744	115,466	13,519
Executive Vice President, Finance	2004	227,379	138,857	11,933
Chief Financial Officer and Treasurer	2003	215,129	160,000	136,790
Stephen M. Quennoz	2005	206,642	96,844	9,771
Vice President, Nuclear and	2004	193,885	115,815	8,625
Power Supply/Generation	2003	191,411	130,000	8,688
Douglas R. Nichols	2005	209,625	86,068	12,519
Vice President, General Counsel and	2004	193,336	124,730	10,719
Secretary	2003	190,008	138,000	119,716
Stephen R. Hawke	2005	193,500	79,448	10,547
Vice President, Customer Service and	2004	178,336	115,042	9,619
Delivery	2003	175,008	95,000	115,450

(1) Amounts shown include compensation earned by the executive officer, as well as amounts earned but deferred at the election of the officer.

(2) Other compensation includes: (i) split dollar term life insurance cost; (ii) company contributions to the PGE Corp Savings Plan (401k) during 2005, Enron Corp. Savings Plan (401k) for 2004-2003 and the Management Deferred Compensation Plan (MDCP); (iii) earnings on amounts in the MDCP which are greater than 120 percent of the federal long-term rate which was in effect at the time the rate was set; and (iv) payments made under retention agreements, if any. The following are amounts for 2005:

	Split Dollar Insurance Cost	Contributions to 401(k) and MDCP	Above Market Interest on MDCP	Total
Peggy Y. Fowler	$720	$14,980	$ -	$15,700
James J. Piro	-	13,296	223	13,519
Stephen M. Quennoz	-	9,151	620	9,771
Douglas R. Nichols	-	12,519	-	12,519
Stephen R. Hawke	-	10,400	147	10,547

Pension Plans

Estimated annual retirement benefits payable to the Named Executive Officers are shown in the table below. Amounts in the first line of the table reflect payments from the pension plan for PGE employees (PGE Pension Plan) at the maximum compensation base of $220,000 (unreduced benefit at age 65). Additional amounts in the table reflect payments from the PGE Pension Plan and Supplemental Executive Retirement Plan (SERP) on a combined basis (unreduced benefit at age 62 or at combined age and years of service of 85).

Pension Plan Table
Estimated Annual Retirement Benefit
Straight-Life Annuity

	Final Average Earnings	Years of Service 15	20	25	30	35
Pension Plan Only	$220,000	$52,439	$69,918	$87,398	$104,878	$110,378
Pension Plan and SERP	700,000	-	-	-	420,000	420,000
	800,000	-	-	-	480,000	480,000

Pursuant to rules under the Internal Revenue Code of 1986, as amended, a pension plan may not base benefits on annual compensation in excess of $220,000 or pay annual benefits in excess of $175,000. These limits are periodically adjusted for changes in the cost of living. Compensation used to calculate benefits under the PGE Pension Plan is based on a five-year average of base salary only (the highest 60 consecutive months within the last 10 years). PGE Pension Plan benefits are reduced by 2% annually for those that retire at ages 60 to 64 and 5% annually for those that retire at ages 55 to 59.

Compensation used to calculate benefits under the combined PGE Pension Plan and SERP is based on a three-year average of base salary and annual performance bonus amounts (the highest 36 consecutive months within the last 10 years), as reported in the Summary Compensation Table. Surviving spouses receive one half the participant's retirement benefit from the SERP, plus the joint and survivor benefit, if any, from the PGE Pension Plan. In addition to the aforementioned annual retirement benefits, an additional temporary Social Security Supplement is paid until the participant is eligible for social security retirement benefits. Retirement benefits are not subject to any deduction for social security. The minimum retirement age under the SERP is 55. The SERP was closed to new participants in 1997.

Peggy Y. Fowler is a participant in both plans. The other Named Executive Officers participate only in the PGE Pension Plan. The Named Executive Officers have the following number of years of service with the Company: Peggy Y. Fowler, 32; James J. Piro, 26; Stephen M. Quennoz, 15; Douglas R. Nichols, 15; and, Stephen R. Hawke, 32. Under the Company's SERP, Peggy Y. Fowler is eligible to retire without a reduction in benefits upon attainment of the age of 55.

Compensation of Directors

In 2005, non-management directors received fees for their Board service, including $80,000 per year for serving on the Board and $20,000 per year for serving as Chair of the Board or as Chair of the Audit Committee. Director fees are paid quarterly and apportioned from the date of appointment.

The following table indicates total fees paid to outside directors for their Board service during 2005.

Name	Board Service Fees Paid: Directorship	Chair	Total
John W. Ballantine (director since February 1, 2004)	$ 80,000	$ -	$ 80,000
Corbin A. McNeill, Jr. (director since February 1, 2004)	80,000	20,000	100,000
Raymond S. Troubh (director since April 1, 2004)	80,000	-	80,000

Compensation Committee Interlocks and Insider Participation
The Compensation Committee of the PGE Board of Directors is responsible for developing and administering compensation philosophy. Committee members during 2005 were John W. Ballantine, Robert S. Bingham, and Robert H. Walls, Jr. Mr. Walls resigned as Chairman of the Compensation Committee effective January 9, 2005. Mr. Ballantine was appointed as Committee Chairman on January 10, 2005. Salary increases, annual incentive awards, and long-term incentive grants (if any) are reviewed annually to ensure consistency with PGE's total compensation philosophy. No Compensation Committee interlocks or insider participation requiring disclosure under Item 402(j) of Regulation S-K existed during 2005.

Item 12. Security Ownership of Certain Beneficial Owners and Management

PGE is a wholly owned subsidiary of Enron.

Item 13. Certain Relationships and Related Transactions

There are no relationships or transactions required to be disclosed under Item 404 of Regulation S-K.

Item 14. Principal Accounting Fees and Services

The Company incurred the following fees for services rendered by Deloitte & Touche LLP (Deloitte & Touche) and, its predecessor auditor, PricewaterhouseCoopers LLP (PwC) for the years ended December 31, 2005 and 2004.

Audit Fees

Aggregate fees billed or expected to be billed for professional services rendered for the audit of PGE's consolidated financial statements for the years ended December 31, 2005 and 2004 and for the review of the interim consolidated financial statements included in quarterly reports are set forth below. Audit Fees also include services normally provided in connection with statutory and regulatory filings or engagements and assistance with and review of documents filed with the SEC.

	PwC (a)	Deloitte & Touche
2005	$ -	$835,000
2004	11,770 (b)	796,487 (b)

(a) Fees for services provided to consent to the inclusion of their audit report in PGE's 2004 Form 10-K after dismissal on January 9, 2004.
(b) Include adjustments to amounts previously reported to reflect actual amounts billed.

Audit-Related Fees

Aggregate fees billed in the year indicated for assurance and related services that are reasonably related to the performance of the audit or review of PGE's consolidated financial statements and are not reported under "Audit Fees" are set forth below. These services include employee benefit plan audits, due diligence related to the planned stock distribution and Enron auction process for PGE, attest services that are not required by statute or regulation, and consultations concerning financial accounting and reporting standards.

	PwC (c)	Deloitte & Touche
2005	$ -	$141,637
2004	720	129,856

(c) Fees for consultation concerning financial accounting and reporting standards prior to dismissal.

Tax Fees

Tax Fees billed in the year indicated for professional tax services as set forth below.

	PwC	Deloitte & Touche
2005	$ -	$ -
2004	-	-

All Other Fees

Aggregate fees billed in the year indicated for all other products and services not included in the above three categories are set forth below. These primarily include reference products related to income taxes and financial accounting matters.

	PwC	Deloitte & Touche
2005	$ -	$ 24,262
2004	-	16,373

Audit Committee Policy for Pre-Approval of Audit and Permissible Non-Audit Services of Independent Auditors

The Audit Committee's policy requires pre-approval of all audit and permissible non-audit services provided by the independent auditors. These services may include audit services, audit-related services, tax services and other services. Pre-approval is generally provided for up to one year and any pre-approval is detailed as to the particular service or category of services and is generally subject to a specific budget. Management and the independent auditors are required to periodically report to the Audit Committee regarding the extent of services provided by the independent auditors in accordance with what was pre-approved, and the fees for the services rendered to date. The Audit Committee may also pre-approve particular services on a case-by-case basis. All audit and permissible non-audit services provided by the independent auditors during 2005 were pre-approved by the Audit Committee.

Part IV

Item 15. Exhibits, Financial Statement Schedules

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

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Exhibits

See Exhibit Index on Page 147 of this report.

Portland General Electric Company and Subsidiaries
Schedule II - Consolidated Valuation and Qualifying Accounts
For the Years Ended December 31, 2005, 2004, and 2003
(In Millions)

	Allowance for Uncollectible Accounts
Balance at January 1, 2003	$ 109
Provision charged to income	24
Amounts written off, less recoveries	(9)
Balance at December 31, 2003	124
Balance at January 1, 2004	124
Provision charged to income	11
Amounts written off, less recoveries	(85)
Balance at December 31, 2004	50
Balance at January 1, 2005	50
Provision charged to income	7
Amounts written off, less recoveries	(7)
Balance at December 31, 2005	$ 50

SIGNATURES

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

Portland General Electric Company

March 15, 2006

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	March 15, 2006
/s/ James J. Piro James J. Piro	Executive Vice President, Finance Chief Financial Officer and Treasurer	March 15, 2006
/s/ Kirk M. Stevens Kirk M. Stevens	Controller and Assistant Treasurer	March 15, 2006
*John W. Ballantine	Director	March 15, 2006
*Robert S. Bingham	Director	March 15, 2006
*David A. Dietzler	Director	March 15, 2006
*Mark B. Ganz	Director	March 15, 2006
*Corbin A. McNeill, Jr.	Director	March 15, 2006
*Robert G. Miller	Director	March 15, 2006
*M. Lee Pelton	Director	March 15, 2006
*Maria M. Pope	Director	March 15, 2006
*Robert T.F. Reid	Director	March 15, 2006
*Raymond S. Troubh	Director	March 15, 2006

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

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES

EXHIBIT INDEX

Number		Exhibit
(2)		**Plan of Acquisition, Reorganization, Arrangement, Liquidation or Succession**
2.1	*	Amended and Restated Agreement and Plan of Merger, dated as of July 20, 1996 and amended and restated as of September 24, 1996 among Enron Corp, Enron Oregon Corp and Portland General Corporation [Amendment 1 to S-4 Registration Nos. 333-13791 and 333-13791-1, dated October 10, 1996, Exhibit No. 2.1].
(3)		**Articles of Incorporation and Bylaws**
3.1	*	Copy of Articles of Incorporation of Portland General Electric Company [Registration No. 2-78085, Exhibit (4)].
3.2	*	Certificate of Amendment, dated July 2, 1987, to the Articles of Incorporation of Portland General Electric Company limiting the personal liability of directors [Form 10-K for the fiscal year ended December 31, 1987, Exhibit (3)].
3.3	*	Articles of Amendment to Articles of Incorporation of Portland General Electric Company, dated July 8, 1992, for series of Preferred Stock ($7.75 Series) [Registration Statement No. 33-46357, Exhibit (4)(a)].
3.4	*	Articles of Amendment to Articles of Incorporation of Portland General Electric Company, dated September 30, 2002, creating Limited Voting Junior Preferred Stock [Form 10-Q for the quarter ended September 30, 2002, Exhibit (3)].
3.5	*	Amended and Restated Bylaws of Portland General Electric Company as amended on February 1, 2004 [Form 10-K for the fiscal year ended December 31, 2003, Exhibit (3)].
(4)		**Instruments defining the rights of security holders, including indentures**
4.1	*	Portland General Electric Company Indenture of Mortgage and Deed of Trust dated July 1, 1945 [Form 8, Amendment No. 1 dated June 14, 1965].
4.2	*	Fortieth Supplemental Indenture dated October 1, 1990 [Form 10-K for the fiscal year ended December 31, 1990, Exhibit (4)].
4.3	*	Forty-First Supplemental Indenture dated December 1, 1991 [Form 10-K for the fiscal year ended December 31, 1991, Exhibit (4)].
4.4	*	Forty-Second Supplemental Indenture dated April 1, 1993 [Form 10-Q for the quarter ended March 31, 1993, Exhibit (4)].
4.5	*	Forty-Third Supplemental Indenture dated July 1, 1993 [Form 10-Q for the quarter ended September 30, 1993, Exhibit (4)].
4.6	*	Forty-Fifth Supplemental Indenture dated May 1, 1995 [Form 10-Q for the quarter ended June 30, 1995, Exhibit (4)].

PORTLAND GENERAL ELECTRIC COMPANY
AND SUBSIDIARIES

EXHIBIT INDEX

Number		Exhibit
4.7	*	Forty-Seventh Supplemental Indenture dated December 14, 2001 [Form 10-K for the fiscal year ended December 31, 2001, Exhibit (4)].
4.8	*	Supplemental Indenture dated April 30, 1999 [S-3 Registration No. 333-77469, dated April 30, 1999, Exhibit 4(c)].
		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)].
		The following 12 exhibits were filed in conjunction with the 1985 Boardman/Intertie Sale:
10.3	*	Long-term Power Sale Agreement dated November 5, 1985 [Form 10-K for the fiscal year ended December 31, 1985, Exhibit (10)].
10.4	*	Long-term Transmission Service Agreement dated November 5, 1985 [Form 10-K for the fiscal year ended December 31, 1985, Exhibit (10)].
10.5	*	Participation Agreement dated December 30, 1985 [Form 10-K for the fiscal year ended December 31, 1985, Exhibit (10)].
10.6	*	Lease Agreement dated December 30, 1985 [Form 10-K for the fiscal year ended December 31,1985, Exhibit (10)].
10.7	*	PGE-Lessee Agreement dated December 30, 1985 [Form 10-K for the fiscal year ended December 31, 1985, Exhibit (10)].
10.8	*	Asset Sales Agreement dated December 30, 1985 [Form 10-K for the fiscal year ended December 31, 1985, Exhibit (10)].
10.9	*	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)].

PORTLAND GENERAL ELECTRIC COMPANY
AND SUBSIDIARIES

EXHIBIT INDEX

Number		Exhibit
10.10	*	Supplemental Bill of Sale dated December 30, 1985 [Form 10-K for the fiscal year ended December 31, 1985, Exhibit (10)].
10.11	*	Trust Agreement dated December 30, 1985 [Form 10-K for the fiscal year ended December 31, 1985, Exhibit (10)].
10.12	*	Tax Indemnification Agreement dated December 30, 1985 [Form 10-K for the fiscal year ended December 31, 1985, Exhibit (10)].
10.13	*	Trust Indenture, Mortgage and Security Agreement dated December 30, 1985 [Form 10-K for the fiscal year ended December 31, 1985, Exhibit (10)].
10.14	*	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)].
	Executive Compensation Plans and Arrangements	
10.15	*	Portland General Electric Company Annual Cash Incentive MasterPlan for 2004 [Form 10-K for the fiscal year ended December 31, 2003, Exhibit (10)].
10.16	*	Updated summary description of the Portland General Electric Company Annual Cash Incentive Master Plan for 2004 [Form 8-K dated February 12, 2005, Exhibit (10)].
10.17	*	Summary description of the Portland General Electric Company 2005 Annual Cash Incentive Plan [Form 8-K dated March 29, 2005, Exhibit (10)].
10.18	*	Portland General Electric Company Management Deferred Compensation Plan, dated March 12, 2003 [Form 10-Q for the quarter ended March 31, 2003, Exhibit (10)].
10.19	*	Portland General Electric Company Severance Pay Plan for Executive Employees, dated June 15, 2005 [Form 10-K dated June 15, 2005, Exhibit (10)].
10.20	*	Portland General Electric Company Outplacement Assistance Plan, dated June 15, 2005 [Form 10-K dated June 15, 2005, Exhibit (10)].
10.21	*	Portland General Electric Company 2005 Management Deferred Compensation Plan, dated March 4, 2005 (Form 10-K for the fiscal year ended December 31, 2004).
10.22	*	Portland General Electric Company Supplemental Executive Retirement Plan, dated March 12, 2003 [Form 10-Q for the quarter ended March 31, 2003, Exhibit (10)].
10.23	*	Portland General Electric Company Senior Officers' Life Insurance Benefit Plan, dated March 12, 2003 [Form 10-Q for the quarter ended March 31, 2003, Exhibit (10)].
10.24	*	Portland General Electric Company Umbrella Trust for Management, dated March 12, 2003 [Form 10-Q for the quarter ended March 31, 2003, Exhibit (10)].

PORTLAND GENERAL ELECTRIC COMPANY
AND SUBSIDIARIES

EXHIBIT INDEX

Number		Exhibit
10.25	*	Director Compensation Arrangement [Form 10-K for the fiscal year ended December 31, 2003, Exhibit (10)].
10.26	*	Portland General Electric Company 2006 Stock Incentive Plan [Form 8-K dated February 21, 2006, Exhibit (10)].
(24)		**Power of Attorney**
24.1		Power of Attorney (filed herewith).
(31)		**Rule 13a-14(a)/15d-14(a) Certifications**
31.1		Certification of Chief Executive Officer of Portland General Electric Company (filed herewith).
31.2		Certification of Chief Financial Officer of Portland General Electric Company (filed herewith).
(32)		**Section 1350 Certifications**
32		Certifications of Chief Executive Officer and Chief Financial Officer of Portland General Electric Company Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).

*** Incorporated by reference as indicated.**

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

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

EXHIBIT 31.1

CERTIFICATION OF
CHIEF EXECUTIVE OFFICER
OF PORTLAND GENERAL ELECTRIC COMPANY

I, Peggy Y. Fowler, certify that:

1. I have reviewed this Annual Report on Form 10-K of Portland General Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

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

   (c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

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

Date: March 15, 2006

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

EXHIBIT 31.2

CERTIFICATION OF
CHIEF FINANCIAL OFFICER
OF PORTLAND GENERAL ELECTRIC COMPANY

I, James J. Piro, certify that:

1. I have reviewed this Annual Report on Form 10-K of Portland General Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

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

   (c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

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

Date: March 15, 2006

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

EXHIBIT 32

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

We, Peggy Y. Fowler, Chief Executive Officer and President, and James J. Piro, Executive Vice President, Finance, Chief Financial Officer and Treasurer of Portland General Electric Company (the "Company"), hereby certify that the Company's Annual Report on Form 10-K for the year ended December 31, 2005, as filed with the Securities and Exchange Commission on the date hereof pursuant to Section 13(a) of the Securities Exchange Act of 1934 (the "Report"), fully complies with the requirements of that section.

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

/s/ Peggy Y. Fowler	/s/ James J. Piro
Peggy Y. Fowler	James J. Piro
Chief Executive Officer and President	Executive Vice President, Finance, Chief Financial Officer and Treasurer
Date: March 15, 2006	Date: March 15, 2006