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, 2004**
		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 (State or other jurisdiction of incorporation or organization)	**93-0256820** (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 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 an accelerated filer (as defined in Rule 12b-2 of the 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, 2005: 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 consolidated 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
COBRA	Consolidated Omnibus Budget Reconciliation Act
Colstrip	Colstrip Units 3 and 4 Coal Plant
Coyote Springs	Coyote Springs Unit 1 Generating Plant
CUB	Citizens' Utility Board
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
Enron	Enron Corp., as Debtor and Debtor in Possession in Chapter
	11, Case No. 01-16034 pending in the United States Bankruptcy Court for the Southern District of New York
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 Company
	Electric Company included in Part II, Item 8 of this report
IRS	Internal Revenue Service
kWh	Kilowatt-hour
MW	Megawatt
MWa	Average megawatts
MWh	Megawatt-hour
NRC	Nuclear Regulatory Commission
NW Natural	Northwest Natural Gas Company
NYMEX	New York Mercantile Exchange
OPUC or the Commission	Public Utility Commission of Oregon
PBGC	Pension Benefit Guaranty Corporation
PGE or the Company	Portland General Electric Company

PUHCA		Public Utility Holding Company Act of 1935
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 2004 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 2004, and at December 31, 2004 served approximately 767,000 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."

On November 18, 2003, Enron and Oregon Electric Utility Company, LLC (Oregon Electric), a newly-formed Oregon limited liability company financially backed primarily by investment funds managed by Texas Pacific Group, entered into a definitive agreement under which Enron will sell all of the issued and outstanding common stock of PGE to Oregon Electric. The transaction, which was approved on February 5, 2004 by the Bankruptcy Court in Enron's Chapter 11 bankruptcy proceedings, requires approval of the OPUC, the FERC, the SEC, and certain other regulatory agencies. On March 10, 2005, the OPUC issued Order No. 05-114, in which it denied Oregon Electric's application to purchase PGE. Enron and Oregon Electric have stated that they are carefully reviewing the Order and evaluating their next steps. For further information, see "Enron Bankruptcy - Proposed Sale of PGE" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

As of December 31, 2004, PGE had 2,644 employees. This compares to 2,687 and 2,757 employees at December 31, 2003 and 2002, respectively. A total of 858 employees are covered under agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 841 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 2004, PGE served 251 large 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 12% of total retail revenues, they represent 11 different commercial and industrial groups, including paper manufacturing, high technology, metal fabrication, food and retail merchandising, health services, and governmental agencies. No single customer represents more than 4% of PGE's total retail load or 3.1% of total retail revenues.

Total retail revenues and MWh energy sales decreased from 2003, reflecting the effect of those customers that began purchasing energy from ESSs in 2004. PGE continues to serve these customers by delivering the energy purchased from ESSs. 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)

Non-trading wholesale electricity sales related to activities to serve retail load requirements comprised about 7% and 22% of total operating revenues in 2004 and 2003, respectively. Non-trading wholesale revenues and energy sales exclude $296 million and 6,802 thousand MWhs for 2004 and $90 million and 2,116 thousand MWhs for 2003, reflecting the October 1, 2003 adoption, on a prospective basis, of Emerging Issues Task Force No. 03-11 (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 in Purchased Power and Fuel expense. Such activities were formerly recorded on a "gross" basis in both Operating Revenues and Purchased Power and Fuel expense. For furthe r information, see Note 1, Summary of Significant Accounting Policies, in the Notes to Financial Statements.

Most of PGE's non-trading wholesale sales are to utilities and power marketers and are predominantly short-term. 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. 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.

Other Operating Revenues

Other operating revenues include net gains and losses from PGE's participation in energy trading activities in electricity and natural gas markets. Such activities are not reflected in the Company's retail prices. Also included are sales of natural gas in excess of generating plant requirements, and revenues from transmission services, pole contact rentals, and certain other electric services to customers.

The following table summarizes total Operating Revenues and Energy Sales for the year ended December 31:

		2004		2003		2002	
		Amount	%	Amount	%	Amount	%
Operating Revenues (Millions)							
	Residential	$ 585	46%	$ 555	43%	$ 567	41%
	Commercial[(a)]	504	40%	500	39%	550	40%
	Industrial[(a)]	181	14%	228	18%	269	19%
	Tariff Revenues	1,270	100%	1,283	100%	1,386	100%
	Accrued (Collected) Revenues	48		45		82	
	Retail	1,318		1,328		1,468	
	Wholesale (Non-Trading) [(b)]	107		393		391	
	Other Operating Revenues:						
	Trading Activities - net	1		2		(1)	
	Other	28		29		(3)	
	Total Operating Revenues	$1,454		$1,752		$1,855	
Energy Sales (Thousands of MWhs)							
	Residential	7,270	41%	7,099	39%	7,058	38%
	Commercial	7,247	41%	7,190	39%	7,101	38%
	Industrial	3,247	18%	4,137	22%	4,612	24%
	Retail	17,764	100%	18,426	100%	18,771	100%
	Wholesale (Non-Trading) [(b)]	2,539		9,966		12,645	
	Total Energy Sales	20,303		28,392		31,416	

(a) Retail revenues for 2004 includes $7 million for distribution services related to delivery of 776 thousand MWhs (not included in Energy Sales) to customers of ESSs, with $2 million (159 thousand MWhs) related to Commercial customers and $5 million (617 thousand MWhs) related to Industrial customers. 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.

(b) Wholesale (Non-Trading) revenues and energy sales indicated above exclude $296 million and 6,802 thousand MWhs for 2004 and $90 million and 2,116 thousand MWhs for 2003, reflecting the net basis presentation required by EITF 03-11, which became effective on October 1, 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 ensures 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.

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. PGE's License Termination Plan, approved by the NRC, outlines the process by which PGE will complete the decommissioning of the Trojan site and meet regulatory requirements for decommissioned nuclear facilities. 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. In December 2004, upon completion of final radiological surveys, PGE requested NRC termination of the Trojan Nuclear Plant Facility Operating License, which will remove the plant facility and site from regulation. Spent fuel storage activ ities will continue to be subject to NRC regulation until the storage installation is fully decommissioned, all nuclear fuel is removed from the site, and decontamination is completed. 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."

Public Utility Holding Company Act of 1935

All of the common stock of PGE is owned by Enron. As the owner of PGE's common stock, Enron is a holding company for purposes of PUHCA. Following Enron's acquisition of PGE in 1997, Enron annually filed for an exemption from all provisions of PUHCA (except Section 9(a)(2) thereof). Due to Enron's bankruptcy filing in December 2001, Enron could not provide necessary financial information required for the exemption requested. As a result, in February 2002, Enron filed an application seeking exemption under Section 3(a)(1). To be eligible for such exemption, PUHCA requires, among other things, that PGE's utility activities be predominantly intrastate in character. In December 2003, the SEC denied Enron's PUHCA exemption application under Section 3(a)(1), holding that PGE's utility activities were not predominantly and substantially intrastate in character. On March 9, 2004, Enron registered as a holding company under PUHCA.

Immediately after Enron registered, the SEC issued two orders, one granting Enron and its subsidiaries authority to undertake certain transactions without further authorization from the SEC under PUHCA (Omnibus Order) and the other approving Enron's Fifth Amended Bankruptcy Plan, except the sale of PGE to Oregon Electric, which sale will require additional approval from the SEC. Enron has filed an application, which is pending, with the SEC for approval of the proposed sale of PGE to Oregon Electric.

The Omnibus Order authorizes, among other items, certain transactions specific to PGE and its subsidiaries, including authority for PGE to issue certain short-term debt. In addition, the Omnibus Order authorizes PGE to continue providing cash management services to its subsidiaries and participate in certain transactions among associate companies within Enron's registered holding company system. The authorizations are effective until the earlier of the deregistration of Enron under PUHCA or July 31, 2005. The authority granted to PGE and its subsidiaries in the Omnibus Order minimizes the likelihood that PGE's business will be adversely impacted by Enron's registration under PUHCA.

PUHCA imposes a number of restrictions on the operations of a registered holding company and its subsidiaries within the registered holding company system. As a subsidiary of a registered holding company, PGE is subject to regulation by the SEC with respect to the acquisition of the securities of other public utilities; the acquisition of assets and interests in any other business; the declaration and payment of certain cash distributions; intra-system borrowings or indemnifications; sales, services or construction transactions with other holding company system companies; and the issuance of debt or equity securities, among other matters. To the extent those regulated activities are not approved under the Omnibus Order or otherwise exempt under various rules and the regulations promulgated under PUHCA, PGE would be required to seek additional approvals from the SEC.

Should Oregon Electric receive the regulatory approvals to acquire PGE, Oregon Electric will attempt to qualify for an exemption under Section 3(a)(1) of PUHCA. To qualify, PGE is proposing to restructure certain of its wholesale energy procurement activities. The restructuring involves the creation of a wholly-owned subsidiary of PGE that will separately engage in wholesale term trading on behalf of PGE, solely for PGE's regulated, retail electric service. Because a substantial amount of PGE's wholesale sales occur in the forward term markets, the intention of transferring this activity to a subsidiary is to allow PGE's retail and wholesale energy activities, viewed on a stand-alone basis, to qualify as predominantly intrastate in character. The proposed restructuring has been presented to and is being addressed by the OPUC, the FERC, and the SEC. There can be no assurance that the regulatory approvals required for the proposed restructuring will be obtained.

For further information, see "Enron Bankruptcy - Proposed Sale of PGE" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

Regulatory Matters

Retail Customer Choice Program

Oregon implemented a partial electric customer choice program on March 1, 2002. It provides all commercial and industrial customers of the two large investor-owned utilities in Oregon direct access to competing ESSs, as well as cost-of-service and market price options. 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. It further provides for a "transition adjustment" for non-residential customers that choose to purchase energy at market prices from investor-owned utilities or from ESS's. 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 2004, there were four ESSs registered to transact business with PGE, with two serving a total of seven customers with an average load of approximately 86 MWa, about 6% of PGE's non-residential load. In early-2005, there are three registered ESS's that are expected to serve a total of 22 customers with a load of approximately 140 MWa, about 10% of PGE's non-residential load. In addition, a total of 46 commercial and industrial customers were receiving service from PGE under market-based pricing options at the end of 2004. Approximately 34,000 customers have chosen renewable energy options and approximately 2,000 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 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 law and an order from the OPUC, PGE is deferring certain costs related to implementation of the restructuring plan for recovery in electricity prices. Recovery of these costs has begun, with unrecovered costs totaling approximately $20 million at December 31, 2004. The OPUC staff has completed an audit and prudency review of such costs and issued a report finding them to be prudently incurred.

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. During most of 2004, PGE operated under a one-year cost-based cap under terms of a 2003 settlement agreement related to prior year trading activities; the Company's market-based rate authorization was fully re-instated on December 19, 2004.

In April 2004, the FERC issued an order that requires utilities to file, on a triennial basis, for reauthorization to sell wholesale power at market-based rates. In February 2005, PGE filed a request covering the period 2005-2007, including an updated study utilizing criteria outlined by the FERC in its order. PGE anticipates reauthorization of the Company's market-based rate authority.

In response to changes in gas and electric industries, and in order to encourage competitive markets, the FERC in 2003 adopted Order 2004, Standards of Conduct, that apply uniformly to natural gas pipelines and public utilities that own transmission. The Standards of Conduct govern the relationship between transmission providers and their energy affiliates, ensuring that transmission providers do not offer preferential access to transmission capacity or non-public transmission information to their sales and marketing and energy affiliates. Order 2004 (and subsequent orders on rehearing and clarification) require that all transmission providers comply and post procedures on their Open Access Same-Time Information Systems (OASIS) so that customers and the FERC can monitor compliance by transmission providers with Standards of Conduct requirements. FERC is currently auditing all transmission providers over an approximate three-year period, during which time PGE expects to be audited.

The FERC is also currently addressing reliability issues, both in response to major regional electricity failures and to assure a high-quality electric grid. The FERC is coordinating with the North American Electric Reliability Council (NERC) in these efforts. PGE anticipates a review by the NERC in 2005.

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, 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 September 2002, the formation plan of RTO West received preliminary approval of the FERC. Although the FERC indicated that the RTO West proposal would satisfy requirements of Order No. 2000, RTO West did not attain broad regional support. Renewed efforts and further assessment of transmission problems and opportunities by regional representatives resulted in a proposal to restructure RTO West as an independent, non-profit corporation managing certain operational functions of the regional transmission grid in Oregon, Washington, Idaho, Montana, Nevada, Utah, and Wyoming. It is also designed to facilitate participation of British Columbia transmission providers. In March 2004, RTO West was renamed Grid West.

The Grid West proposal 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 many of the operating functions that affect use of regional transmission facilities would be managed by the new, independent organization, ownership of transmission facilities would not change and existing transmission rights would be retained. Grid West would be financially independent from electric utilities or suppliers that rely on it for transmission service and would be governed by an independent board selected by regional member representatives. In December 2004, PGE and eight other transmission providers (including BPA) adopted bylaws that would govern Grid West. Further development of Grid West will be determined in late-2005, based upon decisions by transmission providers to provide full financial support. If such support is prov ided, formation of a developmental board of trustees will proceed, with operations planned to begin in 2007.

Retail Rate Changes

PGE's most recent general rate filing authorized retail price increases 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 2003, 2004, and 2005. The OPUC also approved power cost adjustment mechanisms covering the years 2001 and 2002. As actual power costs during those years exceeded projected costs used in rate determination, the mechanisms allowed the Company to defer for later recovery from retail customers actual net variable power costs in excess of certain baseline amounts. PGE did not have a power cost adjustment mechanism in place for 2003 or 2004. For further information, see "Resource Valuation Mechanism" and "Power Cost Adjustment Mechanisms" 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, long-term price stability, and cost effectiveness. Planning for future resources is guided by PGE's objective to balance its load requirements with its generating resources and mid- to long-term power contracts. As part of the Company's resource planning process, PGE in 2003 issued a request for proposals (RFP) to prospective suppliers (including power generators, wholesalers, and developers) to acquire resources to meet the electricity needs of its customers. In March 2004, PGE filed its Integrated Resource Final Action Plan with the Commission on how to best meet its customers' future power supply requirements. Recommendations included the acquisition of approximately 790 MWa in short-term, mid-term, and long-term resources, consisting of six components: 1) construction of a natural gas-fired power plant at PGE's Port Westward site in Columbia County, Oregon, producing 350 MWa, beginning in mid-2007; 2) acquisition of 65 MWa (195 MW capacity) of wind generation from RFP proposals; 3) acquisition of 135 MWa in fixed price power purchase agreements with durations of 5 to 10 years from RFP proposals; 4) acquisition of 55 MWa in energy efficiency savings by the Energy Trust of Oregon; 5) upgrades and contract extensions to existing plants of 60 MWa; and, 6) short-term market acquisitions of 125 MWa. In addition to the increased capacity, the recommendations include approximately 955 MW of additional capacity from the extension of a current contract with the Confederated Tribes of the Warm Springs Reservation of Oregon to 2012, 400 MW of tolling capability for peaking purposes, 30 MW of dispatchable standby generation, and 25 MW of capacity from duct firing capability at Port Westward.

In July 2004, the OPUC issued an order acknowledging PGE's Final Action Plan. The order includes requirements that PGE address constraints on competitive renewable development in the region, 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 before issuing its next RFP. The OPUC waived certain Oregon administrative rules to allow cost-based treatment of capital, operation and maintenance costs of Port Westward.

PGE's acquisitions under the RFP process include a ten-year power purchase agreement for 85 MWa, beginning in late 2006, a thirty-year purchase power agreement for 27 MWa of wind generated power, beginning in late 2005, and two five-year agreements, consisting of a power purchase option for 14 MWa 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.

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 accommodating 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 that compete primarily for residential space heating customers. In addition, effective March 1, 2002, 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. 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

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. PGE will continue its participation 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 Company currently has authority under its FERC tariff to charge market-based rates for wholesale energy sales. For most of 2004, the Company operated under a one-year cost-based cap pursuant to terms of a 2003 settlement agreement between PGE, th e FERC, and other parties related to trading activities by PGE during the California energy crisis in 2000-2001.

The Northwest transmission system connects winter-peaking utilities in the Northwest and summer-peaking wholesale customers in California and the Southwest. PGE uses this interconnected transmission system to purchase and sell in both markets depending upon the relative price and availability of power, water conditions, and seasonal demand from each market.

Public Ownership Initiatives

In addition to the potential loss of energy related revenues from those commercial and industrial customers that may choose to purchase energy directly from competing energy suppliers, there is the potential for the loss of service territory from the creation of people's utility districts or municipal utilities in PGE's service territory. For further information, see "Public Ownership Initiatives" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

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 continued below-normal hydro conditions in 2005. In addition, natural gas and coal, used to fuel the Company's thermal generating plants, are subject to price volatility. PGE continues to monitor its exposure to natural gas and coal.

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

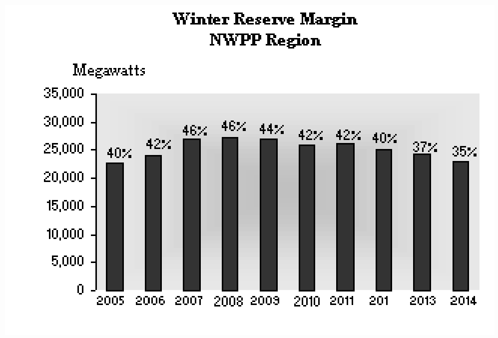
PGE's existing hydroelectric, coal-fired, and gas-fired plants are important resources for the Company, providing 1,975 MW of generating capability (see Item 2. - "Properties" for a full listing of PGE's generating facilities). The Company's lowest cost generating resources are its five FERC licensed hydroelectric projects that incorporate eight powerhouses on the Clackamas, Sandy, Deschutes, and Willamette rivers in Oregon. These facilities operate under federal licenses, which will be up for renewal through 2006. PGE will not relicense its 22 MW Bull Run hydroelectric project on the Sandy River.

PGE's Integrated Resource Final Action Plan, acknowledged by the OPUC in July 2004, includes the acquisition of approximately 790 MWa in additional power resources. Construction of a 350 MWa natural gas-fired plant at the Company's Port Westward site began in February 2005, with completion expected by mid-2007. Additional recommended resource acquisitions include wind generation, fixed price power purchase agreements, energy efficiency savings, upgrades and contract extensions of existing plants, and short-term market acquisitions.

Purchased Power

PGE supplements its own generation with long-term and short-term 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 510 MW of firm capacity. PGE also has firm contracts, ranging from one to twenty-five years, to purchase 738 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, beginning 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 a Northwest utility to help meet the Company's summer-peaking requirements. These resources, along with short-term contracts, provide the Company wi th 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 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 approxi mately 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, peak demand and annual energy requirements in the NWPP through 2013 are projected to grow at annual rates of 2.0% and 1.6%, 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 35% to 46% of winter peak demand, as indicated in the above table.

PGE's peak load in 2004 was 3,942 MW, of which approximately 48% was met through short-term purchases. At December 31, 2004, PGE's total firm resource capacity, including short-term purchase agreements, was approximately 3,941 MW (net of short-term sales agreements of 1,106 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 either been granted, or are being evaluated for, protection under the federal Endangered Species Act (ESA), which was initially enacted in 1966. Passage of the ESA, and the subsequent listing of various species of fish, wildlife, and plants as threatened or endangered species, has resulted in potentially 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 (USFWS) has identified opportunities for the protection of fish runs on those rivers where PGE operates. The agencies have completed ESA consultations on the Company's Pelton Round Butte Project (Deschutes River) and Clackamas River project, which will be in effect until new licenses are granted by the FERC. In 2003, the Company received the Biological Opinion for the Bull Run Project (Sandy River) which will cover the project's operations and decommissioning.

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. PGE anticipates the completion of several ESA consultations in 2005, with the Willamette Falls Project (Willamette River) and the Pelton Round Butte Project (Deschutes River) expected to receive new FERC operating licenses with the associated Biological Opinion and Incidental Take Statement. PGE does not anticipate significant changes in the terms and conditions required to minimize take of ESA-protected species in the Company's new FERC licenses.

In conjunction with the relicensing application for the Pelton Round Butte hydro project, a settlement agreement was completed and signed by all participants in July 2004 and submitted to the FERC for approval. The agreement includes a recommendation that the FERC issue a 50-year license for the project and also includes provisions for fish passage over the project's dams. Approval by the FERC is expected by mid-2005.

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 2005. 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 2004, totaling about 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 provides for coal to not exceed a maximum sulfur content of 1.5% by weight. 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. In 2003, PGE was 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

Firm gas supplies for Beaver, based on anticipated operation of the plant, are typically purchased up to 24 months in advance. PGE has access to 76,000 Dth/day of firm transportation capacity, sufficient to operate the plant at a 70% load factor. The Company has also acquired 11,000 Dth/day of firm transportation capacity that can be used at Beaver until Port Westward becomes operational (see below). In addition, PGE has contractual access, through October 2005, to natural gas storage in Mist, Oregon, from which it can draw natural gas in the event the plant's supply is interrupted or if economic factors require its use. The Company also has contractual access, through November 2005, to 20,000 Dth/day of transportation capacity from a pipeline connection to a natural gas production area in British Columbia, Canada. PGE believes that sufficient market supplies of gas are available to fully meet anticipated requirements of Beaver in 2005.

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 2005.

Port Westward

PGE has acquired 11,000 Dth/day of firm transportation capacity for use at Port Westward when it begins operations, currently planned for May 2007. Until the plant becomes operational, such capacity is available either for use at Beaver or for remarketing to others. The contract, which extends through March 2008 and contains ongoing renewal rights, became effective in November 2004. PGE also plans to acquire back-up gas storage capacity closer to the operational date of Port Westward.

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 15-day supply of oil at the plant site at December 31, 2004.

Coyote Springs

The Coyote Springs plant has the capability to operate on oil if needed, with sufficient fuel maintained on-site to run the plant for 40-50 hours.

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 Office 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, including PGE. Management believes that the Company's contribution to the sediment contamination, if any, would qualify it as a de minimis Potentially Responsible Party.

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

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.

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 guidelines 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 without the need to purchase additional emissions allowances.

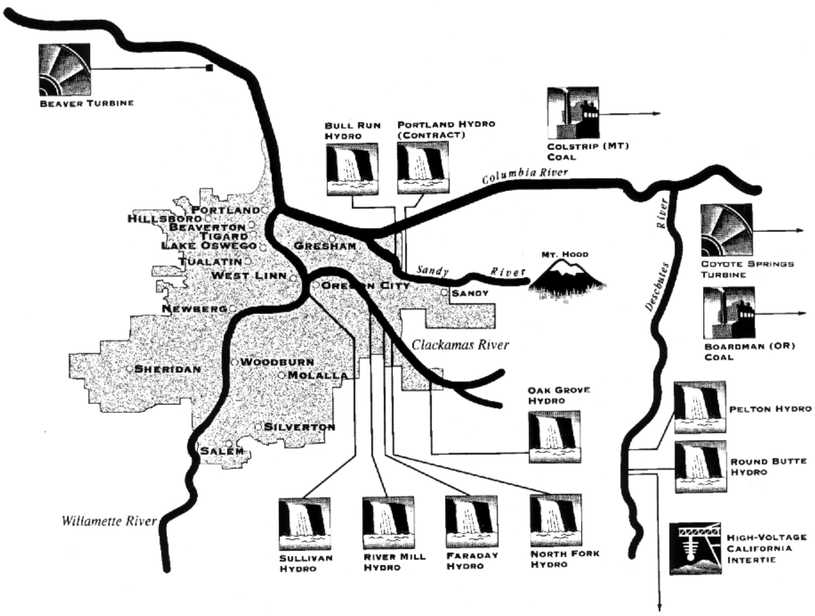
PGE has a 20% ownership interest in Colstrip Units 3 and 4, which is operated by PPL Montana, LLC (PPL Montana). PPL Montana and the EPA are discussing possible emission control and monitoring requirements involving all Colstrip units that address certain issues that have arisen since late 2003, including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

It is not yet known what impacts federal regulations on mercury transport, regional haze, or particulate matter standards may have on future operations, operating costs, or generating capacity of Boardman and Colstrip. For further information, see "Environmental Matters" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

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

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, 2004 (*)	
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	245	
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			1,975	

(*) 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.

Hydro Relicensing

PGE holds licenses under the Federal Power Act for its hydroelectric generating plants, as well as licenses from the State of Oregon for all or portions of the five projects.

The Company filed a 30-year license application with the FERC in December 2002 for its 16 MW Willamette River project, the current license for which expired on December 31, 2004. In 2003, the Company and participants in the relicensing process completed a settlement process that resulted in an agreement that was filed with the FERC in January 2004. 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 federal agencies responsible for salmon protection and ESA issues were participants in the settlement process. A decision from the FERC is expected in 2005.

The license for the Clackamas River projects expires in 2006. PGE filed a license application with the FERC in 2004 and anticipates completion of the settlement process and an agreement among all parties in 2005.

The license for the Pelton Round Butte project expired at the end of 2001, with the project operating on annual licenses since that time. In June 2001, PGE and the Confederated Tribes of the Warm Springs Reservation of Oregon jointly filed a 50-year license application. Participants in the relicensing process have completed settlement negotiations and filed an agreement with the FERC in July 2004 on the proposed terms and conditions of the new license. Approval of the license application by the FERC is expected by mid-2005.

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's current prices include recovery of its remaining plant investment through June 30, 2005 and recovery, over a ten-year period beginning October 2001, of about $16 million in estimated decommissioning costs.

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.

Generating Capability Changes

PGE's share of the generating capability at Boardman increased by 18 MW in 2004 due to an upgrade to the turbine rotor.

Leased Properties

PGE leases its Portland headquarters complex and the coal-handling facilities at the Boardman plant.

Item 3. Legal Proceedings

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

Following the closing of Trojan, PGE, in its 1993 general rate filing, sought OPUC approval to recover through rates future decommissioning costs and full recovery of, and a rate of return on, its Trojan investment. PGE's request was challenged and PGE requested from the OPUC a Declaratory Ruling (Docket DR 10) regarding recovery of the Trojan investment and decommissioning costs. In August 1993, the OPUC issued a Declaratory Ruling in PGE's favor, citing an opinion issued by the Oregon Department of Justice (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 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 August 31, 2004 Order.

On December 20, 2004, the URP and Class Action Plaintiffs (see Dreyer case below) filed an application with the OPUC for reconsideration of the OPUC's October 18, 2004 Order. On February 11, 2005, the OPUC denied reconsideration.

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.

David Kafoury, an individual, and Kafoury Brothers, LLC, an Oregon Limited Liability Corporation, each as representative of class, etc. v. Portland General Electric Company, 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.

Gordon v. Reliant Energy, Inc./Duke Energy Trading and Marketing, et al v. Arizona Public Service Company, et al, Superior Court of the State of California for the County of San Diego, Proceeding Nos. 4204 and 4205. In re Wholesale Electricity Antitrust Cases I & II, USDC Southern District of California, Case Nos. CV02-990, 1000, 1001; USCA Ninth Circuit Court of Appeals, Case No. 02-57200, et al.

On December 24, 2001, numerous individuals, businesses, and California cities, counties, and other governmental entities filed a consolidated Master Complaint in their class action law suits (Wholesale Electricity Antitrust Cases) in California state court against various individuals, utilities, generators, traders, and other entities, including Duke Energy Trading and Marketing, LLC; Duke Energy Morro Bay, LLC; Duke Energy Moss Landing, LLC; Duke Energy South Bay, LLC and Duke Energy Oakland, LLC (Duke Parties), and Reliant Energy Services, Inc., Reliant Ormond Beach, Inc., Reliant Energy Etiwanda, Inc., Reliant Energy Ellwood, Inc., Reliant Energy Mandalay, Inc., and Reliant Energy Coolwater, Inc. (Reliant Parties), alleging that activities related to the purchase and sale of electricity in California in 2000 and 2001 violated California antitrust and unfair competition laws. The complaint seeks, among other things, restitution of all funds acquired by means that violate the law and payment of treble damages, interest, and penalties.

On April 23, 2002, the Duke Parties filed a cross complaint against PGE and other utilities, generators, traders and other entities not named in the Wholesale Electricity Antitrust Cases (Cross-defendants), alleging that they participated in the purchase and sale of electricity in California during 2000-2001 and seeking complete indemnification and/or partial equitable indemnity on a comparative fault basis for any liability that the Court may impose on the Duke Parties under the Wholesale Electricity Antitrust Cases. Legal and equitable relief is sought, with no specific monetary amount claimed. The Reliant Parties have filed a similar cross complaint against PGE and the other Cross-defendants. The cases were removed to Federal Court by certain parties. The Duke Parties, Reliant Parties, and Cross-defendants have stipulated to place the cross complaints in abeyance until 30 days after a ruling on their motions to dismiss the Master Complaint by either the California state courts or the fe deral courts.

On December 13, 2002, the United States District Court signed an order granting the plaintiff's motions to remand the cases to the California state court. The Duke and Reliant Parties filed an appeal to the United States Ninth Circuit Court of Appeals. On February 20, 2003, the United States Court of Appeals for the Ninth Circuit issued an Order deciding it had jurisdiction to hear the appeals from the District Court's December 13, 2002 remand order. The Ninth Circuit also issued a stay of the remand order pending the outcome of the appeals. The Ninth Circuit issued its opinion affirming the District Court's order on remand on December 8, 2004, but ordered the District Court to dismiss the federal defendants. PGE is not one of those defendants.

As stated above, the cross complaint against PGE will be continued in abeyance until 30 days after a ruling is entered on the Reliant and Duke Parties' motions to dismiss the Master Complaint.

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. 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 fe es. On December 4, 2003, this case was transferred to the Southern District of California for consolidation with the Wholesale Electricity Antitrust Cases I and II (Case No. CV02-990, 1000, 1001) discussed above.

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.

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

On June 30, 2003, the Montana Attorney General filed a complaint in Montana state court against PGE and numerous named and unnamed generators, suppliers, traders, and marketers of electricity and natural gas in Montana. The Complaint alleges unfair and deceptive trade practices in violation of the Montana Unfair Trade and Practices and Consumer Protection Act, deception, fraud and intentional infliction of harm arising from various actions alleged to have been undertaken in the western wholesale electricity and natural gas markets during 2000 and 2001. The relief sought includes injunctive relief to prohibit the unlawful practices alleged, treble damages, general damages, interest, and attorney fees. No monetary amount is specified. The case was removed to 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 see ks 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.

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 $175,000,000. 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.

Portland General Electric Company v. Hardy Meyers, In His Official Capacity as Attorney General of the State of Oregon, United States District Court for the District of Oregon, Case No. 03-1641-HA, and State of Oregon, ex rel Hardy Meyers, Attorney General for the State of Oregon v. Portland General Electric Company, Multnomah County Oregon Circuit Court, Case No. 0312-13473

On November 26, 2003, PGE filed a complaint for Declaratory Relief in U.S. District Court for the District of Oregon seeking to end the Oregon Attorney General's investigation into the Company's participation in wholesale power trading markets related to the California energy crisis of 2000-2001. The complaint is based on Federal preemption grounds and judicial estoppel because the State of Oregon, through the OPUC, has settled with the Company on these issues.

On December 16, 2003, the Oregon Attorney General filed in the Multnomah County Oregon Circuit Court a Motion for Order to Show Cause why the Company should not comply with the Oregon Attorney General's investigation. The motion was removed to the U.S. District Court for the District of Oregon, and the same District Court Judge was assigned to both cases. On July 30, 2004 the District Court Judge dismissed the PGE Case without prejudice on the basis that the case is not ripe for review, and remanded the Attorney General Case to the Multnomah County Oregon Circuit Court on the basis that the state investigation is not a civil case over which the U.S. District Court has jurisdiction.

On August 18, 2004, PGE appealed the ruling on the PGE Case to the United States Ninth Circuit Court of Appeals.

On September 3, 2004, the Multnomah County Oregon Circuit Court ruled in favor of the Attorney General, but, on September 13, 2004, granted PGE's motion to stay enforcement of the decision for 90 days. On September 10, 2004, PGE appealed the Multnomah County Court decision in favor of the Attorney General to the Oregon Court of Appeals. On September 30, 2004, PGE filed a motion with the Oregon Court of Appeals for an expedited appeal and an extension of the stay. On October 19, 2004 the Oregon Court of Appeals granted PGE's motions. On November 2, 2004, the Oregon Attorney General filed a Motion for Reconsideration, which was denied on January 25, 2005.

Robert and Julie Remington, 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, Silver Bow County, Case No. DV 03-88

On May 5, 2003, Robert and Julie Remington and forty-eight other individuals, 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.

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 ag ainst 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.

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

None.

Part II

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

Equity Securities

PGE is a wholly owned subsidiary of Enron, which owns all 42,758,877 shares of PGE's outstanding common stock. No cash dividends were declared on common stock during 2003 or 2004.

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). In addition, the terms of PGE's two revolving credit facilities provide for payment of dividends not to exceed $240 million and, beginning on January 1, 2005, permit the payment of additional dividends in an aggregate amount not exceeding PGE's cumulative net income for each quarterly period. If the proposed purchase of PGE by Oregon Electric closes, PGE anticipates it will declare and pay a common stock dividend to Oregon Electric in the range of $250 million to $280 million in early 2005. On March 10, 2005, the OPUC issued Order No. 05-114, in which it denied Oregon Electric's application to purchase PGE. Oregon Electric has stated that it is carefully reviewing the Order and evaluating its next steps.

Item 6. Selected Financial Data

	For the Years Ended December 31				
	2004	2003	2002	2001	2000
	(In Millions)				
Operating Revenues (a)	$1,454	$1,752	$1,855	$2,420	$1,887
Net Operating Income	150	124	135	134	206
Net Income	92	58	66	34	141
Total Assets (b)	3,403	3,372	3,455	3,622	3,566
Long-Term Debt (c)	922	983	1,046	972	880

(a) Operating Revenues for 2004 and 2003 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 2004 and 2003 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) Amounts for 2000 through 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.

(c) 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 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.

Economy - PGE's business, like most utilities, is affected by the general economy and by population growth in its service territory. The Company continues to experience customer growth, adding approximately 48,000 retail customers in the last five years (including 13,000 in 2004), and now serves over 767,000 customers as the largest supplier of electricity in the state. The Company's diverse retail customer base has helped mitigate the effects of a three-year slowdown in Oregon's economy. The state's economy rebounded in 2004, adding nearly 45,000 jobs (including 6,200 in manufacturing) during the year, resulting in an approximate 2.8% increase in total payroll. The seasonally-adjusted unemployment rate has fallen from a high of 8.7% in July 2003 to 7.6% at year-end 2003 to 6.8% at year-end 2004.

Residential and commercial energy sales in 2004 reflect continued customer growth and the improved economy. Gains in these two sectors partially offset a reduction in industrial energy sales resulting from the decision of certain customers to purchase their energy from ESSs, as allowed under Oregon's electricity restructuring law. Weather adjusted retail energy deliveries to PGE and ESS customers are expected to increase by approximately 2% in 2005.

PGE continues to play an active role in supporting economic growth and business development in the region. Such efforts promote job creation and load growth, and encourage retention and expansion actions of the Company's major customers. Recently, PGE has worked closely in a public/private cooperative effort, led by Oregon's governor, the state's two Senators, and key business leaders. Termed the "Oregon Plan," it is intended to serve as the foundation of the state's economic development initiatives, with recent focus on identification of new project-ready industrial sites. These efforts have resulted in an increase in the number of businesses planning to expand or locate operations within PGE's service territory.

Operations - PGE continues to serve its customers effectively and operate well. Despite the effects of poor regional hydro conditions, the lack of a power cost adjustment mechanism, and an extended maintenance outage at the Boardman coal plant, PGE's earnings in 2004 were more typical of the Company's historical levels than in recent years. An improved local economy, higher margins on energy sales, and the reduced negative impact of Enron's bankruptcy and events related to the 2000-2001 West Coast energy crisis contributed to earnings in 2004 that exceeded each of the three preceding years. Although energy sales continue to run below levels projected in PGE's most recent general rate case, and the Company is not achieving its allowed rate of return on equity, PGE continues to maintain a strong financial position, with investment-grade ratings on its secured debt, adequate liquidity, and stable operating cash flow. These factors have enabled PGE to effectively invest in its systems, acquire and plan for new power supply resources, and improve operational efficiency.

PGE continues to meet regulatory standards for safety and service quality related to outage frequency and duration, and the Company's customer satisfaction index remains strong among both residential and business customers, with reliability, restoration response, and customer service significant factors. PGE's response to service outages, including restoration and cleanup efforts required by a severe snow and ice storm in January 2004, continues to have a positive impact on customer satisfaction.

PGE continues to invest in its transmission and distribution systems and in additions and upgrades to its generating facilities. Decommissioning of the Company's closed Trojan nuclear plant is proceeding well, with the transfer of spent fuel to a temporary storage facility completed in 2003 and termination of the plant's facility operating license expected in 2005.

A new five-year agreement with PGE's bargaining unit employees, reached in early-2004 and extending to 2009, provides stability for both union employees and the Company. The control of employee benefit and retirement savings plans has been returned to PGE from Enron, effective for 2005. PGE and its employees continue their long-established commitment to the community through corporate support of local non-profit groups and employee volunteer efforts.

Voters in late-2003 and in 2004 rejected PUD initiatives in Multnomah, Yamhill, Clackamas, and Washington Counties, where the majority of PGE's customers reside. PGE continues to oppose the formation of PUDs in its service territory and any efforts to condemn the Company's assets.

Power Supply - PGE manages its power supply to secure reasonably priced power for customers by effectively using the Company's assets and marketing and operational expertise. PGE can meet approximately 75% of its estimated 2005 retail 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 natural gas or other thermal sources.

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.

PGE remains active in wholesale energy markets, which are integral to the Company's retail business, providing for the efficient use of its generating capacity. Wholesale energy market prices have increased in the last two years, reflecting higher natural gas prices and below-normal regional hydro conditions. The Company utilized wholesale electricity and fuel purchases, as well as its existing generating plants, to maintain a balanced net energy position through the winter peak period and the remainder of 2004.

Regional water conditions in 2004 were again below average, approximating those of 2003 and resulting in reduced generation from both PGE's hydro projects and those on the mid-Columbia River from which the Company purchases power. PGE and mid-Columbia hydro generation in the last two years averaged about 34,000 MWhs and 175,000 MWhs, respectively, lower than that of 2002, the last year of near normal hydro conditions. Regional hydro conditions, including those on both the Clackamas and Deschutes river systems where the Company's facilities are located, are projected to again be significantly below normal in 2005. This could require increased output from the Company's thermal generating plants and energy purchases in the wholesale market, which would result in increased power costs. Natural gas, used to fuel the Company's combustion turbine plants, is subject to price volatility resulting from supply issues, which can also affect generation and purchased power costs.

PGE's thermal generating plants continued to operate well in 2004, as the Company effectively utilized its generating assets and experience in the wholesale marketplace to meet load requirements and offset the adverse financial effects of poor regional hydro conditions. Efficiency upgrades to the Boardman coal plant, completed during an extended maintenance outage, increased PGE's share of the plant's generation by 18 MW (enough electricity to serve over 11,000 homes) with no additional fuel requirements.

In conjunction with a 50-year relicensing application for the Pelton Round Butte hydro project, a settlement agreement was completed and signed by all participants in July 2004 and submitted to the FERC for approval, which is expected in mid-2005.

PGE's Integrated Resource Final Action Plan, containing specific resource actions to meet the future electricity needs of customers, received formal acknowledgement by the OPUC in July 2004. The plan includes the acquisition of about 790 MWa in additional power resources, including the construction of the 350 MWa natural gas-fired Port Westward project and acquisition of about 200 MWa of renewable energy resources. In the first major step toward meeting the Company's renewable power supply goals, PGE signed a 30-year agreement for 27 MWa of wind capacity, beginning in December 2005.

The "Resource Valuation Mechanism" (RVM) process, by which retail prices are adjusted annually with changes in projected power costs, has enabled the Company to adjust customer prices on a more timely basis to reflect the variable cost of power. This process resulted in small average rate increases for 2004 and 2005. In addition, the Company has requested OPUC consideration of a Hydro Generation Adjustment tariff that would allow rate adjustments reflecting changes in power costs caused by variations in hydro conditions, and currently has a hydro cost deferral application for 2005 pending with the Commission. Decisions are expected in 2005. The Company continues to evaluate the need to align its general rate structure to sufficiently cover its operating costs.

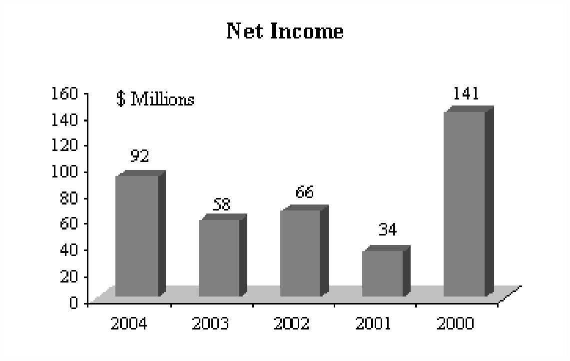
Proposed Sale of PGE - On March 10, 2005, the OPUC issued Order No. 05-114, in which it denied Oregon Electric's application to purchase PGE. Enron and Oregon Electric have stated that they are carefully reviewing the Order and evaluating their next steps. In addition to OPUC approval, Oregon Electric's purchase of PGE would require the approval of the SEC and the FERC.

Results of Operations

2004 Compared to 2003

PGE's net income in 2004 was $92 million compared to $58 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.

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, last year's 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.

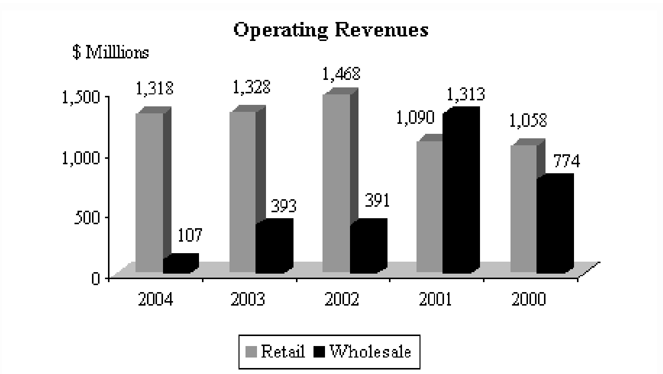


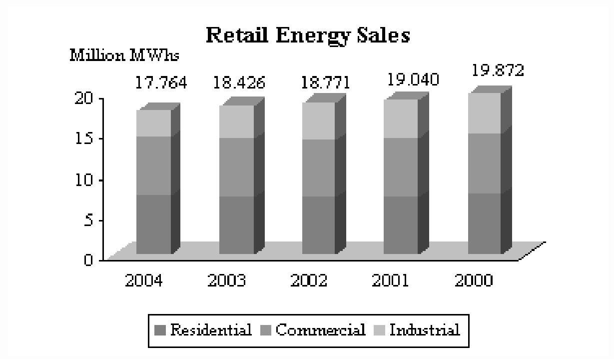
The following table summarizes Operating Revenues and Energy Sales for 2004 and 2003:

Operating Revenues	2004		2003		Increase/ (Decrease)
(In Millions)					
Retail [a]	$1,318		$1,328		$ (10)
Wholesale (Non-Trading) [b]	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 Sales					
(In Thousands of MWhs)					
Retail [a]	17,764		18,426		(662)
Wholesale (Non-Trading) [b]	2,539		9,966		(7,427)
Trading Activities	9,699		13,551		(3,852)
Total Energy Sales	30,002		41,943		(11,941)

(a) Retail revenues for 2004 includes $7 million for distribution services related to delivery of 776 thousand MWhs (not included in Energy Sales) to customers of ESSs. 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.

(b) Wholesale (Non-Trading) revenues and energy sales indicated above exclude $296 million and 6,802 thousand MWhs for 2004 and $90 million and 2,116 thousand MWhs for 2003, reflecting the net basis presentation required by EITF 03-11, which became effective (on a prospective basis) on October 1, 2003.





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 industria l 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 availabili ty.

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 d ecreased 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	34.5	35.0
Spot Purchases	1,343	2,404	42.9	38.5
Total Send-Out	21,474	29,691	31.9*	32.2*

(* includes wheeling costs)

Note: Megawatt-Hours indicated above exclude Term Purchases of 4,753 thousand MWhs and 1,907 thousand MWhs for 2004 and 2003, respectively, and Spot Purchases of 2,049 thousand MWhs and 209 thousand MWhs for 2004 and 2003, respectively, to reflect the net basis presentation required by EITF 03-11, which became effective (on a prospective basis) on October 1, 2003. For further information, see Note 1, Summary of Significant Accounting Policies, in the Notes to Financial Statements. Average Variable Power Cost amounts exclude the effect of the reductions.

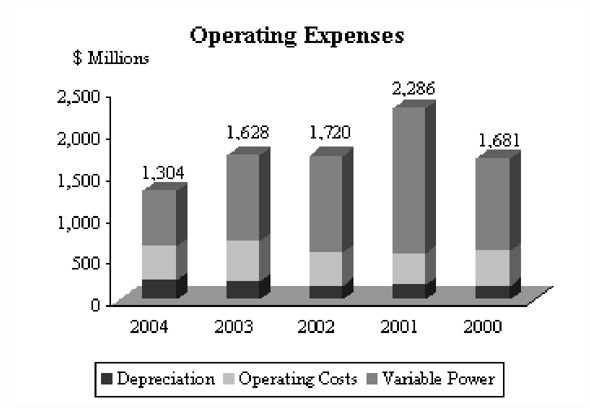
Production, distribution, administrative and other expenses increased $10 million (4%) from 2003 due primarily to costs related to an extended maintenance outage at the Boardman coal plant, increased service restoration costs (net of insurance recovery) related to a five-day snow and ice storm in January 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 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.



2003 Compared to 2002

PGE's net income in 2003 was $58 million compared to $66 million in 2002. 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. Earnings in 2003 were unfavorably impacted by poor hydro conditions and lack of a power cost adjustment mechanism. A 1.8% decline in retail energy sales, resulting primarily from warmer weather in the year's first quarter, also reduced earnings for the year. A power cost adjustment mechanism in place during 2002 partially offset the negative earnings impact of energy sales that fell 8% lower than levels used in PGE's general rate case implemented in the fourth quarter of 2001. Although Oregon's economy improved, retail energ y sales in 2003 remained approximately 8% lower than projected in the Company's rate case. Higher income from non-qualified benefit plan trust assets, a reduction in nonutility expenses, and gains on energy trading activities were offset by increased amortization and interest charges. Results for 2003 also include a $2 million gain from a cumulative effect of a change in accounting principle related to the adoption of SFAS No. 143, Accounting for Asset Retirement Obligations.

The following table summarizes Operating Revenues and Energy Sales for 2003 and 2002:

Operating Revenues	2003		2002		Increase/ (Decrease)
(In Millions)					
Retail	$1,328		$1,468		$ (140)
Wholesale (Non-Trading)	393		391		2
Other Operating Revenues:					
Trading Activities - net	2		(1)		3
Other	29		(3)		32
Total Operating Revenues	$1,752		$1,855		$ (103)
Energy Sales					
(In Thousands of MWhs)					
Retail	18,426		18,771		(345)
Wholesale (Non-Trading)	9,966		12,645		(2,679)
Trading Activities	13,551		11,292		2,259
Total Energy Sales	41,943		42,708		(765)

Note: Wholesale (Non-Trading) revenues and energy sales for 2003 exclude $90 million and 2,116 thousand MWhs, respectively, reflecting the net basis presentation required by EITF 03-11, which became effective (on a prospective basis) on October 1, 2003.

The decrease in Retail Revenues in 2003 was caused by both lower prices and energy sales. As provided in the OPUC's 2001 general rate order, PGE reduced its retail customer prices by an average of approximately 7% on January 1, 2003 to reflect a decrease in projected 2003 variable power costs (see "Resource Valuation Mechanism" in the Financial and Operating Outlook section for further information). Retail energy sales decreased from 2002 due to a 10% decline in industrial sales, most of which was attributable to a single large customer that began generating its own power requirements in the second quarter of 2003. Combined residential and commercial energy sales increased approximately 1% from 2002, as an approximate 10,600 (1.4%) increase in the number of customers served was partially offset by warmer temperatures in the first quarter of 2003 and conservation efforts. Average wholesale power prices increased 28%, reflecting higher summer temperatures as well as increased natural gas prices and adverse hydro conditions in the region. Lower wholesale 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 results 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 years' reported revenues and expenses is not practicable, the change has no impact on reported net income. The increase in Other Operating Revenues was primarily related to sales of natural gas in excess of generating plant requirements, as power purchases in the wholesale market economically displaced more expensive gas-fired thermal ge neration. Such sales in 2003 resulted in a $13 million gain, compared to an $18 million loss in 2002 caused by low natural gas prices.

Purchased Power and Fuel expense decreased $129 million (11%). The decrease was due to both a $90 million reduction resulting from the adoption of EITF 03-11 (described above) and to lower purchased power costs, attributable to lower term prices in 2002 for power delivered in 2003. Such reductions, combined with decreased fuel costs and an approximate 2% reduction in total system load, more than offset the combined effects of the discontinuance of the Company's power cost adjustment mechanism and 2003 provisions for uncollectible accounts receivable for wholesale electricity sales. Lower term power prices for power delivered in 2003 more than offset higher spot power prices during the year. Combined with a decrease in the cost of coal-fired generation, PGE's average variable power cost decreased 10% from that of 2002. Purchased Power and Fuel costs in 2003 include a $62 million charge for the amortization of costs deferred under the power cost adjustment mechanisms in 2001 and 20 02, which were recovered from customers in 2003. Purchased Power and Fuel costs in 2002 included a net credit of $13 million related to the Company's power cost adjustment mechanisms, consisting of a $36 million credit for the deferral of 2002 power costs and a $23 million charge for amortization of 2001 deferred costs recovered from customers in 2002. There was no power cost adjustment mechanism in place in 2003. Also included in 2003 are $22.5 million of provisions for uncollectible accounts receivable for wholesale electricity sales related to sales made in the California market during 2000 and 2001. (For further information, see "Receivables and Refunds on Wholesale Market Transactions" in "Financial and Operating Outlook" of this Item 7). Total Company generation increased 4% from 2002, with increased coal-fired generation partially offset by both reduced hydro production (due to low stream flows) and combustion turbine generation, resulting from the forced outage of the Coyote Springs plant during the second quarter of 2003. Total generation met approximately 40% of PGE's retail load during the year, compared to 38% in 2002, with the increase attributable to planned maintenance and economic displacement of combustion turbine generation, and planned maintenance and repair outages at the Company's coal-fired generating plants in 2002.

Due to anticipated adverse hydro conditions in the region, PGE filed an application with the OPUC seeking deferral, for future recovery from customers, of approximately $25 million in hydro replacement power costs for the period February 11, 2003 (application date) through December 31, 2003. This application was denied by the Commission in March 2004.

The following table indicates PGE's total system load (including both retail and wholesale) for the years indicated (excludes energy trading activities). Average variable power costs exclude 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)	
	2003	2002	2003	2002
Generation	7,922	7,625	15.6	17.1
Term Purchases	19,365	21,311	35.0	42.5
Spot Purchases	2,404	3,619	38.5	20.0
Total Send-Out	29,691	32,555	32.2*	35.9*

(* includes wheeling costs)

Note: Amounts indicated above for 2003 include fourth quarter reductions in Term Purchases and Spot Purchases of 1,907 thousand MWhs and 209 thousand MWhs, respectively, to reflect the presentation required by EITF 03-11, which became effective (on a prospective basis) on October 1, 2003. For further information, see Note 1, Summary of Significant Accounting Policies, in the Notes to Financial Statements.

Production, distribution, administrative and other expenses were unchanged from 2002. Increased pension and medical benefit costs were offset by a reduction in major maintenance expenses at the Company's generating plants and reduced costs related to implementation of Oregon's electricity restructuring law (fully offset within Depreciation and Amortization).

Depreciation and Amortization expense increased $52 million (32%), primarily due to decreased amortization of regulatory liabilities, the effects of which are offset within Operating Revenues. This includes $23 million in credits given to customers in 2002 related to a distribution received by PGE in 2000 from Nuclear Electric Insurance Limited. Other reductions in regulatory liabilities include a combined $17 million in credits related to merger-related cost savings and gains on certain major property sales provided to customers in 2002. Amortization of computer software, including the Company's new customer information and billing system, increased by $4 million. The remaining increase was caused by a nonrecurring $4 million credit in 2002 related to the sale of the Pelton Round Butte hydroelectric project (offset in Income taxes) and a $4 million increase related to the deferral and amortization of costs related to implementation of Oregon's electricity restructuring law.

Income taxes decreased $18 million primarily due to lower taxable income. Included in 2002 is an adjustment that increased income tax expense by $4.5 million to establish deferred income taxes related to a property tax temporary difference that was not identified at the time the Company implemented SFAS No. 109, Accounting for Income Taxes, in 1993.

Other Income increased $13 million, resulting primarily from a $10 million increase in income from non-qualified benefit plan trust assets and a reduction in nonutility expenses, including costs related to the cancellation of a proposed gas turbine generation project. Partially offsetting these items was an $8.5 million charge related to a settlement agreement between PGE, the FERC, and other parties related to wholesale power market activities in 2000 and 2001. The increase in Other Income resulted in a $4 million reduction in tax benefits from 2002.

Interest Charges increased $8 million due primarily to an increase in outstanding long-term debt, including first mortgage bonds issued from October 2002 through August 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 $340 million in 2004 compared to $307 million in 2003. The increase was due primarily to an approximate $74 million reduction in payments for power and fuel purchases, a $13 million increase in cash collateral deposits received from certain wholesale customers, and a $5 million decrease in interest payments. These items were partially offset by a $44 million increase in income tax payments to Enron, a $10 million investment in debt securities, and a $5 million decrease in amounts received for sales of electricity.

Cash from operations and remaining proceeds from the issuance of long-term debt (described below) were invested primarily in government money market funds and short-term commercial paper at December 31, 2004. 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), as approved by PGE's board of directors.

Investing Activities consist primarily of improvements to PGE's distribution, transmission, and generation facilities. The $27 million increase in capital expenditures in 2004 is attributable to improvements and expansion of PGE's distribution system to support both new and existing customers within the Company's service territory, efficiency upgrades to the Boardman coal plant, relicensing expenditures, and initial costs of Port Westward. The $21 million change in "Other - net" was due primarily to the early repayment by BPA of certain residential exchange benefits, originally deferred until later years, pursuant to a 2003 agreement.

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 facilities, and long-term financing activities to support such requirements.

During 2004, PGE paid $45 million in matured First Mortgage Bonds and $8 million of conservation bonds and also retired $3 million of preferred stock which had been reflected in long-term obligations on the financial statements. In addition, the Company redeemed the remaining $5 million of 8-1/4% Junior Subordinated Deferrable Interest Debentures, Series A, due in 2035. Pursuant to the redemption, PGE filed in June 2004 to terminate registration of these securities under the Securities Exchange Act of 1934. The Company has de-listed from the New York Stock Exchange and is no longer listed on any stock exchange.

PGE paid $2 million of preferred stock dividends in 2004. In accordance with SFAS 150, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity, which became effective on July 1, 2003, preferred stock dividends are classified as interest expense on the income statement. No cash dividends on common stock were declared or paid in 2002, 2003, or 2004.

PGE has two revolving credit facilities with a group of commercial banks totaling $150 million, consisting of a $50 million 364-day facility and a $100 million three-year facility. The facilities, both of which are unsecured, each contain material adverse effect clauses and financial covenants that limit consolidated indebtedness, as defined in the facilities, to 60% of total capitalization. In addition, the three-year facility requires that PGE maintain an interest coverage ratio, as defined in the facility, of not less that 3.00:1. At December 31, 2004, the Company's indebtedness to total capitalization and interest coverage ratios, as calculated under the facilities, were 41.0% and 6.53:1, respectively. The 364-day facility contains a "term out" option that would allow the Company to extend the final maturity of amounts outstanding at the facility expiration date for up to one additional year. Under the three-year credit facility, PGE has the option to issue letters of credit, in a ddition to borrowings, totaling up to the $100 million. At December 31, 2004, the Company had utilized approximately $2 million in letters of credit, all of which were related to wholesale trading activities. The agreements provide for borrowings at a variable interest rate and require quarterly facility fees based on the Company's unsecured credit rating. In addition, the agreements provide for termination of the banks' obligation, and the full repayment of any outstanding balances, in the event of the sale of the Company's common stock to Oregon Electric or other changes in control, as defined in the agreements. The facilities allow PGE to pay cash dividends on common stock, subject to certain restrictions.

In 2004, existing cash and short term investments, along with cash provided by operations, were used to meet PGE's day-to-day requirements. The Company also has access to the commercial paper market, although no commercial paper was issued in 2003 or 2004.

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, 2004, PGE has the capability to issue additional preferred stock and First Mortgage Bonds in amounts sufficient to meet its anticipated capital and operating requirements.

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 are significantly affected by operating, capital expenditure, debt service, and working capital needs, including margin deposits related to wholesale trading activity. PGE's revolving credit facilities supplement operating cash flow and provide 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 have been established by the Company's management and approved by its board of directors. Such 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. Pending the completion of the anticipated ownership transition, PGE's objective is to maintain a common equity ratio (common equity to total consolidated capitalization, including current debt maturities) at approximately 50%. Achievement of this objective while sustaining sufficient cash flow are necessary to maintain acceptable credit ratings and allow access to long-term capital at attractive interest rates. PGE's common equity ratios were 58.2% and 54.7% at December 31, 2004 and 2003, respectively.

As previously indicated, a significant portion of cash provided by operations consists of depreciation and amortization of utility plant which are recovered in prices. PGE estimates recovery of such charges to approximate $200 million to $230 million annually over the period 2005-2007. Combined with all other sources, total cash provided by operations is estimated to range from $280 million to $315 million annually during the 2005-2007 period.

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

	2005	2006	2007

Capital expenditures (a)	$250 - $270	$360 - $380	$235 - $255
Long-term debt maturities	$30	$11	$70

a. Includes expenditures related to the construction of Port Westward (approximately $70 for 2005, $167 for 2006, and $14 for 2007).

Projected cash flow from operations in excess of cash requirements may be used to fund costs associated with securing new energy resources. If the proposed sale of PGE to Oregon Electric closes, PGE anticipates it will declare and pay a common stock dividend to Oregon Electric in the range of $250 million to $280 million in early 2005. To the extent necessary, long-term debt may be considered to fund any potential cash shortfall. Additional liquidity is available from PGE's revolving credit facilities and access to the commercial paper market. PGE anticipates long-term financing activity of $100 million to $150 million in 2005 and $50 million to $100 million in 2006.

Credit Ratings

PGE's secured and unsecured debt ratings continue to be investment grade from both Moody's Investors Service (Moody's) and Standard and Poor's (S&P). Fitch Ratings (Fitch) rates PGE's secured debt at investment grade and unsecured debt at below investment grade.

PGE's current credit ratings are as follows:

	Moody's	S&P	Fitch
First Mortgage Bonds	Baa2	BBB+	BBB-
Senior unsecured debt	Baa3	BBB	BB
Preferred stock	Ba2	BBB-	B+
Commercial paper	Prime-3	A-2	Withdrawn
Outlook:	Developing	CreditWatch Negative	Positive

S&P's outlook on the Company's credit ratings is based on their view of the consolidated leverage resulting from Oregon Electric's proposed acquisition of PGE from Enron. 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, 2005, PGE had posted approximately $3 million of collateral, consisting of $2 million in letters of credit and $1 million in cash. Based on the Company's non-trading and trading portfolios, estimates of current energy market prices, and the current level of collateral outstanding, as of January 31, 2005, the approximate amount of additional collateral that could be requested upon a single or dual agency downgrade event to below investment grade is approximately $35 million and decreases to approximately $3 million by year-end 2005. In addition to co llateral 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 facilities, increasing the cost of funding the Company's day-to-day working capital requirements. Management believes that the Company's existing lines 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.

In order to increase the degree of insulation between PGE and its insolvent parent company, PGE, in September 2002, created a new class of Limited Voting Junior Preferred Stock and issued a single share of such stock to an independent party. The stock has voting rights which limit PGE's right to commence a voluntary bankruptcy proceeding without the consent of the holder of the share. For further information, see Note 4, Common and Preferred Stock, in the Notes to Financial Statements.

Although measures of PGE's financial performance, including financial ratios, remain strong, due to continuing uncertainty regarding the impact of Enron's bankruptcy on PGE, management is unable to predict what actions, if any, will be taken by the rating agencies in the future. However, PGE management believes there are sufficient structural and regulatory mechanisms to protect the Company's assets from Enron and its creditors and there are no economic incentives for Enron to cause PGE to file for bankruptcy protection. PGE, as a separate corporation, owns or leases the assets used in its business and PGE's management, separate from Enron, is responsible for PGE's day-to-day operations. PGE maintains its own cash management system and finances itself separately from Enron, on both a short- and long-term basis. Neither PGE nor Enron have guaranteed the obligations of the other and there are no loans between them. Under Oregon law and specific conditions imposed on Enron and PGE by t he OPUC in connection with Enron's acquisition of PGE in the merger of Enron and Portland General Corporation in 1997, Enron's access to PGE cash or utility assets (through dividends or otherwise) is limited. PGE is a solvent enterprise whose greatest value is as a going concern. In a bankruptcy, Enron would lose most, if not all, control over PGE. It would merely continue to be the holder of PGE's common stock, and PGE, as a Debtor in Possession, would be managed by its management or, as is the case with Enron in its bankruptcy, new management brought in for that purpose. Any plan of reorganization would be devised by PGE management and approved by PGE's creditors, not Enron or its creditors. No dividends could be paid to Enron, no assets could be sold, and no other transfer of funds could be made except with the approval of the PGE creditors and the Bankruptcy Court. PGE believes that the OPUC would challenge any attempt in the bankruptcy proceedings to sell assets, transfer stock, or otherwise affect the activities of PGE without the approval of the OPUC. Any such challenge would likely result in years of litigation and effectively preclude any transfer of stock, assets, or other funds from PGE to Enron or any other party without OPUC approval.

Contractual Obligations and Commercial Commitments

The following indicates PGE's contractual obligations as of December 31, 2004 (in millions):

	Payments Due (*)						
							After
	Total	2005	2006	2007	2008	2009	2009
Long-Term Debt	$ 922	$ 30	$ 11	$ 70	$ -	$ -	$ 811
Interest on Long-Term Debt	281	61	57	55	54	54	-
Operating Leases	232	10	8	8	8	8	190
Purchase Obligations	269	87	168	14	-	-	-
Trojan Decontamination and Decommissioning Fund	2	1	1	-	-	-	-
Purchased Power and Fuel:							
Electricity Purchases	1,875	532	227	94	95	95	832
Capacity Contracts	260	24	24	24	24	24	140
Natural Gas Agreements	117	26	15	15	13	11	37
Public Utility Districts	69	7	6	6	6	7	37
Coal and Transportation							
Agreements	52	16	4	4	4	4	20
Total	$4,079	$ 794	$ 521	$ 290	$ 204	$ 203	$2,067

(*) Interest on long-term debt is not estimated beyond 2009. Contributions to the Company's pension plan are estimated at $0 for 2005 through 2009 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 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, up to a cumulative maximum of 25% of its percentage Allocation.

Off-Balance Sheet Arrangements

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

Critical Accounting Policies and Estimates

PGE's consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States (GAAP). In addition, the Company's accounting policies comply with requirements and rate making practices of jurisdictional regulatory authorities. To reflect the effect of regulation, certain revenues, costs, and gains, which would otherwise be recorded in income under GAAP, are deferred for future rate making treatment under SFAS No. 71, Accounting for the Effects of Certain Types of Regulation, when it is probable that these costs or refunds will be reflected in future prices. In making this probability assessment, management considers supporting evidence, including deferred accounting orders and previous rate making treatment on the same or similar costs, before recording a regulatory asset or regulatory liability. As recoveries or refunds are reflected in future prices, the applicable regulatory asset or regulatory liability balance s are amortized to income over the recovery or refund period. Such deferred assets and liabilities are titled "Regulatory assets" and "Regulatory liabilities" on the Consolidated Balance Sheets; balances were $295 million and $360 million, respectively, at December 31, 2004.

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 estimat es 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.

Asset Retirement Obligations

SFAS No. 143 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 Amor tization 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, 2004 was $96 million, measured at estimated fair value. 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 activ ities over a period extending to 2019 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 ISFSI.

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, 2004, 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 initially estimated refund amount. Reserves of $17.5 million were established at December 31, 2002 and increased to $40 million at December 31, 2003 due to changes in the FERC's methodology. As of December 31, 2004, the reserve remains at $40 million. As an unresolved legal and regulatory matter, both the refund methodology and potential refund estimate may vary significantly in the future, which could have a material impact on PGE's results of operations.

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Price Risk Management

PGE engages in price risk management activities for both non-trading and trading purposes, utilizing derivative instruments such as electricity forward, swap, and option contracts, and natural gas forward, swap, option, and futures contracts. Derivative contracts entered into for non-trading electric utility purposes are anticipated to serve the Company's regulated retail load. Non-trading derivative contracts are utilized 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. PGE has entered into derivative contracts for trading purposes to participate in electricity and natural gas markets; such activities are not reflected in PGE's retail prices. Derivative contracts are accounted for under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended by SFAS No. 137, SFAS No. 138, and SFAS No. 149. For non-trading activities , certain derivative instruments are recorded at fair value on the balance sheet and, to the extent these instruments are included in the Company's Resource Valuation Mechanism (RVM), the 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. For trading contracts, PGE records 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 the resulting gain or loss of value in either earnings or other comprehensive income for the period. This change in value represents the difference between the contract price and the current market value of the contract. 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 and the expected return on plan assets. 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. The Company reduced its discount rate to reflect a decrease in the rate of return on such bonds.

PGE's assumption regarding the expected rate of return on plan assets is 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, 2004, the plan's assets were comprised of approximately 70% equities and 30% other assets.

Changes in actuarial assumptions can materially affect net periodic pension income. Reducing the expected long-term rate of return on plan assets by 0.25% would have decreased 2004 pension income by approximately $1.1 million. Reducing the discount rate by 0.25% would have increased 2004 pension expense by approximately $1.5 million.

Transactions with Related Parties

PGE's services to affiliated companies consist primarily of employee and administrative services. The Company also receives services from affiliated companies for employee benefit plans and certain insurance coverage. Transactions with affiliated companies are subject to regulation by the OPUC and, since Enron registered as a holding company, by the SEC. Most affiliated interest transactions are made under a Master Service Agreement (MSA) filed with the Commission and the SEC. Most transactions not covered by the MSA must be separately approved. 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. Under SEC regulations, affiliated services are charged at cost. Services will be provided at cost, unless there is a conflict between OPUC and SEC regulations, in which case PGE and Enron have agreed not to provide the services until the matter ca n be resolved.

On October 15, 2002, PGE submitted proofs of claim to the Bankruptcy Court for amounts representing intercompany obligations between PGE and Enron and its bankrupt subsidiaries arising prior to the commencement of the bankruptcy case. In December 2004, PGE made a distribution to Enron of all pre-petition amounts owed by Enron and its affiliates, and related proofs of claim, except for those related to Portland General Holdings, Inc. The distribution was made in an effort to eliminate all pre-petition intercompany balances from PGE's books in order to remove the uncertainties regarding the value of the proofs of claim. For further information, see "Enron Bankruptcy" in "Financial and Operating Outlook" of this Item 7.

Trading Activities Accounted for at Fair Value

PGE trading activities utilize 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. At December 31, 2004, all energy trading contracts have a maturity of one year or less. In early 2005, PGE discontinued its trading activities; existing trading transactions will continue to settle through December 31, 2005.

The following tables indicate fair value, and changes in fair value, of PGE's trading contracts in 2004 and 2003, as well as the source of the fair value of the unrealized gain at December 31, 2004 (in millions):

	Unrealized Gain (Loss)	
	2004	2003
Unrealized gain (loss) of contracts as of January 1	$ -	$ (1)
Less contracts realized during year:		
Contracts entered in prior years	-	-
Contracts entered in current year	-	(1)
Change in fair value attributable to market changes:		
Contracts entered in prior years	-	-
Contracts entered in current year	1	2
Unrealized gain (loss) of contracts as of December 31	$ 1	$ -

	Unrealized Gain on Trading Contracts at Year End			
Source of Fair Value At December 31, 2004	Maturity 0 - 6 mos.	Maturity 6 - 12 mos.	Maturity over 1 yr.	Total Unrealized Gain
Prices actively quoted	$ 1	$ -	$ -	$ 1
Prices provided by other external sources	-	-	-	-
Prices based on models and other valuation methods	-	-	-	-

Financial and Operating Outlook

Retail Customer Growth and Energy Deliveries

Weather adjusted retail energy deliveries to PGE and ESS customers increased 1.1% in 2004 compared to 2003. The increase was due primarily to 3.3% and 3.5% increases, respectively, from residential and commercial customers, due to both an approximate 13,000 increase in the number of customers served and to an improved economy. This increase was partially offset by the loss of a large industrial customer that now generates its own power requirements. PGE forecasts total energy deliveries to PGE and ESS customers to increase by approximately 2% in 2005.

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 continue at below average levels in 2005. 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-July 2005 runoff (as measured at The Dalles, Oregon) at 69% of normal, compared to actual runoffs of 77% in 2004 and 83% in 2003. In 2005, hydro conditions in the Clackamas and Deschutes river systems, where PGE's facilities are located, are projected to be 55% and 69% of normal, respectively, compared to actual runoffs of approximately 82% and 87% of normal, respectively, in 2004.

Additional factors that could affect the availability and price of purchased power and fuel include weather conditions in the Northwest during winter months and in the Southwest during summer months, as well as the performance of major generating facilities in both regions.

Price Risk Management - As PGE's primary business is to serve its retail customers, the Company uses derivative instruments to manage its exposure to commodity price risk and to minimize net power costs for customers. Under SFAS No. 133, as amended, PGE records unrealized gains and losses in earnings in the current period for derivative instruments that do not qualify for either the normal purchases and normal sales exception or cash flow hedge accounting. Derivative instruments that qualify for the normal purchases and normal sales exception are recorded in earnings on a settlement basis, and cash flow hedges are recorded in Other Comprehensive Income 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.

Enron Bankruptcy

Bankruptcy Proceedings and Chapter 11 Plan

Commencing in December 2001, Enron and certain of its subsidiaries (Debtors) filed for bankruptcy under Chapter 11 of the federal Bankruptcy Code. PGE is not included in the bankruptcy, but the common stock of PGE held by Enron is part of the bankruptcy estate.

The Debtors filed their proposed joint Chapter 11 plan (the Chapter 11 Plan) and related disclosure statement (the Disclosure Statement) with the Bankruptcy Court. The Chapter 11 Plan and Disclosure Statement, as amended, provide information about the assets that are in the bankruptcy estate, including the common stock of PGE, and how those assets will be distributed to the creditors. The Chapter 11 Plan and the Disclosure Statement 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. The Chapter 11 Plan has been approved by the creditors and was confirmed by the Bankruptcy Court on July 15, 2004. On November 17, 2004, the Chapter 11 Plan became effective.

Enron has entered into an agreement to sell PGE, which has been approved by the Bankruptcy Court and is included in the Chapter 11 Plan. The sale requires certain regulatory approvals. Under the Chapter 11 Plan, if PGE is not sold, either under the current agreement or to another buyer, PGE's common stock will be distributed over time to the Debtors' creditors. Once a sufficient amount of common stock is distributed, it is anticipated that PGE's shares would be publicly traded.

Proposed Sale of PGE

On November 18, 2003, Enron and Oregon Electric, a newly-formed Oregon limited liability company financially backed primarily by investment funds managed by Texas Pacific Group, entered into an agreement by which Enron will sell all of the issued and outstanding common stock of PGE to Oregon Electric. The transaction is valued at approximately $2.35 billion, including the assumption of debt. The final amount of consideration will be determined on the basis of PGE's financial performance between January 1, 2003 and closing. The transaction, previously approved by the Enron Board of Directors and supported by the Official Unsecured Creditors' Committee, was approved by the Bankruptcy Court on February 5, 2004. The transaction also requires approval of the OPUC, the SEC, the FERC, and certain other regulatory agencies. Applications for approval of the acquisition of PGE by Oregon Electric have been filed with the OPUC (on March 8, 2004), the FERC (on April 6, 2004), an d the SEC (on July 29, 2004). On January 3, 2005, the Oregon Energy Facility Siting Council issued a declaratory ruling that the proposed acquisition is not a transfer of ownership that would require a transfer of certain generating plant site certificates held by PGE. On February 14, 2005, the NRC approved the proposed acquisition.

In July 2004, the OPUC Staff and other intervenors filed their initial testimony that the sale of PGE to Oregon Electric not be approved unless greater net benefits for customers of PGE can be demonstrated. In September 2004, OPUC Staff recommended approval of the sale subject to certain conditions, including customer rate credits and limitations on distributions from PGE to Oregon Electric. Oregon Electric responded to concerns raised by the staff and other intervenors in subsequent rebuttal testimony and settlement meetings. Hearings and final oral arguments were held in late 2004. On March 10, 2005, the OPUC issued Order No. 05-114, in which it denied Oregon Electric's application to purchase PGE. Enron and Oregon Electric have stated that they are carefully reviewing the Order and evaluating their next steps.

If PGE is not sold to Oregon Electric, under the Chapter 11 Plan, Enron will either sell the Company to another buyer or distribute shares of PGE's common stock over time to the Debtors' creditors. Until shares are distributed to creditors, Enron will retain the right to sell PGE if it is determined that a sale would be in the best interest of the creditors. Until the sale to Oregon Electric is approved, another filing related to the sale of PGE is approved, or PGE's common stock is distributed to the Debtors' creditors, management cannot assess the impact on PGE's business and operations of a sale or the distribution of PGE's stock to the Debtors' creditors.

Liabilities and Impairments

Although PGE is not included in the Enron bankruptcy, it has been affected. Numerous shareholder and employee class action lawsuits have been initiated against Enron, its former independent accountants, legal advisors, executives, and board members. In addition, investigations of Enron have been commenced 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 the general effects discussed above, PGE may have potential exposure to certain liabilities and asset impairments as a result of Enron's bankruptcy. These are:

1. **Amounts Due from Enron and Enron-Supported Affiliates in Bankruptcy** - On October 15, 2002, PGE submitted proofs of claim to the Bankruptcy Court for amounts representing intercompany obligations between PGE and Enron and its bankrupt subsidiaries arising prior to the commencement of the bankruptcy case. In December 2004, PGE made a distribution to Enron of all pre-petition amounts owed by Enron and its affiliates, and related proofs of claim, except for those related to Portland General Holdings, Inc. The distribution was made in an effort to eliminate all pre-petition intercompany balances from PGE's books in order to remove the uncertainties regarding the value of the proofs of claim. Following the distribution, PGE's balance sheet was cleared of all pre-petition intercompany balances with Enron and its affiliates, with the exception of PGH. As of December 31, 2004, PGE has outstanding accounts receivable of $5 million due from PGH which is part of the Enron b ankruptcy proceedings. Based on management's assessment of the realizability of accounts receivable from PGH, a reserve of $1 million has been established.

2. **Controlled Group Liability** - Enron's bankruptcy has raised questions regarding potential PGE liability for certain employee benefit plans and tax obligations of Enron.

<u>Pension Plans</u>

Funding Status

The pension plan for the employees of PGE (the PGE Plan) is separate from the Enron Corp. Cash Balance Plan (the Enron Plan). At December 31, 2004, the total fair value of PGE Plan assets was $2 million higher than the projected benefit obligation on a SFAS No. 87 (Employers' Accounting for Pensions) basis. In addition, the PGE Plan was over-funded on an accumulated benefit obligation basis by about $58 million as of December 31, 2004.

Enron's management has informed PGE that, as of December 31, 2004, the assets of the Enron Plan were less than the present value of all accrued benefits by approximately $48 million on a SFAS No. 87 basis and approximately $166 million on a plan termination basis. The Pension Benefit Guaranty Corporation (PBGC) insures pension plans, including the PGE Plan and the Enron Plan and the pension plans of other Debtors. Enron's management has informed PGE that the PBGC has filed claims in the Enron bankruptcy cases with respect to the Enron Plan and the plans of the other Debtors (Pension Plans). The claims are duplicative in nature because certain liability under ERISA is joint and several. Five of the PBGC's claims represent unliquidated claims for PBGC insurance premiums (the Premium Claims), five are unliquidated claims for due but unpaid minimum funding contributions (the Contribution Claims) under the Internal Revenue Code of 1986, as amended, and ERISA, 26 U.S.C. Section 412, and 29 U.S.C. Section 1082, and the remaining five claims are for unfunded benefit liabilities (the UBL Claims). PBGC has informed the Debtors that it has reduced its aggregate estimate of the UBL Claims for the Pension Plans to $321.8 million, including $240.2 million for the Enron Plan and $64.6 million related to the PGE Plan, although it has not amended the UBL Claims to reflect those amounts. Except for one PBGC premium which is not material, the Debtors are current on their PBGC premiums and their minimum funding contributions to the Pension Plans. Therefore, the Debtors' value the Premium Claims and the Contribution Claims at $0. Enron management has informed PGE that the PBGC has informally alleged in pleadings filed with the Bankruptcy Court that the UBL claim related to the Enron Plan could increase by as much as 100%. PBGC has not provided support (statutory or otherwise) for this assertion and Enron management disputes the validity of any such claim.

Because the Enron Plan is underfunded, in certain circumstances the Enron Plan may be terminated and taken control of by the PBGC upon approval of a Federal District Court. In addition, with consent of the PBGC, Enron could seek to terminate the Enron Plan while it is underfunded. Moreover, if it satisfies certain statutory requirements, Enron can commence a voluntary termination by fully funding the Enron Plan, in accordance with the Enron Plan terms, and terminating it in a "standard" termination in accordance with the Employee Retirement Income Security Act of 1974, as amended (ERISA).

Upon termination of an underfunded pension plan, all of the members of the ERISA controlled group of the plan sponsor become jointly and severally liable for the plan's underfunding. The PBGC can demand payment from one or more of the members of the controlled group. If payment is not made, a lien in favor of the PBGC automatically arises against all of the assets of that member of the controlled group. The amount of the lien is equal to the lesser of the underfunding or 30% of the aggregate net worth of all of the controlled group members. In addition, if the sponsor of a pension plan does not timely satisfy its minimum funding obligation to the pension plan, once the aggregate missed amounts exceed $1 million, a lien in favor of the plan in the amount of the missed funding automatically arises against the assets of every member of the controlled group. In either case, the PBGC may file to perfect the lien and attempt to enforce it against the assets of the plan sponsor and the members of its controlled group. PGE management believes that the lien would be subordinate to prior perfected liens on the assets of the members of the controlled group. Substantially all of PGE's assets are subject to a prior perfected lien in favor of the holders of its First Mortgage Bonds. PGE management believes that any lien asserted by the PBGC would be subordinate to that lien. In addition, the PBGC retains an interest in any sales proceeds generated by the Enron auction process for PGE.

On January 30, 2004, the Bankruptcy Court entered the order authorizing Enron and certain of its affiliated Debtors to contribute $200 million to the Pension Plans and terminate them in a manner that should eliminate the PBGC's claims. However, there can be no assurance that Enron will have the ability to obtain funding for accrued benefits on acceptable terms, that certain funding contingencies will be met, or that the required government agencies that review pension plan terminations will approve the termination of the Pension Plans. If the proposal to fund and terminate the Enron Plan is approved and consummated, it should eliminate any need for the PBGC to attempt to collect from PGE any liability related to the Enron Plan.

On June 2, 2004, the PBGC issued notices to Enron and Enron Facility Services, Inc. (EFS), an Enron affiliate, stating that the PBGC had determined that the Pension Plans should be terminated. On June 3, 2004, the PBGC filed a complaint (PBGC Complaint) in the District Court for the Southern District of Texas against Enron seeking an order (i) terminating the Pension Plans; (ii) appointing the PBGC the statutory trustee of the Pension Plans; (iii) requiring transfer to the PBGC of all records, assets or other property of the Pension Plans required to determine the benefits payable to the Pension Plans' participants; and (iv) establishing June 3, 2004 as the termination date of the Pension Plans.

The PGE Plan was not included in the above Complaint, nor was PGE issued a similar notice of determination regarding the PGE Plan. The PBGC has taken no action to terminate the PGE Plan.

On August 4, 2004, Enron, EFS and certain Debtors filed a complaint with the Bankruptcy Court (Enron Complaint) seeking (i) a declaration that the PBGC Complaint is void; and (ii) orders staying, restraining and enjoining the PBGC from continuing the prosecution of the PBGC Complaint and preliminarily and permanently enjoining the PBGC to cease prosecution of, and to dismiss with prejudice, the PBGC Complaint. On September 8, 2004, the Bankruptcy Court denied the Enron Complaint.

Unless and until the District Court authorizes the PBGC to terminate the Pension Plans and the PBGC makes a demand on PGE to pay some or all of any unfunded benefit liabilities under the Pension Plans, which would not occur unless the Proposed Pension Settlement (as described below) is not approved by both the District and Bankruptcy Courts or the parties do not satisfy the terms of the Proposed Pension Settlement, PGE has no liability for the unfunded benefit liabilities and no termination liens arise against any PGE property.

Proposed Settlement

Enron management has informed PGE management that Enron has reached a settlement in principle (Proposed Pension Settlement) with the PBGC, the terms of which have not yet been disclosed. As a result, the PBGC and Enron have filed to stay the PBGC Complaint. The Proposed Pension Settlement must be filed and approved by the District Court and the Bankruptcy Court and all terms of the Proposed Pension Settlement must be satisfied for the contingent liability against PGE by the PBGC to be relinquished. If the Proposed Pension Settlement is not approved by both the District and Bankruptcy Courts or the parties do not satisfy all the terms of the Proposed Pension Settlement, and if the relief sought in the Enron Complaint is not obtained when the stay is lifted, Enron may be precluded from funding and terminating the Pension Plans as previously authorized by the Bankruptcy Court until, if at all, after resolution of the PBGC Complaint as the stay with respect to such litigation also would be lifted. In addition, in that case it may be possible, subject to applicable law, for the Enron Plan and PGE Plan to be merged while Enron and PGE are in the same controlled group, and any excess assets in the PGE Plan would reduce the deficiency in the Enron Plan. However, if the plans are not merged, the deficiency in the Enron Plan could become the responsibility of the PBGC and the PGE Plan assets would be undiminished.

If the Proposed Pension Settlement is approved, Enron would proceed with the standard termination of the Pension Plans as discussed above and any need for the PBGC to attempt to collect from PGE any liability related to the Enron Plan would be eliminated.

PGE management cannot predict the outcome of the above matters or estimate any potential loss. In addition, if the PBGC did look solely to PGE to pay any amount with respect to the Enron Plan, PGE would exercise all legal rights, if any, available to it to defend against such a demand and to recover any contributions from the other solvent members of the controlled group. No reserves have been established by PGE for any amounts related to this issue.

Minimum Funding Obligation

If the sponsor of a pension plan does not timely satisfy its minimum funding obligation to the pension plan, once the aggregate missed amounts exceed $1 million, a lien in the amount of the missed funding automatically arises against the assets of every member of the controlled group. The lien is in favor of the plan, but may be enforced by the PBGC. The PBGC may perfect the lien by appropriate filings. PGE management believes that the lien would not take priority over other previously perfected liens on the assets of a member of the controlled group. If Enron does not timely satisfy its minimum funding obligation in excess of $1 million, a lien will arise against the assets of PGE and all other members of the Enron controlled group. The PBGC would be entitled to perfect the lien and enforce it in favor of the Enron Plan against the assets of PGE and other members of the Enron controlled group. However, substantially all of PGE's assets are subject to a prior perfected lien in fav or of the holders of its First Mortgage Bonds. PGE management believes that any lien asserted by the PBGC would be subordinate to that lien.

Based on discussions with Enron management, PGE's management understands that Enron has made all required contributions to date. PGE does not know if Enron will make contributions as they become due. PGE management is unable to predict if Enron will miss a payment and, if so, whether the PBGC would seek to have PGE make any or all of the payment. If the PBGC did look solely to PGE to pay the missed payment, PGE would exercise all legal rights, if any, available to it to defend against such a demand and to recover contributions from the other solvent members of the Enron controlled group. Until Enron misses contributions exceeding $1 million, PGE has no liability and no liens will arise against any PGE property. Other members of Enron's controlled group could, to the extent of any legal rights available to them, seek contribution from PGE for their payment of any missed payments demanded by the PBGC. No reserves have been established by PGE for any amounts related to this issue.

Retiree Health Benefits

PGE management understands, based on discussions with Enron management, that Enron maintains a group health plan for certain of its retirees. If retirees of Enron lose coverage under Enron's group health plan for retirees due to Enron's bankruptcy proceedings, the retirees must be provided the opportunity to purchase continuing coverage (known as COBRA Coverage) from an Enron group health plan, if any, or the appropriate group health plan of another member of the controlled group. The liability for benefits under the Enron group health plan for retirees (other than the potential liability to provide COBRA Coverage) is not a joint and several obligation of other members of the Enron controlled group, including PGE, so PGE would not be required to assume from Enron, or otherwise pay, any liabilities from the Enron group health plan. Neither PGE nor any other member of Enron's controlled group would be required to create new plans to provide COBRA Coverage for Enron's retirees, and the re tirees would not be entitled to choose the plan from which to obtain coverage. Retirees electing to purchase COBRA Coverage would be provided the same coverage that is provided to similarly situated retirees under the most appropriate plan in the Enron controlled group. Retirees electing to purchase COBRA Coverage would be required to pay for the coverage, up to an amount not to exceed 102% of the cost of coverage for similarly situated beneficiaries. Retirees are not required to acquire COBRA Coverage. Retirees will be able to shop for coverage from third party sources and determine which is the least expensive coverage.

PGE management believes that in the event Enron terminates retiree coverage, any material liability to PGE associated with Enron retiree health benefits is unlikely for two reasons. First, based on discussions with Enron management, PGE management understands that most of the retirees that would be affected by termination of the Enron plan are from solvent members of the controlled group and few, if any, live in Oregon. PGE management believes that it is unlikely that any PGE plans would be found to be the most appropriate to provide COBRA coverage. Second, even if a PGE plan were selected, PGE management believes that retirees in good health should be able to find less expensive coverage from other providers, which will reduce the number of retirees electing COBRA Coverage. PGE management believes that the additional cost to PGE to provide COBRA Coverage to a limited number of retirees that are unable to acquire other coverage because they are difficult to insure or have preexisting condi tions will not be material. No reserves have been established by PGE for any amounts related to this issue.

Income Taxes

Under regulations issued by the U.S. Treasury Department, each member of a consolidated group during any part of a consolidated federal income tax return year is severally liable for the tax liability of the consolidated group for that year. PGE became a member of Enron's consolidated group on July 2, 1997, the date of Enron's merger with PGC. Based on discussions with Enron's management, PGE management understands that Enron has treated PGE as having ceased to be a member of Enron's consolidated group on May 7, 2001 and becoming a member of Enron's consolidated group once again on December 24, 2002. On December 31, 2002, PGE and Enron entered into a tax allocation agreement pursuant to which PGE agreed to make payments to Enron that approximate the income taxes for which PGE would be liable if it were not a member of Enron's consolidated group. Due to the uncertainty with the reconsolidation during 2003, PGE held certain tax payments due Enron. Enron obtained an ag reement from the IRS on February 2, 2004 stipulating that PGE did become a member of the Enron consolidated group on December 24, 2002. PGE resumed tax payments due Enron in early 2004.

Enron's management has provided the following information to PGE:

A. Enron's consolidated tax returns through 1995 have been audited and are closed.

B. The IRS has completed an audit of Enron's consolidated tax returns for 1996-2001. For years 1996 through 1999, Enron and its subsidiaries generated substantial net operating losses (NOLs). For 2000, Enron and its subsidiaries paid an alternative minimum tax. Enron's 2001 consolidated tax return showed a substantial net operating loss, which was carried back to the tax year 2000, for which Enron seeks a tax refund for taxes paid in 2000. The carryback of the 2001 loss to 2000 is expected to provide Enron and its subsidiaries with substantial NOLs which may be used to offset additional income tax liabilities that may result from future IRS audits for the taxable periods PGE was a member of Enron's consolidated federal income tax returns.

C. Enron's 2003 tax return was filed on September 14, 2004. As noted in paragraph B. above, Enron expects to have substantial NOLs from operations in years preceding 2003. Enron had 2003 NOLs sufficient to eliminate Enron's regular and alternative minimum income tax liabilities for 2003 and expects to have sufficient NOLs to offset its regular income tax liability for all subsequent periods through the date of consummation of its Chapter 11 Plan.

On March 28, 2003, the IRS filed various proofs of claim for taxes in the Enron bankruptcy, including a claim for approximately $111 million with respect to income tax, interest, and penalties for taxable years in which PGE was included in Enron's consolidated tax return. The IRS has amended the proof of claim to reduce it to $20 million. The IRS and Enron reached a settlement on Enron's 1996-2001 tax liability on January 5, 2005. The settlement shows no net taxes due by Enron to the IRS. In the meantime, however, the settlement eliminates any further assessment of tax, interest or penalty for the years 1996-2001 against PGE and any other member of the consolidated group in those years in excess of the overpayment currently held by the IRS.

However, with respect to periods after 2001, PGE would potentially remain severally liable for post-petition interest, as well as any portion of the claim allowed in the bankruptcy that the IRS does not collect from the debtors.

To the extent, if any, that the IRS would look to PGE to pay any assessment not paid by Enron, PGE would exercise whatever legal rights, if any, that are available for recovery in Enron's bankruptcy proceeding, or to otherwise seek to obtain contributions from the other solvent members of the consolidated group. As a result, management believes the income tax, interest, and penalty exposure to PGE (related to any future liabilities from Enron's consolidated tax returns during the period PGE was a member of Enron's consolidated returns) would not be material. No reserves have been established by PGE for any amounts related to this issue.

PGE management cannot predict with certainty what impact the Chapter 11 Plan may have on PGE if PGE is not sold to Oregon Electric. However, since the Chapter 11 Plan has become effective, the assets and liabilities of PGE will not become part of the Enron estate in bankruptcy.

In addition, PGE management does not believe that there is any incentive for Enron or its creditors to take PGE into bankruptcy. PGE is a solvent enterprise whose greatest value is as a going concern. As a solvent enterprise in bankruptcy, PGE would owe fiduciary obligations to its shareholders and creditors. If a bankruptcy were commenced, the United States Trustee would form a creditors' committee comprised of PGE's largest creditors, and any plan of reorganization would be subject to confirmation by the Bankruptcy Court. Prior to the effectiveness of such plan, no dividends could be paid to Enron, and no assets could be sold, or transfer of funds could be made, outside the ordinary course of business except with the approval of the Bankruptcy Court. Further, PGE would continue to be required to operate its business according to Oregon law, and the OPUC would not be stayed from enforcing its police and regulatory powers. Since the issue of whether a Bankruptcy Court has the authority to supersede state regulation of a utility has not been resolved, PGE believes that the OPUC would challenge any attempt to sell assets, transfer stock, or otherwise affect the activities of PGE without the approval of the OPUC. Any such challenge would likely result in litigation. As a result, PGE believes that the economic interests of Enron and its creditors are better served by pursuing their present course. On September 30, 2002, the Company issued to an independent shareholder a single share of a new $1.00 par value class of Limited Voting Junior Preferred Stock which limits, subject to certain exceptions, PGE's right to commence any voluntary bankruptcy, liquidation, receivership, or similar proceedings without the consent of the shareholder.

Threatened Litigation - Non-Qualified Benefit Plans

In 1983, PGE adopted certain non-qualified deferred compensation arrangements and associated "rabbi" trusts for the benefit of key employees, officers, and directors. In 1989, sponsorship of these arrangements was transferred to Portland General Corporation (which was subsequently merged into Enron in 1997) and in 1997 sponsorship was transferred to PGH. Although plan sponsorship was transferred, PGE continued to participate in these plans as a participating employer for the benefit of its own employees. Portland General Corporation, PGH, and certain of their subsidiary companies also had employees who participated in these plans. The plan documents specifically provide that: (1) a participating employer's obligation under the plans shall be that of an unfunded and unsecured promise to pay money in the future; and, (2) the payment of a participant's benefit pursuant to the plan shall be borne solely by the participating employer that employs the participant and reports the par ticipant as being on its payroll during the accrual or increase of the plan benefit, and no liability for the payment of any plan benefit shall be incurred by reason of plan sponsorship or participation except for the plan benefits of a participating employer's own employees. Upon the bankruptcy filing by Enron and certain of its affiliates, and the subsequent bankruptcy filing of PGH, payment by those companies of participant benefits under these plans ceased. Since PGE is not in bankruptcy, benefit payments to participants due benefits from PGE have continued. Plan participants with benefits due from the bankrupt companies have sought to have the companies or the trusts commence payments without success. Certain of these Plan participants have indicated their intention to commence a lawsuit against PGE and other parties if they are unable to reach a resolution with respect to their benefit payments. If any lawsuit is filed, PGE intends to vigorously defend that case.

Enron and representatives of the plan participants have reached a settlement that was approved by the Bankruptcy Court on February 24, 2005, which will become final upon acceptance, including a release of any claims against PGE by the plan participants. Under the settlement, PGE will receive approximately $8.4 million (net of tax) in consideration for assuming the administration and payment of non-qualified benefit plan obligations for certain PGH plan participants.

Public Ownership Initiatives

City of Portland

The City Council of Portland, Oregon received professional advice regarding the City's potential acquisition of PGE, including possible condemnation of PGE's assets. The City participated in Enron's auction process, but did not participate in the overbid process following the Bankruptcy Court filing of Texas Pacific Group's agreement to purchase PGE. The City has publicly announced that, if the proposed sale of PGE to Oregon Electric does not close, the City intends to pursue the acquisition of PGE.

Peoples' Utility Districts

Proponents of the formation of Peoples' Utility Districts (PUDs) to acquire PGE's facilities and equipment in the Company's allocated service territory obtained sufficient certified signatures on initiative petitions to place measures on election ballots in Multnomah, Yamhill, Clackamas, and Washington Counties in Oregon. Formation initiatives in these counties were rejected by voters in November 2003, March 2004, May 2004, and November 2004, respectively.

If PUDs are formed, they would have the authority to condemn PGE's distribution assets within the boundaries of the districts. Oregon law prohibits a PUD from condemning thermal generation plants. It is uncertain under Oregon law whether a PUD would be able to condemn PGE's hydro generation plants.

PGE opposes the formation of PUDs in its service territory and will oppose any efforts to condemn PGE's assets.

Complaint to OPUC - Income Taxes

On March 7, 2003, the URP and Linda K. Williams (Complainants) filed a petition to open an investigation and a complaint with the OPUC with respect to the amount of federal, state, and local income taxes paid by PGE since 1997. On March 31, 2003, the OPUC rejected the request for an investigation and on July 9, 2003 issued an order that dismissed the complaint. On September 22, 2003, the OPUC denied the Complainants' request for reconsideration. On December 23, 2003, the URP appealed to the Marion County Circuit Court the OPUC decision not to investigate PGE's tax payments and on June 4, 2004 the Court reversed the OPUC decision and remanded the matter to the OPUC to proceed on Complainants' allegation that the estimates included in rates for taxes was based on fraud and deceit. The OPUC has commenced further proceedings as directed by the Court. PGE is vigorously contesting the allegations.

Class Action Lawsuit - Multnomah County Business Income Taxes

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 violati ons, and seeking punitive damages. On February 24, 2005, PGE requested a declaratory ruling from the OPUC on this matter. Management cannot predict the ultimate outcome of this matter.

Resource Valuation Mechanism

A general rate order issued by the OPUC in 2001 approved a new Resource Valuation Mechanism (RVM) tariff 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, filed annually in April and finalized in mid-November, which is effective 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. Prices for business customers were affected more by wholesale energy market prices, which decreased in the 2003 forecast. The smaller decrease in residential prices reflected both PGE's cost of generation as well as the higher cost of electricity from BPA, which increased its rates in October 2002. These price decreases reduced PGE's 2003 revenues by approximately $90 million.

Power Cost Price Increase - 2004 Based upon power cost projections in PGE's 2004 RVM filing, the OPUC authorized an approximate 0.4% average price increase for the Company's retail customers 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 PGE's 2001-2002 power cost adjustment mechanism (see "Power Cost Adjustment Mechanisms" below for further information). Price adjustments increased PGE's 2004 revenues by approximately $4 million. A stipulation between PGE, OPUC staff, and intervenors related to the Company's forecast of 2004 power costs provided that PGE withdraw a proposed power cost adjustment mechanism for 2004 and participate in a process to address the need for, and structure of, a cost recovery mechanism for variances in power costs f rom forecasted levels. Although PGE engaged in the process, no definitive outcome was reached. The Company is currently focusing its attention on the effect of hydro variations on power costs, as described below.

Power Cost Price Increase - 2005 Based upon power cost projections in PGE's 2005 RVM filing, the OPUC authorized an approximate 1.4% average price increase for the Company's retail customers for 2005. Price adjustments range 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. Based upon projected energy sales, it is estimated that the price adjustments will result in an approximate $17 million increase in PGE's 2005 revenues.

Power Cost Adjustment Mechanisms - 2001 and 2002

In order to protect both PGE and its customers from price volatility in the wholesale power and natural gas markets, the OPUC authorized the Company to defer for later recovery from retail customers actual net variable power costs which differed from certain baseline amounts approved by the Commission. Under the initial power cost adjustment mechanism, which covered the period January through September 2001, PGE's net variable power costs, as calculated under terms approved by the OPUC, exceeded the baseline. The Company received OPUC approval to recover the approximate $91 million balance (including interest) over a 3 1/2-year period (April 2002 - September 2005). At December 31, 2004, the remaining balance to be collected was approximately $19 million.

In its August 2001 general rate order, the OPUC approved a power cost adjustment mechanism for the period October 2001 through December 2002. Under this mechanism, PGE deferred approximately $41 million in power costs, representing the difference between actual net variable power costs and the amount used to establish base energy rates, as well as the difference between actual energy revenues and a pre-determined base. The deferred amount was collected over a two-year period (January 2003 - December 2004), with recovery from large industrial customers completed during 2003.

PGE did not have power cost adjustment mechanisms in place for 2003 and 2004.

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 electric prices. In July 2004, PGE requested OPUC consideration of a Hydro Generation Adjustment tariff that would allow rate adjustments reflecting changes in power costs caused by variations in hydro conditions. A procedural schedule has been adopted for further consideration of the mechanism by the Commission.

In anticipation of the effects of poor hydro conditions in 2005, the Company on December 30, 2004 filed with the OPUC an "Application for Deferral of Costs and Benefits due to Hydro Generation Variance" that would defer costs, beginning on January 1, 2005, for future amortization in prices. Decisions by the OPUC on both the Hydro Generation Adjustment tariff and the deferral application are expected in 2005.

Port Westward Project

In September 2004, PGE entered into agreements with the general contractor and turbine manufacturer for construction of Port Westward. Groundbreaking took place on October 7, 2004 and full construction began in February 2005. Port Westward is scheduled to be operational by mid-2007 and cost approximately $275 million to $295 million (including AFDC).

Hydro Relicensing

A Settlement Agreement was signed on July 13, 2004 by all parties to the Pelton Round Butte relicensing proceeding. The Settlement Agreement resolves all issues raised by the 2001 joint application that was submitted to the FERC by PGE and the Confederated Tribes of the Warm Springs Reservation of Oregon, the project's co-owners. It includes a recommendation that the FERC issue a 50-year license for the project and also includes provisions for fish passage over the project's dams. The Agreement was submitted to the FERC on July 30, 2004, with approval expected by mid-2005.

Mid-Columbia Hydro Matters

PGE's long-term power purchase contracts with certain public utility districts in the state of Washington expire between 2005 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 new agreements are effective upon expiration of the current contracts in 2005 and 2009 for Priest Rapids and Wanapum, respectively, and are subject to FERC approval. 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. PGE's share of the output will decline over time as Grant's needs increase, with the Company's share in the two projects reduced from the current 237 MW to an estimated 189 MW in 2009. Also under the agreements, PGE will purchase an additional 41 average megawatts of power during the period 2005 through 2011.

In 2003, the Colville Confederated Tribes (Colville Tribe) presented a claim to Douglas County PUD (Douglas) based upon alleged annual charges for the Wells Hydroelectric Project (Project) for the use of Colville tribal lands. The Colville Tribe claimed that annual charges would also be due for periods into the future. PGE purchases 20.3% of the power generated by the Wells Project. In November 2004, Douglas and the Colville Tribe entered into a settlement that resolved all the Colville Tribe's claims. The settlement, which was approved by the FERC in February 2005, will impact the quantity and price of future output purchased by PGE. It requires that Douglas pay a lump sum of $13.5 million, convey certain real property, and allocate (at cost) 4.5% of the Project's output to the Colville Tribe. The Colville Tribe's allocation of the Project's output will increase to 5.5% after 2018 and for the remaining life of the Project. Also in November 2004, Douglas, PGE and other purchasers of the Project's output entered into a Settlement Endorsement Agreement (Agreement) that provides for the sale by Douglas of revenue bonds to fund the $13.5 million payment. 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 current 20.3% share of the Project's output will be reduced by approximately 1%. The effects of both the debt service requirement and the reduction in output were included in projected power costs in PGE's final 2005 RVM filing approved by the OPUC in December 2004.

For further information regarding the power purchase contracts on the mid-Columbia dams, 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 red uce 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 Clas s 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, 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 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, 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 orders remanding this matter to the OPUC. On August 31, 2004, the administrative law judge issued an 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 August 31, 2004 Order. On December 20, 2004, the URP and Class Action Plaintiffs filed an application with the OPUC for reconsideration of the OPUC's October 18, 2004 Order. On February 11, 2005, the OPUC denied reconsideration.

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 Rules of Civil Procedure, Potential Plaintiffs may not bring the suit until 30 days after the date of the Notice.

Management cannot predict the ultimate outcome of these 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 for a future reporting period. No reserves have been established by PGE for any amounts related to this issue.

Nuclear Decommissioning

PGE is continuing its decommissioning activities at the Trojan Plant under the plan approved by the NRC and EFSC; such activities are proceeding satisfactorily and within approved cost estimates. The steam generator, reactor containment vessel, and other major components have been removed and transported to a licensed low level radioactive waste disposal facility in Washington State for permanent storage. A license amendment for the Independent Spent Fuel Storage Installation (ISFSI), an interim dry storage facility that will house the nuclear fuel at the plant site until permanent storage is available, was approved by the NRC in 2002, with fuel loading completed in 2003. In December 2004, upon completion of final radiological surveys, PGE requested NRC termination of the Trojan Nuclear Plant Facility Operating License, which will remove the operating plant facility and site from regulation by the NRC. Spent fuel storage activities will continue to be subject to NRC regul ation until the storage installation is fully decommissioned, all nuclear fuel is removed from the site, and decontamination is completed. Remaining decommissioning activities consist of demolition of the existing structures and long-term operation and decommissioning of the ISFSI.

PGE has recorded an ARO for Trojan decommissioning of $96 million, measured at estimated fair value, as of December 31, 2004. The ARO estimate assumes that the majority of decommissioning activities will be completed by 2005, with costs extending through 2019. The plan anticipates final site restoration activities will begin in 2018 after PGE completes shipment of spent fuel to a USDOE facility. Decommissioning expenditures are estimated at $10 million for 2005, compared to $16 million in 2004.

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 President Bush signed the Yucca Mountain resolution into law on July 2002. Lawsuits have been filed objecting to the recommendation of Yucca Mountain as a nuclear waster repository. The USDOE, which must apply to the NRC for an operating license, did not submit an application before the December 1, 2004 deadline. Further delays may make it difficult for PGE to move its high-level radioactive waste, currently contained in the ISFSI, to permanent underground storage by 2018.

On January 6, 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 by the Standard Form Contract. The plaintiffs have paid the required assessment of $109 million and 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 and which will terminate in 2006. PGE is current on all payments.

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 Independent Spent Fuel Storage Installations. 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 April 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 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, 2004, 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 federally-mandated 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 has now begun to hear the numerous appeals. It has bifurcated appeals of the existing cases before it into two phases. The first will conside r arguments regarding jurisdictional issues and the permissible scope of refund liability, both in terms of the time frame for which refunds were ordered and the types of transactions subject to refund. The second phase will consider the issues relating to the refund methodology itself. PGE expects that the Court will establish additional phases as the 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. Under the new allocation methodology, 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.

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. In December 2004, the FERC requested comments regarding the manner in which such studies should be conducted and the principles that should control. PGE and numerous other parties filed comments and reply comments in January 2005. A decision by the FERC to adopt PGE's approach to these studies could reduce the Company's ultimate refund liability.

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). Interest has not yet been recorded by the Company. 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 de cision 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 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. PGE 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.

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 t hese 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 (IBEW) Local 125, 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, Oregon 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. Management cannot predict the ultimate outcome of this matter or estimate any potential loss.

Colstrip Plant - Royalty Claim

The Montana Department of Revenue, as agent for the Minerals Management Service of the U.S. Department of the Interior, issued two orders to Western Energy Co. (WECO) in 2002 and 2003. The orders asserted underpayment of royalties and taxes by WECO related to transportation of coal from the mine to Colstrip Units 3 and 4. WECO transports the coal under a Coal Transportation Agreement with the Colstrip Units 3 and 4 owners. PGE has a 20% ownership interest in Colstrip Units 3 and 4. WECO has appealed these orders and PGE is monitoring the process. Based upon its review of the Coal Transportation Agreement, the Colstrip Units 3 and 4 owners believe they have reasonable defenses in this matter.

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." Management believes that the Company's contribution to t he sediment contamination, if any, from the Harborton Substation site would qualify it as a de minimis Potentially Responsible Party.

The EPA is coordinating activities of natural resource agencies and the DEQ and in early 2002 requested and received signed "administrative orders of consent" from several Potentially Responsible Parties, voluntarily committing to further remedial investigations; PGE was not requested to sign, nor has it signed, such an order.

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.

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. Management cannot predict the ultimate outcome of this matter. However, PGE believes this matter will not have a material adverse impact on its financial statements.

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 required Colstrip Units 3 and 4 to submit for review and approval by the EPA an analysis and proposal for reducing emissions of nitrogen oxides to address visibility concerns if and when EPA promulgated certain requirements for nitrogen oxides. The EPA is asserting that regulations it promulgated in 1980 triggered the requirement. The EPA does not expressly seek penalties nor indicate what, if any, additional control technology requirements that it may require to be considered. PPL Montana, which has reported that it believes that the ACO is unfounded, is discussing the matter with the EPA.

In addition to the ACO, the EPA regional office that regulates plants in Montana has issued an information request with respect to the Colstrip plants. The regional office 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 Act. PPL Montana is in the process of responding to the information request.

A local Native American tribe has asserted that sulfur dioxide emissions from Colstrip Units 3 and 4 are affecting local tribal areas more than previously estimated. PPL Montana is working with the Montana Department of Environmental Quality to provide additional information to address this issue.

PPL Montana and EPA are discussing possible emission control and monitoring requirements involving all Colstrip units to address the issues discussed above.

New Accounting Standards

On December 21, 2004, the Financial Accounting Standards Board issued FASB Staff Position No. 109-1 (FSP 109-1), Application of FAS 109, Accounting for Income Taxes, to the Tax Deduction on Qualified Production Activities provided by the American Jobs Creation Act of 2004 (Act). For companies that pay federal income taxes on manufacturing activities in the United States, the Act provides a deduction from taxable income equal to a stipulated percentage of qualified income from domestic production activities (qualified production income or "QPI"). The deduction, which cannot exceed fifty percent of annual wages paid, is phased in as follows: three percent of QPI in 2005-2006, six percent in 2007-2009, and nine percent in 2010 and thereafter. Eligible activity, as defined in the Act, includes oil and gas extraction and electricity and water production (excluding transmission and distribution). Under FSP 109-1, tax deductions on QPI activities are to be treated as special deductions un der FAS 109. The application of FSP 109-1 is required in financial statements of entities that have QPI and any effect to deferred tax assets from the reduction of future taxable income for periods ending after the December 21, 2004 effective date. The adoption of FSP 109-1 did not have any effect to PGE's deferred tax assets as of December 31, 2004. PGE is currently evaluating the impact of the application of FSP 109-1 to the Company's electric generation activities.

In December 2004, SFAS No. 153 (SFAS 153), Exchanges of Nonmonetary Assets, Amendment of Accounting Principles Board Opinion No. 29, Accounting for Nonmonetary Transactions (APB 29), was issued. SFAS 153 requires that nonmonetary asset exchanges be recorded and measured at the fair value of the assets exchanged, with certain exceptions. SFAS 153 amends APB 29 to eliminate the fair-value exception for nonmonetary exchanges of similar productive assets and replaces it with a general exception for nonmonetary exchanges that do not have commercial substance. The application of SFAS 153 is required in financial statements of entities that have nonmonetary asset exchanges in fiscal periods beginning after June 15, 2005. PGE is evaluating the impact of the application of SFAS 153 with respect to nonmonetary asset exchanges.

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," "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, as applicable, 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 related to Enron and certain of its subsidiaries' filings to initiate bankruptcy proceedings under Chapter 11 of the federal Bankruptcy Code (PGE is not included in the filing);
- events related to Enron's bankruptcy proceedings;
- events related to Enron's proposed sale of PGE to Oregon Electric;
- 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;
- 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;
- 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; and,
- general political, economic, and financial market conditions.

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 exchange rates, and interest rates. 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. In addition, Company policy allows the use of these instruments for trading purposes, which may expose the Company to market risks resulting from adverse changes in commodity prices. Under EITF 02-3, gains and losses on such instruments are recognized on a net basis within Operating revenues on PGE's income statement. 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 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 trading portfolio in 2004 were $0.1 million, $0.2 million, and zero, respectively, in 2003 were $0.1 million, $0.4 million, and zero, respectively, and i n 2002 were $0.1 million, $0.4 million, and zero, respectively. The instances of zero value at risk occur when there are no open positions in the trading portfolio. The average, high, and low value at risk on the non-trading portfolio 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. For 2002, the value at risk on the non-trading portfolio is not meaningful since the majority of the portfolio was effectively accounted for on an accrual or settlements basis.

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, primarily 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, 2004, 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. Foreign currency risk in PGE's trading portfolio is immaterial to the Company's consolidated financial statements and is not expected to change materially in the near future.

Interest Rate Risk

Although PGE has no short-term debt outstanding at December 31, 2004, the Company is typically exposed to risk resulting from changes in interest rates on variable rate short-term borrowings. 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							After
	Value	Total	2005	2006	2007	2008	2009	2009
First Mortgage Bonds	$ 597	$538	$18	$ -	$50	$ -	$ -	$470
Pollution Control Revenue Bonds	195	194	-	-	-	-	-	194
Other	213	190	12	11	20	-	-	147
Total	$1,005	$922	$30	$11	$70	$ -	$ -	$811

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 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.

Credit risk with respect to trade accounts receivable from retail electricity sales is limited. The large number of customers and diversified customer base of residential, commercial, and industrial customers, combined with the Company's ability to discontinue service, significantly reduces credit risk. Estimated provisions for uncollectible accounts receivable related to retail electricity sales are provided for credit risk. At December 31, 2004, the likelihood of significant losses associated with credit risk in trade accounts receivable is remote.

The following tables present PGE's credit exposure for commodity non-trading and trading activities and their subsequent maturity as of December 31, 2004. The tables reflect 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	2005	2006	2007	2008	2009	After 2009
Investment Grade	$ 88	92%	$ 9	$23	$14	$10	$ 9	$ 9	$23
Non-Investment Grade	7	7%	5	5	2	-	-	-	-
Internally Rated -Investment Grade	1	1%	-	1	-	-	-	-	-
Total	$ 96	100%	$ 14	$29	$16	$10	$ 9	$ 9	$23

Trading Activities

(Dollars in millions)				Maturity of Credit Risk Exposure					
Rating	Credit Risk Before Collateral	Percentage of Total Exposure	Credit Collateral	2005	2006	2007	2008	2009	After 2009
Investment Grade	$ 3	100%	$ -	$ 3	$ -	$ -	$ -	$ -	$ -

Investment grade includes 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.

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Risk Management Committee

PGE has a Risk Management Committee (RMC) which is responsible for the oversight of commodity position and price risk, foreign currency risk, and credit risk related to the Company's energy portfolio management activities. The RMC consists of officers and Company representatives with responsibility for risk management, finance and accounting, legal, rates and regulatory affairs, power operations, and generation operations. The RMC approves policies and procedures, establishes limits subject to Enron approval, and monitors compliance and risk exposure 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.

Deloitte & Touche LLP was engaged to audit the 2004 and 2003 financial statements of PGE and issue a report thereon. PricewaterhouseCoopers LLP was engaged to audit the 2002 financial statements of PGE and issue a report thereon. Their audits included developing an overall understanding of PGE's accounting systems, procedures, and internal controls, and conducting tests and other auditing procedures sufficient to support their opinions on the financial statements. The independent auditors' reports appear in this report.

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. The independent auditors have direct access to the Audit Committee, and they meet with the committee from time to time, with and without financial management present, to discuss accounting, auditing and financial reporting matters.

Report of Independent Registered Public Accounting Firm

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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, 2004 and 2003, and the related consolidated statements of income, retained earnings, comprehensive income, and cash flows for the years then ended. Our audit also included the financial statement schedule for the years ended December 31, 2004 and 2003 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. An audit includes 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, 2004 and 2003, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule for the years ended December 31, 2004 and 2003, 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.

Deloitte & Touche LLP

Portland, Oregon

March 10, 2005

Report of Independent Registered Public Accounting Firm

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

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a) present fairly, in all material respects, the results of operations and cash flows of Portland General Electric Company and its subsidiaries (the "Company") for the year in the period ended December 31, 2002 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits. We conducted our audits o f these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, the Company changed its method of reporting for contracts involved in energy trading and risk management activities in the third quarter of 2002.

PricewaterhouseCoopers LLP

Portland, Oregon

March 11, 2003

Portland General Electric Company and Subsidiaries			
Consolidated Statements of Income			
For the Years Ended December 31	**2004**	**2003**	**2002**
	(In Millions)		
Operating Revenues	$1,454	$1,752	$1,855
Operating Expenses			
Purchased power and fuel	667	1,028	1,157
Production and distribution	127	117	118
Administrative and other	148	148	147
Depreciation and amortization	233	213	161
Taxes other than income taxes	72	72	69
Income taxes	57	50	68
	1,304	1,628	1,720
Net Operating Income	150	124	135
Other Income (Deductions)			
Miscellaneous	8	5	(8)
Income taxes	3	6	10
	11	11	2
Interest Charges			
Interest on long-term debt and other	69	79	67
Interest on short-term borrowings	-	-	4
	69	79	71
Net Income before cumulative effect of a change in accounting principle	92	56	66
Cumulative effect of a change in accounting principle, net of related taxes of $(1) in 2003	-	2	-
Net Income	92	58	66
Preferred Dividend Requirement	-	1	2
Income Available for Common Stock	$ 92	$ 57	$ 64

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	2004	2003	2002
	(In Millions)		
Balance at Beginning of Year	$ 545	$ 488	$ 451
Net Income	92	58	66
	637	546	517
Dividends Declared			
Common stock (non-cash dividend in 2002)	-	-	27
Preferred stock	-	1	2
	-	1	29
Balance at End of Year	$ 637	$ 545	$ 488

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	2004	2003	2002
	(In Millions)		
Accumulated other comprehensive income (loss) - Beginning of Year			
Unrealized gain (loss) on derivatives classified as cash flow hedges	$ 2	$ 3	$ -
Minimum pension liability adjustment	(4)	(3)	(2)
Total	$ (2)	$ -	$ (2)
Net Income	$ 92	$ 58	$ 66
Other comprehensive income, net of tax:			
Other unrealized holding gains (losses) arising during the period, net of related taxes of $(8) in 2004, $(5) in 2003, and $(4) in 2002	12	9	7
Reclassification adjustment for contract settlements included in net income, net of related taxes of $4 in 2004, $1 in 2003, and $(1) in 2002	(6)	(3)	1
Reclassification adjustment in net income due to discontinuance of cash flow hedges, net of related taxes of $6	-	(9)	-
Reclassification of unrealized gains (losses) to SFAS No. 71 regulatory (liability) asset, net of related taxes of $6 in 2004, $(2) in 2003, and $3 in 2002	(10)	2	(5)
Total - Unrealized gains (losses) on derivatives classified as cash flow hedges	(4)	(1)	3

Minimum pension liability adjustment	-	(1)	(1)
Total Other comprehensive income (loss)	(4)	(2)	2
Comprehensive income	$ 88	$ 56	$ 68
Accumulated other comprehensive income (loss) - End 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)	$ -

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

Portland General Electric Company and Subsidiaries

Consolidated Balance Sheets

At December 31	2004	2003
	(In Millions)	
Assets		
Electric Utility Plant - Original Cost		
Utility plant	$ 3,992	$ 3,834
Accumulated depreciation	(1,717)	(1,633)
	2,275	2,201
Other Property and Investments		
Receivable from parent (less allowance for uncollectible accounts of $0 and $73)	-	-
Nuclear decommissioning trust, at market value	22	35
Non-qualified benefit plan trust	64	67
Miscellaneous	30	38
	116	140
Current Assets		
Cash and cash equivalents	204	109
Accounts and notes receivable (less allowance for uncollectible accounts of $50 and $51)	170	223
Unbilled revenues	80	72
Assets from price risk management activities	77	66
Inventories, at average cost	48	45
Prepayments and other	113	97
	692	612
Deferred Charges		
Regulatory assets	295	387
Miscellaneous	25	32
	320	419
	$ 3,403	$ 3,372
Capitalization and Liabilities		
Capitalization		
Common stock equity		
Common stock, $3.75 par value per share, 100,000,000 shares	$ 160	$ 160

authorized, 42,758,877 shares outstanding		
Other paid-in capital - net	481	481
Retained earnings	637	545
Accumulated other comprehensive income (loss):		
Unrealized gain (loss) on derivatives classified as cash flow hedges	(2)	2
Minimum pension liability adjustment	(4)	(4)
Limited voting junior preferred stock	-	-
Long-term obligations	892	927
	2,164	2,111
Commitments and Contingencies (see Notes)		
Current Liabilities		
Long-term debt due within one year	30	56
Accounts payable and other accruals	182	230
Liabilities from price risk management activities	38	44
Customer deposits	18	5
Accrued interest	19	20
Accrued taxes	37	51
Deferred income taxes	15	8
	339	414
Other		
Deferred income taxes	308	349
Deferred investment tax credits	13	16
Trojan asset retirement obligation	96	104
Accumulated asset retirement obligation	16	17
Regulatory liabilities:		
Accumulated asset retirement removal costs	286	230
Other	74	27
Non-qualified benefit plan liabilities	70	66
Miscellaneous	37	38
	900	847
	$ 3,403	$ 3,372
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	**2004**	**2003**	**2002**
	(In Millions)		
Cash Flows From Operating Activities:			
Reconciliation of net income to net cash provided by operating activities			

Net income	$ 92	$ 58	$ 66
Non-cash items included in net income:			
Cumulative effect of a change in accounting principle,			
net of tax	-	(2)	-
Depreciation and amortization	233	213	161
Deferred income taxes	(13)	(22)	55
Net assets from price risk management activities	(7)	(30)	(11)
Power cost adjustment	40	51	(19)
Other non-cash income and expenses (net)	16	19	(16)
Changes in working capital:			
Net margin deposit activity	13	-	89
Decrease in receivables	43	9	6
Increase (Decrease) in payables	(61)	21	1
Other working capital items - net	(22)	(6)	(23)
Other - net	6	(4)	(4)
Net Cash Provided by Operating Activities	340	307	305
Cash Flows From Investing Activities:			
Capital expenditures	(194)	(167)	(165)
Other - net	10	(11)	19
Net Cash Used in Investing Activities	(184)	(178)	(146)
Cash Flows From Financing Activities:			
Net decrease in short-term borrowings	-	-	(174)
Repayment of long-term debt	(61)	(402)	(174)
Issuance of long-term debt	-	342	250
Debt issue costs	-	(7)	(14)
Preferred stock retired	-	(3)	(2)
Dividends paid	-	(1)	(2)
Net Cash Used in Financing Activities	(61)	(71)	(116)
Increase in Cash and Cash Equivalents	95	58	43
Cash and Cash Equivalents, Beginning of Period	109	51	8
Cash and Cash Equivalents, End of Period	$ 204	$ 109	$ 51
Supplemental disclosures of cash flow information			
Cash paid during the period:			
Interest, net of amounts capitalized	$ 62	$ 67	$ 62
Income taxes	83	39	2
Non-cash investing activity:			
	-	-	28

Sale of 33.33% interest in Pelton Round Butte hydroelectric project			
Non-cash financing activity:			
Dividend to parent	-	-	27

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

Portland General Electric Company and Subsidiaries

Notes to Consolidated Financial Statements

Nature of Operations

On July 2, 1997, Portland General Corporation (PGC), the former parent of Portland General Electric Company (PGE or the Company), merged with Enron Corp. (Enron), with Enron continuing in existence as the surviving corporation. PGE is currently a wholly owned subsidiary of Enron and subject to control by Enron. 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 th e end of 2004, PGE's service area population was approximately 1.5 million, comprising about 43% of the state's population. The Company served approximately 767,000 retail customers at December 31, 2004.

On December 2, 2001, Enron, along with certain of its subsidiaries, filed to initiate bankruptcy proceedings under Chapter 11 of the federal Bankruptcy Code; the related Chapter 11 Plan became effective on November 17, 2004. PGE is not included in the filing.

On November 18, 2003, Enron and Oregon Electric Utility Company, LLC (Oregon Electric), a newly-formed Oregon limited liability company financially backed primarily by investment funds managed by Texas Pacific Group, entered into a definitive agreement under which Enron will sell all of the issued and outstanding common stock of PGE to Oregon Electric. The transaction, which has been approved by the Bankruptcy Court in Enron's Chapter 11 bankruptcy proceedings, requires approval of the Oregon Public Utility Commission (OPUC), the Federal Energy Regulatory Commission (FERC), the Securities and Exchange Commission (SEC), and certain other regulatory agencies. On March 10, 2005, the OPUC issued Order No. 05-114, in which it denied Oregon Electric's application to purchase PGE. Enron and Oregon Electric have stated that they are carefully reviewing the Order and evaluating their next steps. See Note 15, Enron Bankruptcy, 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, including tax 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

Revenues are recognized when monthly billings are made for energy sold to customers and delivered to those customers that purchase their energy from 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. 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) Benefits passed directly to PGE's residential and small farm customers pursuant to an agreement with the Bonneville Power Administration (BPA) that provides cash benefits and power from BPA over a ten-year period that began October 1, 2001; 2) Amounts deferred under the Company's power cost adjustment mechanisms (described under "Power Cost Adjustment Mechanisms" and "Regulatory Assets and Liabilities" in this Note), as well as amortization of such amounts as recovery is made from customers; 3) 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, 4) Provisions related to wholesale accounts receivable and unsettl ed positions (described under "Revenues" in this Note).

Price Risk Management

PGE engages in price risk management activities in its electric business for both non-trading and trading purposes, 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, 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, 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 reverse d.

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

Realized and unrealized gains and losses associated with energy trading 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, which became effective in the third quarter of 2002. Such gains and losses are included within Operating Revenues on the Statement of Income.

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

Margin Deposits on Wholesale Activities

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 and 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 Customer deposits 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):

	2004		2003

Production	$1,376		$1,359
Transmission	283		277
Distribution	1,856		1,752
General	243		241
Intangible	120		116
Construction Work in Progress	114		89
Total	$3,992		$3,834

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 4.5% in 2004, 4.6% in 2003, and 4.4% in 2002. Estimated asset retirement removal costs included in depreciation expense were $61 million, $58 million, and $62 million in 2004, 2003, and 2002, 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 was approved by the OPUC and incorporated in its August 2001 general rate order.

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 2004, 2003, and 2002 was $14 million, $13 million, and $8 million, respectively, and is estimated at $12 million for 2005, $15 million for 2006, $14 million for 2007, and $11 million for both 2008 and 2009. Accumulated amortization was $67 million and $53 million at December 31, 2004 and December 31, 2003, 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 2004, 2003, and 2002 were 9.0%, 9.0%, and 5.0%, respectively. AFDC from borrowed funds was $3 million in 2004, 2003 and 2002. AFDC from equity funds was $6 million in 2004, $4 million in 2003, and $2 million in 2002.

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, 2004 and 2003 were $19 million and $23 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. For further information, see Note 13, Rela ted Party Transactions, and Note 15, Enron Bankruptcy.

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 $20 million at December 31, 2004 and $21 million at December 31, 2003. 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 $44 million at December 31,&nbs p;2004 and $46 million at December 31, 2003.

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):

	2004		2003
Coal	$ 8		$ 6
Fuel oil	11		11
Natural gas	3		2
Materials and supplies	24		24
Unallocated stores account	2		2
Total	$48		$45

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Trojan Decommissioning and Transition Costs

Trojan decommissioning costs consist of those expenditures related to the decommissioning of the Trojan Nuclear Plant. Transition costs associated with operating and maintaining the spent fuel pool and securing the plant ended in September 2003 with the completion of the transfer of spent fuel to dry storage. 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. 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.

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):

		2004		2003
Regulatory assets:				
	Trojan decommissioning costs	$ 74		$ 82
	Income taxes recoverable	92		113
	Prior tax benefits recoverable	10		19
	Debt reacquisition costs	23		24
	Conservation investments - secured	19		29
	Energy efficiency programs	10		21
	Power cost adjustment mechanisms	19		58
	Regulatory restructuring costs	20		23
	Beaver 8	11		-
	Pelton Round Butte tax benefits recoverable	3		5
	Miscellaneous	14		13
	Total	$295		$387

Regulatory liabilities:		
Asset retirement obligations	$ 18	$ 14
Accumulated asset retirement removal costs	286	230
Price risk management	45	8
Information technology costs	3	2
Miscellaneous	8	3
Total	$360	$257

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 recoverable 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, are recovered from retail customers by a separate supplemental tariff schedule, with complete recovery expected by the end of 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 mechanisms - 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 balance, which is being recovered over a 3 1/2-year period that began April 1, 2002, was $19 million at December 31, 2004 and $48 million at December 31, 2003 (including accrued interest).

In its August 2001 general rate order, the OPUC approved a power cost adjustment mechanism for the period October 2001 through December 2002. Under this mechanism, PGE deferred for recovery from customers the difference between actual net variable power costs and the amount used to establish base energy rates, as well as the difference between actual energy revenues and a pre-determined base. The deferred amount was recovered over a one-year period (2003) from large industrial customers and over a two-year period (2003-2004) from all other customer classes. The deferred balance was zero at December 31, 2004 and $10 million at December 31, 2003 (including accrued interest).

PGE did not have power cost adjustment mechanisms for 2003 and 2004 and currently has none in place for 2005.

Regulatory restructuring costs - The OPUC has 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 $5 million at December 31, 2004. 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 $15 million at December 31, 2004.

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 installed at Beaver (referred to as Beaver 8) 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 will be included in rate base in PGE's next general rate case.

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 is being made 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 either the normal purchase and normal sale exception or for hedge accounting to be recorded in earnings 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, 2004 and 2003 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, $4 million, and $8 million were recorded in 2004, 2003, and 2002, respectively, 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 2005. A $4 million annual deferral will continue until new base rates are established.

Recovery/refund period - As of December 31, 2004, 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 7 years.

New Accounting Standard

PGE adopted SFAS No. 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits (Revised 2003)," which requires additional disclosures about assets, obligations, cash flows, and net periodic benefit cost of defined benefit pension plans and other postretirement benefit plans. The additional disclosures are contained in Note 2, Employee Benefits.

Note 2 - Employee Benefits

Pension and Other Post-Retirement Plans

PGE sponsors a non-contributory defined benefit pension plan in which Portland General Holdings, Inc. (PGH) and its subsidiaries have participated. Substantially all pension plan members are current or former PGE employees. The pension plan assets are held in a trust.

PGH is currently in bankruptcy (see Note 13, Related Party Transactions) and will likely be dissolved. Its parent company, Enron, is also in bankruptcy. PGE will be the sole surviving member of the controlled group, and is jointly and severally liable for ongoing funding contributions to the pension plan. Accordingly, effective December 31, 2004, PGE disclosures include 100% of plan liabilities offset by 100% of plan assets. In prior years, some assets and liabilities were attributed to PGH and thus not disclosed by PGE. PGE has included an additional $3 million of benefit obligations and $11 million of plan assets in the table below as a result of the expected PGH dissolution. PGE also recorded the total net periodic pension benefit income in 2004, including an amount that would have formerly been attributed to PGH.

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 $22 million as of December 31, 2004 and 2003 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 both 2004 and 2003. In addition, recognized gains on trust assets of $1 million and $2 million for 2004 a nd 2003, respectively, and a recognized loss on trust assets of $1 million for 2002 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.

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. In 2004, PGE established Health Retirement Accounts (HRAs) for its employees under which the Company will make contributions to a trust to provide for claims by retirees for qualified medical costs. In the 2004 bargaining unit agreement, employees who had an accumulated sick time balance will be able, upon retirement, to submit claims to the HRA for qualified medical expenses up to the value of the sick time available at that time. The Company also granted a fixed dollar amount for all current non-bargaining active em ployees that will be available upon retirement for claims for qualified medical expenses. As a result of the HRAs the benefit obligation increased $6 million in 2004.

The measurement date for these plans is December 31. PGE does not expect to make contributions to the pension plan, SERP, or post-retirement health and life insurance plans during 2005; contributions to the HRAs are expected to be minimal.

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		Non-Qualified			
	Pension Plan		Benefit Plans		Other Benefits	
	2004	2003	2004	2003	2004	2003
Reconciliation of benefit obligation:						
Obligation at January 1	$ 400	$ 353	$ 21	$ 19	$ 45	$ 42
Service cost	12	11	-	-	1	1
Interest cost	24	23	2	1	3	3

Plan amendments	2	-	-	-	1	-
New plans	-	-	-	-	6	-
Participants' contributions	-	-	-	-	1	1
Actuarial loss	29	30	1	3	2	1
Benefit payments	(17)	(17)	(2)	(2)	(4)	(3)
Obligation at December 31	$ 450	$ 400	$ 22	$ 21	$ 55	$ 45
Reconciliation of fair value of plan assets:						
Fair value of plan assets at January 1	$ 415	$ 337	$ 22	$ 21	$ 26	$ 22
Actual return on plan assets	54	95	2	2	3	6
Company contributions	-	-	-	1	-	-
Participants' contributions	-	-	-	-	1	1
Benefit payments	(17)	(17)	(2)	(2)	(4)	(3)
Fair value of plan assets at December 31	$ 452	$ 415	$ 22	$ 22	$ 26	$ 26
Funded status:						
Funded (unfunded) status at December 31 (*)	$ 2	$ 15	$ -	$ 1	$ (29)	$ (19)
Unrecognized transition (asset)/liability	-	(2)	-	-	2	2
Unrecognized prior service cost	6	5	1	1	8	2
Unrecognized gain	70	55	2	2	10	9
Prepaid pension cost (liability)	$ 78	$ 73	$ 3	$ 4	$ (9)	$ (6)
Accumulated benefit obligation	$ 394	$ 347	$ 19	$ 17	N/A	N/A
Amounts recognized in the Balance Sheet consist of:						
Prepaid benefit cost	$ 78	$ 73	$ 9	$ 10	$ (9)	$ (6)
Accumulated other comprehensive income	-	-	(6)	(6)	-	-
Net amount recognized	$ 78	$ 73	$ 3	$ 4	$ (9)	$ (6)
Assumptions:						
Discount rate used to calculate benefit obligation	5.75%	6.25%	5.75%	6.25%	5.75%	6.25%
Weighted average rate of increase in future comcompensation levels						
compensation levels	4.48%	4.75%	N/A	5.75%	5.30%	5.30%
Long-term rate of return on assets	9.00%	9.00%	N/A	N/A	8.63%	8.61%

	Defined Benefit Pension Plan			**Non-Qualified Benefit Plans**			**Other Benefits**		
	2004	**2003**	**2002**	**2004**	**2003**	**2002**	**2004**	**2003**	**2002**
Components of net periodic benefit cost:									
Service cost	$ 12	$ 11	$ 9	$ -	$ -	$ -	$ 1	$ 1	$ 1
Interest cost on benefit obligation	24	23	21	1	2	2	3	3	3
Expected return on plan assets	(40)	(39)	(39)	-	-	-	(2)	(1)	(2)
Amortization of transition asset	(2)	(2)	(2)	-	-	-	1	-	-
Amortization of prior service cost	2	1	1	1	-	-	-	-	-
Recognized (gain) loss	-	-	(3)	(1)	(2)	1	-	1	-
Net periodic benefit cost (income)	$ (4)	$ (6)	$ (13)	$ 1	$ -	$ 3	$ 3	$ 4	$ 2

(*) Due to a decline in the discount rate during 2004, the estimated obligation for the pension plan and for other benefits increased. In addition, the fair value of assets in the pension trust increased, reflecting the general upturn in the equity markets. The impact of changing financial market conditions resulted in a total fair value of pension plan assets that was $2 million higher than the projected benefit obligation at December 31, 2004.

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					
	2005	2006	2007	2008	2009	2010 - 2014
Pension Plan Payments	$18	$17	$17	$18	$19	$ 86
Non-Qualified Plan Payments	2	1	2	1	1	8
Other Plan Payments	3	3	4	4	4	22
Total	$23	$21	$23	$23	$24	$116

The plan develops 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 10% annual rate of increase in the per capita cost of covered health care benefits is assumed for 2005. 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, 2004 and 2003 and the target allocation for 2005, by asset category, are as follows:

	Percentage of Plan Assets		
Asset Category	December 31		Target Allocation
	2004	2003	2005
Equity Securities	70%	72%	67%
Debt Securities	30%	28%	33%
Total	100%	100%	100%

The asset allocation for the Non-Qualified Benefit Plans at December 31, 2004 and 2003 are as follows:

	Percentage of Plan Assets	
Asset Category	December 31	
	2004	2003
Equity Securities	26%	30%
Debt Securities	26%	28%
TOLI Policies	48%	42%
Total	100%	100%

An insurable interest in the respective employee is required for investment in TOLI policies. PGE does not establish target allocations between the TOLI assets and the remaining investments. The 2005 target allocations between equity and debt securities is approximately 50% - 50%.

The asset allocation for the Other Benefit Plans at December 31, 2004 and 2003, and the target allocation for 2005, by asset category, are as follows:

		Percentage of Plan Assets						
Asset Category		December 31				Target Allocation		
		2004		2003			2005	
Equity Securities		69%		69%			68%	
Debt Securities		31%		31%			32%	
Total		100%		100%			100%	

The Plans' investment policy calls 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 they may defer a portion of their pay. Obligations for the MDCP were $51 million and $49 million at December 31, 2004 and 2003, 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 $40 million and $41 million at December 31, 2004 and 2003, respectively. For 2004 and 2003, unrealized gains in marketable securities were $1 million and $2 million, respectively.

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 both December 31, 2004 and 2003.

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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 $12 million in 2004 and $10 million in both 2003 and 2002.

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):

			2004		**2003**		**2002**
Income Tax Expense							
Current:							
	Federal		$59		$59		$ 5
	State and local		8		7		-
			67		66		5
Deferred:							

	Federal	(8)		(19)		46
	State and local	(2)		-		11
		(10)		(19)		57
Investment tax credit adjustments		(3)		(3)		(4)
Total income tax expense before cumulative						
	effect of a change in accounting principle	$54		$44		$58
Income tax expense allocated to:						
	Operations	$57		$50		$68
	Other income and deductions	(3)		(6)		(10)
Total income tax expense before cumulative						
	effect of a change in accounting principle	$54		$44		$58
Effective Tax Rate Computation:						
Computed tax based on statutory federal						
	income tax rate (35%) applied to income					
	Before income taxes	$51		$35		$44
Flow through depreciation		9		7		8
State and local taxes - net of federal tax benefit		5		4		6
Investment tax credits		(3)		(3)		(4)
Excess deferred taxes		(1)		(1)		(1)
Adjustments for previously-recorded taxes		(3)		-		-
Other		(4)		2		5
Total income tax expense before cumulative effect of a change in accounting principle		$54		$44		$58
Effective tax rate		37.0%		44.0%		46.8%

As of December 31, 2004 and 2003, the significant components of PGE's deferred income tax assets and liabilities were as follows (in millions):

		2004		2003
Deferred income tax assets				
Depreciation and amortization	$	37	$	33
Employee benefits		31		28
Allowance for uncollectible accounts		20		20

Land reclamation costs		8		8
Regulatory liabilities				
Asset retirement removal costs		113		91
Other		9		1
Other		22		18
Total deferred income tax assets		240		199
Deferred income tax liabilities				
Depreciation and amortization		465		440
Employee benefits		24		22
Property taxes		5		5
Price risk management		4		6
Regulatory assets				
Prior tax benefits recoverable		4		7
Debt reacquisition costs		9		7
Conservation investments		7		11
Energy efficiency programs		12		12
Power cost adjustment		7		23
Miscellaneous		13		11
Other		13		12
Total deferred income tax liabilities		563		556
Net deferred income taxes	$	323	$	357
Classification of net deferred income taxes				
Included in current liabilities	$	15	$	8
Included in non current liabilities		308		349
Net deferred income taxes	$	323	$	357

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

	Common Stock		Cumulative Preferred (*)		Limited Voting Junior Preferred		
	Number of Shares	$3.75 Par Value	Number of Shares	No Par Value	Number of Shares	$1.00 Par Value	Paid-in Capital
(Dollars in Millions)							
December 31, 2002	42,758,877	$160	279,727	$28	1	-	$481
December 31, 2003	42,758,877	160	-	-	1	-	481
December 31, 2004	42,758,877	160	-	-	1	-	481

(*) SFAS No. 150, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity, requires financial instruments that are mandatorily redeemable at a fixed amount and on specified or determinable dates to be reclassified as liabilities on the balance sheet. Reclassification of prior period amounts is not permitted. As required by SFAS No. 150, PGE's outstanding preferred stock was reclassified to liabilities on July 1, 2003. See Note 5, Credit Facilities and Debt, for further information.

Limited Voting Junior Preferred Stock

On September 30, 2002, a single share of a new class of Limited Voting Junior Preferred Stock (Stock) was issued by PGE to an independent party. The new class of stock, created by an amendment to PGE's Articles of Incorporation, was issued following approval by the Bankruptcy Court, Debtor-in-Possession lenders, the OPUC, and PGE's board of directors.

The Stock has a par value of $1.00, no dividend, a liquidation preference to the Common Stock as to par value but junior to existing preferred stock, an optional redemption right, and certain restrictions on transfer. The Stock 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 Stock. The consent of the holder of the share of Stock will not be required if the reason for the Bankruptcy is to implement a transaction pursuant to which all of PGE's debt will be paid or assumed without impairment.

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). In addition, the terms of PGE's two revolving credit facilities allow for the payment of cash dividends not to exceed $240 million and, beginning on January 1, 2005, permit the payment of additional dividends in an aggregate amount not exceeding PGE's cumulative net income for each quarterly period. Management believes that, at December 31, 2004, the Company has the ability to pay dividends, notwithstanding these restrictions.

Note 5 - Credit Facilities and Debt

At December 31, 2004, PGE had two revolving credit facilities with a group of commercial banks totaling $150 million, consisting of a $50 million 364-day facility and a $100 million three-year facility. These facilities, both of which are unsecured, replaced a $150 million 364-day secured revolving credit facility that expired in May 2004. The current facilities provide for borrowings at a variable interest rate and require quarterly facility fees based on PGE's unsecured credit rating. The 364-day facility contains a "term out" option that would allow the Company to extend the final maturity of amounts outstanding at the facility expiration date for up to one additional year. Under the three-year credit facility, PGE has the option to issue letters of credit, in addition to borrowings, totaling up to the $100 million. At December 31, 2004, the Company had utilized approximately $2 million in letters of credit.

The facility agreements provide for termination of the banks' obligation, and the full repayment of any outstanding balances, in the event of the sale of the Company's common stock to Oregon Electric or other changes in control, as defined in the agreements. The facilities allow PGE to pay cash dividends on common stock, subject to certain restrictions. Each facility contains material adverse effect clauses and financial covenants that limit consolidated indebtedness, as defined in the facilities, to 60% of total capitalization. In addition, the three-year facility requires that PGE maintain an interest coverage ratio, as defined in the facility, of not less than 3.00:1. At December 31, 2004, PGE was in compliance with these covenants.

PGE is evaluating alternatives for the replacement of its 364-day credit facility upon its May 23, 2005 expiration date, including the issuance of First Mortgage Bonds and/or new revolving credit facilities. Management believes that its existing lines of credit and access to the commercial paper market and cash from operations provide the Company with sufficient liquidity to meet its day-to-day cash requirements. As of December 31, 2004, the Company has sufficient capacity under its Indenture of Mortgage to issue additional First Mortgage Bonds for this purpose.

PGE had no short-term borrowings in 2003 or 2004.

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:		2004		2003
	(In Millions)			
First Mortgage Bonds				
Maturing 2005 - 2007 (7.15% - 9.07%) (a)	$	68	$	113
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
		538		583
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				
8.25% Junior Subordinated Deferrable Interest Debentures,				
due December 31, 2035 (b)		-		5
6.91% Conservation Bonds maturing monthly to 2006 (a)		20		29
7.875% Notes due March 15, 2010		149		149
7.75% Series Cumulative Preferred Stock (a) (c)		22		25
Unamortized debt discount		(1)		(2)
		190		206
		922		983
Long-term debt due within one year (a)		(30)		(56)
Total long-term debt	$	892	$	927

(a) Due within one year; consists of $18 million of 9.07% First Mortgage Bonds, $10 million of Conservation Bonds, and $2 million of 7.75% Series Cumulative Preferred Stock.

(b) The $5 million of 8.25% Junior Subordinated Deferrable Interest Debentures, due December 31, 2035, were redeemed on June 30, 2004. Pursuant to this redemption, PGE filed on June 30, 2004 to terminate registration of these securities under the Securities Exchange Act of 1934. PGE has de-listed from the New York Stock Exchange and is no longer listed on any stock exchange.

(c) 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 2004, 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, 2004, there were 219,727 shares outstanding.

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

	2005	2006	2007	2008	2009	Thereafter	Total
Debt							
Maturities	$30	$11	$70	$ -	$ -	$811	$922

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.

Investment in Debt Securities - In 2004, PGE invested $10 million in municipal bonds, maturing in 2025, with interest rates that reset every twenty-eight days through a "Dutch" auction process. The securities are classified as trading and recorded as "Prepayments and other" in the Current Asset section of PGE's balance sheet. The carrying amount of these securities approximates fair value. There were no unrealized or realized gains or losses recorded for these securities in 2004.

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):

	2004	2003

	2004		2003	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt including current maturities	$922	$1,005	$983	$1,044

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. As of December 31, 2004, these agreements require net payments of approximately $26 million in 2005, $15 million in both 2006 and 2007, $13 million in 2008, $11 million in 2009, and $37 million over the remaining years of the contracts, which expire at varying dates from 2005 to 2015.

Purchase Commitments

Certain commitments have been made for capital and other purchases for 2005 and beyond. Such commitments total $269 million as of December 31, 2004, reflecting payments of $87 million in 2005, $168 million in 2006, and $14 million in 2007. Such commitments include those related to construction of Port Westward, 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 $16 million for 2005 and $4 million annually from 2006 through 2014.

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, 2004	$383	$180	$182	$143	$ 24
PGE's current share of:					
Output	12.0%	13.9%	18.7%	20.3%	100%
Net capability (megawatts)	136	104	133	137	36
PGE's annual cost, including debt service:					
2004	$ 8	$ 4	$ 6	$ 6	$ 5
2003	9	4	7	7	5
2002	8	4	8	6	4
Contract expiration date	2011	2005	2009	2018	2017

PGE's share of debt service costs, excluding interest, is approximately $7 million in 2005, $6 million annually in 2006, 2007, and 2008, and $7 million in 2009. Total minimum payments through the remainder of the contracts are estimated at $37 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 agreements, which are subject to FERC approval, are effective upon expiration of the current contracts 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 2003, the Colville Confederated Tribes (Colville Tribe) presented a claim to Douglas County PUD (Douglas) based upon alleged annual charges for the Wells Hydroelectric Project (Project) for the use of Colville tribal lands. The Colville Tribe claimed that annual charges would also be due for periods into the future. PGE purchases 20.3% of the power generated by the Wells Project. In November 2004, Douglas and the Colville Tribe entered into a settlement that resolved all the Colville Tribe's claims. The settlement, which was approved by the FERC in February 2005, will impact the quantity and price of future output purchased by PGE. It requires that Douglas pay a lump sum of $13.5 million, convey certain real property, and allocate (at cost) 4.5% of the Project's output to the Colville Tribe. The Colville Tribe's allocation of the Project's output will increase to 5.5% for years after 2018 and continue for the life of the Project. Also in November 2004, Douglas, PGE and other p urchasers of the Project's output entered into a Settlement Endorsement Agreement (Agreement) that provides for the sale by Douglas of revenue bonds to fund the $13.5 million payment. 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 current 20.3% share of the Project's output will be reduced by approximately 1%. The effects of both the debt service requirement and the reduction in output were included in projected power costs in PGE's final 2005 RVM filing approved by the OPUC in December 2004.

As of December 31, 2004, PGE has power purchase contracts with other counterparties, requiring payments of approximately $532 million in 2005, $227 million in 2006, $94 million in 2007, $95 million in both 2008 and 2009, and $832 million over the remaining years of the contracts, which expire at varying dates from 2005 to 2035. As of December 31, 2004, PGE has power sale contracts with other counterparties of approximately $145 million in 2005, $44 million in 2006, $5 million in 2007, 2008, and 2009, and $15 million over the remaining years of the contracts, which expire at varying dates from 2005 to 2012. PGE also has power capacity contracts as of December 31, 2004 that require payments of approximately $24 million annually through 2009 and are expected to average approximately $20 million from 2010 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. Under this contract, PGE was owed 1,116 MWhs of electricity at December 31, 2004, all of which was received by the end of February 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, 2004, PGE owed 8,691 MWhs of electricity, all of which was delivered by the end of February 2005.

Leases

PGE has operating leases for its headquarters complex and for a coal-handling facility at Boardman. Lease payments charged to expense were $10 million in both 2004 and 2003 and $9 million in 2002.

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

Year Ending December 31	**Operating Leases (Net of Sublease Rentals)**
2005	$ 10
2006	8
2007	8
2008	8
2009	8
Remainder	190
Total	$232

Included in the above table is approximately $131 million for PGE's headquarters complex reflecting the base lease period through 2018 and renewal period options through 2043. The initial 25-year lease of the Boardman coal-handling facility expires in 2005. Under the lease agreement, PGE has the option to purchase the facility or to renew the lease for one or more renewal terms not to exceed an aggregate of twenty additional years. PGE has exercised its option to extend the lease to 2010.

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 Uti lity 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 2005 is approximately $221 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 endeavor to minimize net power costs for its retail customers, and in its trading activities to participate in electricity and natural gas markets. 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.

For retail (non-trading) activities, changes in fair value of derivative instruments prior to settlement are recorded net in Purchased Power and Fuel expense. As these derivative instruments are settled, sales are recorded in Operating Revenues, with purchases, natural gas swaps and futures recorded in Purchased Power and Fuel expense. In accordance with EITF 03-11, which became effective on October 1, 2003, PGE began recording the non-physical settlement of non-trading electricity derivative activities on a net basis in Purchased Power and Fuel expense, resulting in reductions to both Operating Revenues and Purchased Power and Fuel expense of $296 million and $90 million in 2004 and 2003, respectively. The physical settlement of sales and purchases involving non-trading electricity derivative activities are recorded in Operating Revenues and Purchased Power and Fuel expense, respectively.

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 therefore are deferred pursuant to SFAS No. 71.

For energy trading activities, EITF 02-3 requires that all unrealized and realized gains and losses associated with "energy trading activities" be reported on a net basis. Accordingly, PGE records unrealized and realized gains and losses from trading activities on a net basis as a component of Operating Revenues.

Non-Trading Activities

As PGE's primary business is to serve its retail customers, it uses derivative instruments, including electricity forward and option, and natural gas forward, swap, option, and futures contracts to manage its exposure to commodity price risk and to minimize net power costs for customers. Most of PGE's non-trading wholesale sales have been to utilities and power marketers and have been predominantly short-term. 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. 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 28, 2004 that will settle during the 12-month period from January 1, 2005 to December 31, 2005. Such valuation was based on forward price curves in effect on November 11, 2004 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 in effect for 2005, unrealized gains and losses on new 2005 derivatives not included in rates, and changes in fair value of derivatives used to set rates, are not deferred as regulatory assets or regulatory liabilities.

In 2004, PGE recorded $6 million in net unrealized gains in earnings in its retail portfolio; this was offset by recording a $22 million SFAS No. 71 regulatory liability. In 2003, PGE recorded $29 million in net unrealized gains in earnings in its retail portfolio; this was partially offset by recording a $16 million SFAS No. 71 regulatory liability. In 2002, PGE recorded $15 million in net unrealized gains in earnings in its retail portfolio; this was offset by recording a $16 million SFAS No. 71 regulatory liability.

Derivative activities recorded in OCI for 2004 from cash flow hedges consist of $20 million of unrealized gains from new contracts and changes in fair value and $10 million in net gains reclassified into earnings for contracts that settled during the period. A $16 million SFAS No. 71 regulatory liability was recorded in 2004.

Derivative activities recorded in OCI for 2003 from cash flow hedges consist of $14 million of unrealized gains from new contracts and changes in fair value. Also recorded in OCI in 2003 were $4 million in net gains reclassified into earnings for contracts that settled during the period, and $15 million in net gains for the discontinuance of cash flow hedges due to the probability that the original forecasted transaction will not occur. A $4 million SFAS No. 71 regulatory asset was recorded in 2003.

Derivative activities in OCI for 2002 from cash flow hedges consist of $11 million of net unrealized gains in new contracts and changes in fair value, $1 million in net losses reclassified into earnings for contracts that settled during the period, and $1 million in net gains for the discontinuance of cash flow hedges due to the probability that the original forecasted transactions will not occur. In 2002, $8 million of the $11 million of net unrealized gains were offset by the recording of a SFAS No. 71 regulatory liability.

Hedge ineffectiveness from cash flow hedges was not material in 2004, 2003, and 2002. As of December 31, 2004, the maximum length of time over which PGE is hedging its exposure to such transactions is approximately 36 months. The Company estimates that of the $14 million of net unrealized gains at December 31, 2004, $11 million will be reclassified into earnings within the next twelve months, and $3 million will be reclassified over the remaining twenty-four months.

Trading Activities

PGE utilizes electricity forward, swap, and option contracts, natural gas forward, swap, option, and futures contracts to participate in electricity and natural gas markets. Such activities are 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. In early 2005, PGE discontinued its trading activities; existing trading transactions will continue to settle through December 31, 2005.

The following tables indicate unrealized and realized gains and losses on electricity and fuel trading activities and transaction volumes for electricity trading contracts that settled for the year ended:

	Trading Activities				
	(In Millions)				
	2004		2003		2002

Unrealized Gain (Loss)	$ 1		$ 1		$(4)
Realized Gain	-		1		3
Net Gain (Loss) in Operating Revenues	$ 1		$ 2		$(1)

	Electricity Trading				
	Megawatt Hours (thousands)				
	2004		2003		2002
Sales	9,699		13,551		11,292
Purchases	9,699		13,551		11,292

The fair values as of December 31 related to price risk management trading activities are set forth below (in millions):

	Fair Values				**Fair Values**		
	December 31, 2004				**December 31, 2003**		
	Assets		**Liabilities**		**Assets**		**Liabilities**
Electric forward contracts	$4		$4		$22		$22
Natural gas swaps	2		1		2		2
Total	$6		$5		$24		$24
Note: All contracts have a maturity of one year or less.							

Note 9 - Jointly Owned Plant

At December 31, 2004, PGE had the following investments in jointly owned generating plants (dollars in millions):

Facility	**Location**	**Fuel**	**MW Capacity**	**PGE % Interest**	**Plant In Service**	**Accumulated Depreciation (*)**
Boardman	Boardman, OR	Coal	380	65.00	$404	$244
Colstrip 3 and 4	Colstrip, MT	Coal	296	20.00	469	278
Pelton/Round Butte	Madras, OR	Hydro	298	66.67	77	33

(*) 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 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, 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 su spend 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 re lated 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, beginning in October 2000. 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 decommissioning costs of Trojan is unaffected by the settlement agreements or the OPUC orders.

The URP filed a complaint challenging the settlement agreements and the OPUC'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, 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). 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 Partia l 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 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, 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 orders remanding this matter to the OPUC.

On August 31, 2004, the administrative law judge issued an 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 August 31, 2004 Order. On December 2, 2004, a pre-hearing conference was held and a briefing schedule was established, with hearings scheduled to begin in August 2005. On December 20, 2004, the URP and Class Action Plaintiffs filed an application with the OPUC for reconsideration of the OPUC's October 18, 2004 Order. On February 11, 2005, the OPUC denied reconsideration.

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 Rules of Civil Procedure, Potential Plaintiffs may not bring the suit until 30 days after the date of the Notice.

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 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 (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 enric hment, conversion, statutory violations, and seeking punitive damages. On February 24, 2005, PGE requested a declaratory ruling from the OPUC on this matter. Management cannot predict the ultimate outcome of this matter.

Union Grievances - Grievances have been filed by several members of the International Brotherhood of Electrical Workers (IBEW) Local 125, 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 Oregon 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. 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 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. 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.

The EPA is coordinating activities of natural resource agencies and the DEQ and in early 2002 requested and received signed "administrative orders of consent" from several Potentially Responsible Parties, voluntarily committing themselves to further remedial investigations; PGE was not requested to sign, nor has it signed, such an order.

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 or estimate any potential loss. However, it believes this matter will not have a material adverse impact on its 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. Sufficient information is currently not available to determine the total costs related to this matter. However, PGE believes this matter will not have a material adverse impact on its financial statements.

Note 11 - Asset Retirement Obligations

SFAS No. 143, 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.

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.

Cumulative Effect - In 2003, PGE recorded a $2 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.

The $11 million transition adjustment for rate-regulated utility plant, consisting of the Boardman and Colstrip Units 3 and 4 coal plants, Beaver and Coyote Springs gas turbine plants, and the Bull Run hydro project, was deferred as a regulatory liability pursuant to SFAS No. 71.

The ARO associated with decommissioning of the Trojan plant was recorded on a nominal dollar basis at the time of its abandonment in 1993, with costs to be recovered through regulation recorded as a regulatory asset. With 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.

Asset Retirement Obligations Activity - Upon adoption of SFAS No. 143, PGE recorded AROs of $15 million for utility plant and $1 million for other property and adjusted the ARO for the Trojan Plant to $121 million.

The following presents the 2004 and 2003 effects and 2002 proforma effects to the balances and activities in AROs had SFAS No. 143 been in effect for all periods:

					Proforma	
	Year Ended		Year Ended		Year Ended	
	December 31, 2004		December 31, 2003		December 31, 2002	
Beginning Balance	$	121	$	137	$	145
Activity						
AROs incurred		-		-		-
Expenditures		(17)		(21)		(18)
Accretion		6		6		6
Revisions		2		(1)		4
Ending Balance	$	112	$	121	$	137

-

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 Transition Costs - PGE is a 67.5% owner of Trojan. In early 1993, PGE ceased commercial operation of the nuclear plant. Since plant closure, PGE has committed itself to a safe and economical transition toward a decommissioned plant. A license amendment for the Independent Spent Fuel Storage Installation (ISFSI), an interim dry storage facility that will house the nuclear fuel on the plant site until permanent storage is available, was approved by the NRC in 2002, with fuel loading completed in 2003. The fuel is contained in thirty-four multi-purpose canisters, which have been loaded, sealed, and placed on the ISFSI pad. With the completion of the transfer of spent nuclear fuel to an on-site storage facility, transition activities associated with operating, maintaining, and securing the spent fuel pool have ceased.

Decommissioning - The Trojan decommissioning plan includes an estimate of PGE's cost to decommission the plant. In March 2004, PGE updated the decommissioning plan cost estimate to reflect revised inflation rates, in compliance with NRC procedures. At December 31, 2004, the asset retirement obligation, measured at estimated fair value in accordance with SFAS No. 143, is $96 million. (see Note 11, Asset Retirement Obligations).

ASSET RETIREMENT OBLIGATION (ARO)

(In Millions)

Balance, 12/31/03	$	104
2004 Expenditures		(16)
2004 Accretion		6
2004 Estimate Revisions		2
Balance, 12/31/04	$	96
Total expenditures through 12/31/04	$	206

The original cost estimate for the Trojan decommissioning plan was based on a site-specific study performed by an engineering firm experienced in estimating the cost of decommissioning nuclear plants. Subsequent updates have been prepared by PGE. Final site restoration activities are anticipated to begin in 2018 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). Remaining decommissioning activities consist of demolition of the existing structures, operation of the ISFSI to the year 2018, and decommissioning of the ISFSI.

DECOMMISSIONING TRUST ACTIVITY

(In Millions)

		2004		2003
Beginning Balance	$	35	$	31
Activity				
Contributions		14		26
Earnings		1		-
Disbursements		(28)		(22)
Ending Balance	$	22	$	35

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 an external trust fund, which is limited to reimbursing PGE for activities covered in Trojan's decommissioning plan. Funds were withdrawn during 2004 to cover the costs of general decommissioning and to fund the operation of the ISFSI. A $12 million trust fund contribution made in 2003, related to NRC funding assurance requirements, was refunded to the Company in 2004 upon completion of radiological decommissioning. 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 contracted with the USDOE for permanent disposal of its 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, allowing final decommissioning and release of the Trojan 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 President Bush signed the Yucca Mountain resolution into law in July 2002. Lawsuits have been filed objecting to the recommendation of Yucca Mountain as a nuclear waste repository. The USDOE, which must apply to the NRC for an operating license, did not submit an application before the December 1, 2004 deadline. Further delays may make it difficult for PGE to move its high-level radioactive waste, currently contained in the ISFSI, to permanent underground storage by 2018.

On January 6, 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 have paid the required assessment of $109 million and 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 and which will terminate in 2006. PGE is current on all payments.

New 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 ISFSI's. 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 require ments 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. In addition, the NRC has reduced the required primary nuclear insurance coverage for Trojan to $100 million. The NRC has allowed PGE to self-insure for on-site decontamination related to spent nuclear fuel stored on-site in the ISFSI. PGE continues to carry non-contamination property insurance on the Trojan plant in the amount of $25 million.

Trojan ISFSI Pollution Control Tax Credits - In late 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 the ISFSI. The OEQC rules require that the tax credits are to be spread over a ten-year period, beginning in 2004. In addition, PGE recorded a $2 million regulatory liability to defer the utilization of these tax credits in 2004 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, 2004	December 31, 2003
Receivables from affiliated companies		
Enron Corp and other Enron Subsidiaries in Bankruptcy:		
Merger Receivable	$ -	$ 73
Allowance for Uncollectible - Merger Receivable	-	(73)
Accounts Receivable[a]	-	3
Other Allowance for Uncollectible Accounts[a]	-	(3)
Other Enron Subsidiaries:		
Portland General Holdings, Inc. - in Bankruptcy		
Accounts Receivable[a]	5	5
Other Allowance for Uncollectible Accounts [a]	(1)	(2)
PGH II and its subsidiaries - not in Bankruptcy		
Accounts Receivable[a]	1	2
Other Allowance for Uncollectible Accounts[a]	(1)	-
Note Receivable[a]	-	1

Payables to affiliated companies		
Enron Corp:		
Accounts Payable[b]	4	6
Income Taxes Payable[c]	21	36

(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	2004	2003	2002
Revenues from affiliated companies			
Other Enron subsidiaries:			
Sales of electricity and transmission[a]	$ -	$ -	$ 1
Expenses billed to affiliated companies			
Portland General Holdings, Inc. - in Bankruptcy:			
Intercompany services[b]	-	-	1
PGH II and its subsidiaries - not in Bankruptcy:			
Intercompany services[b]	1	1	1
Expenses billed from affiliated companies			
Enron Corp:			
Intercompany services[b]	28	34	32
Interest, net from affiliated companies			
Enron Corp:			
Interest income (expense)[c]	-	(8)	7
PGH II and its subsidiaries:			
Interest income[c]	-	-	3

(a) Included in Operating Revenues on the Consolidated Statements of Income

(b) Included in Administrative and other on the Consolidated Statements of Income

(c) Included in Other Income (Deductions) on the Consolidated Statements of Income

Distributions to Enron - On October 15, 2002, PGE submitted proofs of claim to the Bankruptcy Court for amounts representing intercompany obligations between PGE and Enron and its bankrupt subsidiaries arising prior to the commencement of the bankruptcy case. In December 2004, PGE made a distribution of all pre-petition amounts owed by Enron and its affiliates, and related proofs of claim, except for those related to Portland General Holdings, Inc. The distribution was made in an effort to eliminate these pre-petition intercompany balances from PGE's books in order to remove the uncertainties regarding the value of the proofs of claim. The specific types of claims distributed (and their related amounts) are discussed below.

Merger Receivable - In 1997, Enron acquired PGE through a merger between Enron and PGC, the former parent corporation of PGE. Under terms of the 1997 merger agreement, Enron and PGE agreed to provide $105 million of benefits to PGE's customers through price reductions payable over an eight-year period. Although the remaining liability to customers was reduced to zero under terms of a 2000 settlement agreement related to PGE's recovery of its investment in Trojan, Enron remained obligated to PGE for the approximate $80 million remaining balance and continued to make monthly payments, as provided under the merger agreement.

Enron suspended its monthly payments to PGE in September 2001, pursuant to its Stock Purchase Agreement with NW Natural, under which NW Natural was to have assumed Enron's merger payment obligation upon its purchase of PGE. The Stock Purchase Agreement was terminated in May 2002. At the time of Enron's bankruptcy filing on December 2, 2001, Enron owed PGE approximately $73 million (including accrued interest) for the Merger Receivable. Due to the uncertainty of the realization of the Merger Receivable, PGE established a reserve for the full amount of this receivable in December 2001. PGE accrued interest on the Merger Receivable and recorded an offsetting reserve from the December 2001 Enron bankruptcy filing until December 2003. Both the interest and the related reserve accrued in Enron's post-petition bankruptcy period were reversed in December 2003 to reflect PGE's proofs of claim filing. In December 2004, in conjunction with the distribution of pre-petition amounts to Enron (as discussed above), PGE reversed the $73 million Merger Receivable and related reserve. For further information, see Note 15, Enron Bankruptcy.

Income Taxes Receivable and Payable - As a member of Enron's consolidated income tax return, PGE made income tax payments to Enron for PGE's income tax liabilities. PGE and its subsidiaries ceased to be a member of Enron's consolidated tax group on May 7, 2001. On December 24, 2002, PGE and its subsidiaries again became a member of Enron's consolidated tax group. The $21 million income taxes payable to Enron at December 31, 2004 represents a net current income taxes payable for the fourth quarter of 2004 that were paid to Enron in January 2005. During 2004, PGE paid $83 million to Enron for income taxes payable, of which $21 million was for the period from December 24, 2002 to December 31, 2003. Income tax payments for those periods were withheld until PGE's December 24, 2002 reconsolidation with Enron was agreed to by the IRS on February 2, 2004. The remaining $62 million tax payment to Enron represented $55 million for the f irst nine months of 2004 and $7 million net taxes payable (net of receivables) for the period up to May 7, 2001 (pre-petition) which was part of the December 2004 distribution of pre-petition amounts discussed above. The $36 million income taxes payable to Enron at December 31, 2003 represented $29 million related to income taxes owed for the period December 24, 2002 through December 31, 2003 and $7 million for income taxes owed up to May 7, 2001 (pre-petition liability included as an offset in PGE's proofs of claim filing). For further information, see Note 15, Enron Bankruptcy.

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 employee benefits and certain insurance coverage. Transactions with affiliates are subject either to approval of, or confirmation filing requirements with, the OPUC and, as long as PGE is a subsidiary of a registered holding company under PUHCA, the SEC. 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. Under SEC regulations, both services provided to, and received from, affiliates are charged at cost. Services will be provided at cost unless there is a conflict between OPUC and SEC regulations, in which case PGE and Enron have agreed n ot to provide the services until the matter can be resolved.

<u>Enron</u> - In 2004, Enron passed through to PGE approximately $25 million for medical/dental benefits and retirement savings plan matching and $3 million for insurance coverage. Beginning in 2004, Enron no longer bills PGE for corporate overhead costs. In 2003, Enron passed through to PGE approximately $20 million for medical/dental benefits and retirement savings plan matching, $1 million for insurance coverage, and billed $13 million for corporate overhead costs. In 2002, Enron passed through to PGE approximately $19 million for retirement savings plan matching and medical/dental benefits and billed $13 million for corporate overhead costs. Effective 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 bills PGE for these services.

Intercompany payables to Enron were paid by PGE until Enron filed for bankruptcy in early December 2001, except for payments for employee benefit plans. In reaching an agreement with Enron regarding the allocation of corporate overheads in the post-bankruptcy period, PGE resumed payments for corporate overhead costs from March 2003 through December 2003. During 2004, PGE paid $30 million to Enron, consisting of $23 million for employee benefits, $3 million for insurance premiums, and $4 million for pre-petition period corporate overheads and restricted stock costs. The payment of the pre-petition period amounts was part of PGE's December 2004 distribution of pre-petition amounts to Enron. At December 31, 2004, PGE had $4 million payable to Enron for employee benefits. During 2003, PGE paid $47 million to Enron, consisting of $27 million for corporate overhead costs and $20 million for employee benefits. The $6 million payable to Enron at December 31, 2003 consisted of $4 million for corporate overheads and $2 million for employee benefits.

In December 2004, in conjunction with the distribution of pre-petition amounts discussed above, PGE reversed the $1 million account receivable from Enron and the related reserve for pre-petition employee benefits. At December 31, 2004, PGE has no remaining pre-petition intercompany balances with Enron.

<u>Other Enron Subsidiaries in Bankruptcy</u> - PGE purchased electricity from, and sold electricity to, Enron Power Marketing, Inc. (EPMI) during 2001. PGE also provided transmission services to EPMI under a transmission contract that was guaranteed by Enron. PGE has not purchased electricity from, or sold electricity to, EPMI since December 2001, and EPMI has not paid for transmission services since September 2002.

PGE was owed a net $2 million by EPMI for power sales and transmission services of $1 million in 2001 and 2002. EPMI is part of Enron's bankruptcy proceedings. Due to uncertainties associated with the realization of this receivable from EPMI, a $2 million reserve was established. PGE included amounts owed by EPMI for power sales and transmission services in the proofs of claim filed with the Bankruptcy Court.

In April 2003, PGE entered into a settlement agreement with EPMI and Enron to terminate the transmission contract. The settlement agreement was approved by the Bankruptcy Court and accepted by the FERC. Under the settlement, PGE retained a $200,000 deposit from EPMI related to the transmission contract and Enron's guaranty was terminated. PGE amended its proofs of claim in the Enron bankruptcy to include a pre-petition unsecured claim against EPMI and a pre-petition guaranty claim against Enron for $1 million owed PGE for transmission services. In December 2004, as part of the distribution of pre-petition amounts discussed above, PGE reversed the $2 million account receivable from EPMI and the related reserve. As of December 31, 2004, PGE has no remaining account receivable or payable balances with EPMI. For further information, see Note 15, Enron Bankruptcy.

<u>Portland General Holdings, Inc. - in Bankruptcy</u> - 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 has been procedurally consolidated with the Enron bankruptcy proceeding. No PGH subsidiaries are included in the bankruptcy filing. At December 31, 2004 and 2003, 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 other corporate governance services provided by PGE to PGH in 2002. During 2003, PGE submitted proofs of claim to the Bankruptcy Court for approximately $5 million for employee benefit and corporate governance services. Based on management's assessment of the realizability of the receivable from PGH, a reserve of $2 million was established in December 2002. In June 2004, PGE reduced the reserve by $1 million based on management's c urrent assessment. PGE will continue to assess the collectibility of this receivable.

In 1999, PGE transferred $21 million of corporate owned life insurance policies to PGH, creating a receivable balance owed by PGH to PGE. PGH transferred these policies to a trust to pay certain non-qualified benefit plan obligations owed by PGH, leaving with PGH the receivable balance due PGE. Later in 1999, PGH recorded a capital transaction with its wholly owned subsidiary PGH II, Inc. (PGH II), reflecting an assumption by PGH II of the obligation to pay the $21 million owed to PGE. PGH retained the residual interest in the trust owned life insurance policies. The transfer to PGH II was the result of negotiations between Enron and Sierra Pacific Resources related to the proposed sale of PGE and PGH II to Sierra (the sale of which was later terminated in April 2001). In the proposed sale of PGE and PGH II to NW Natural, the obligation to pay the intercompany payable to PGE would have been assumed by NW Natural. In June 2002, due to the termination of the sale agreement with NW N atural, the PGE intercompany payable was transferred back to PGH. Due to the effects of both the termination of the sale agreement with NW Natural and the complexities of the Enron bankruptcy on the period of time required to collect this receivable balance from PGH, PGE's board of directors on July 25, 2002 approved the transfer of the intercompany receivable at PGE to Enron in the form of a non-cash dividend. In July 2002, the balance due PGE from PGH of $27 million, including accrued interest, was transferred to Enron as a non-cash dividend.

PGH II and its Subsidiaries - not in Bankruptcy - PGH II, a wholly owned subsidiary of PGH, is the parent company of various subsidiaries that receive services from PGE. PGH II and its subsidiaries are not part of Enron's or PGH's bankruptcy proceedings. PGH II subsidiaries include Portland General Distribution, LLC (PGDC), a telecommunications company, Microclimates, Inc., a project management company, and Portland Energy Solutions Company, LLC (PES), which provided cooling services to buildings in downtown Portland, Oregon.

During 2004, 2003 and 2002, PGE billed PGH II and its subsidiaries $1 million annually, for employee and other corporate governance services. As of December 31, 2004, PGE had outstanding accounts receivable from PGDC of $1 million for employee and other corporate governance services, offset by an approximate $0.9 million uncollectible reserve. At December 31, 2003, PGE had outstanding accounts and notes receivable from PGH II and its subsidiaries of $3 million, comprised of $2 million for employee and other corporate governance services ($1 million each owed by PGDC and PES) and a $1 million secured loan to PES.

PGE and PES had entered into a revolving credit agreement under which PGE had agreed to advance funds to PES to complete a district cooling system project. Advances accrued interest at 16% per annum. Interest paid by PES to PGE in excess of PGE's authorized cost of capital (9.083%) was deferred for future refund to PGE's customers. In April 2004, PES sold substantially all of its assets to an unrelated third party. The proceeds from the sale were used to repay all amounts PES owed to PGE, including trade payables and amounts due under the loan.

In September 2004, PGDC sold substantially all of its assets to an unrelated third party. The proceeds from the sale are expected to repay the unreserved amounts that PGDC owes to PGE.

On November 8, 2004, PGH II sold all of the common stock of Microclimates, Inc. to an unrelated third party. Prior to the sale, PGE received payment for all amounts owed by Microclimates

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 headquarter complex. Intercompany balances and transactions have been eliminated in consolidation.

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

Interest Income and Expense - Interest on the Enron Merger Receivable balance and the related reserve accrued in Enron's post-petition bankruptcy period were reversed in December 2003, as previously discussed. Accounts receivable balances from PGH II and its subsidiaries accrue interest at 9.5%. Receivable balances from PGH also accrued interest at 9.5% until PGH filed bankruptcy and the interest accrual was discontinued. Prior to 2001, interest was accrued at 9.5% on other outstanding receivable and payable balances with Enron and its other subsidiaries.

Note 14 - Receivables and Refunds on Wholesale Market Transactions

Receivables - California Wholesale Market

As of December 31, 2004, 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 federally-mandated 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 has now begun to hear the numerous appeals. It has bifurcated appeals of the existing cases before it into two phases. The first will consider argument s regarding jurisdictional issues and the permissable 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 has commenced on this first phase. 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. Under the new allocation methodology, 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.

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. In December 2004, the FERC requested comments regarding the manner in which such studies should be conducted and the principles that should control. PGE and numerous other parties filed comments and reply comments in January 2005. A decision by the FERC to adopt PGE's approach to these studies could reduce the Company's ultimate refund liability.

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). Interest has not yet been recorded by the Company. 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.

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. PGE 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.

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 - Enron Bankruptcy

Commencing 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 is not included in the bankruptcy, but the common stock of PGE held by Enron is part of the bankruptcy estate.

Enron and its debtor-in-possession subsidiaries (collectively the Debtors) filed their Chapter 11 plan (the Chapter 11 Plan) and related disclosure statement (the Disclosure Statement) with the Bankruptcy Court. The Chapter 11 Plan and Disclosure Statement, as amended, provide information about the assets that are in the bankruptcy estate, including the common stock of PGE, and how those assets will be distributed to the creditors. The Chapter 11 Plan was confirmed by the Bankruptcy Court on July 15, 2004 and it became effective on November 17, 2004.

On March 10, 2005, the OPUC issued Order No. 05-114, in which it denied Oregon Electric's application to purchase PGE. Enron and Oregon Electric have stated that they are reviewing the Order and evaluating their next steps. Under the Chapter 11 Plan, if PGE is not sold to Oregon Electric or another buyer, the shares of PGE's common stock will be distributed over time to the Debtors' creditors. It is anticipated that once a sufficient amount of the common stock is distributed to creditors, the shares would be publicly traded.

Management cannot predict with certainty what impact the Chapter 11 Plan may have on PGE. However, since the Chapter 11 Plan has become effective, the assets and liabilities of PGE will not become part of the Enron estate in bankruptcy.

Notwithstanding the above, PGE may have potential exposure to certain liabilities and asset impairments as a result of Enron's bankruptcy. These are:

1. **Amounts Due from Enron and Enron-Supported Affiliates in Bankruptcy** - As described in Note 13, Related Party Transactions, in December 2004, PGE made a distribution of all pre-petition amounts owed by Enron and its affiliates, and related proofs of claim, except for those related to Portland General Holdings, Inc. The distribution was made in an effort to eliminate all pre-petition intercompany balances from PGE's books in order to remove the uncertainties regarding the value of the proofs of claim. Following the distribution, PGE's balance sheet at December 31, 2004 was cleared

of all pre-petition intercompany balances with Enron and its affiliates, with the exception of PGH. As of December 31, 2004, PGE has outstanding accounts receivable of $5 million due from PGH which is part of the Enron bankruptcy proceedings. Based on management's assessment of the realizability of accounts receivable from PGH, a reserve of $1 million has been established.

2. **Controlled Group Liability** - Enron's bankruptcy has raised questions regarding potential PGE liability for certain employee benefit plan and tax obligations of Enron.

Pension Plans

Funding Status

The pension plan for the employees of PGE (the PGE Plan) is separate from the Enron Corp. Cash Balance Plan (the Enron Plan). At December 31, 2004, the total fair value of PGE Plan assets was $2 million higher than the projected benefit obligation on a SFAS No. 87 (Employers' Accounting for Pensions) basis. In addition, the PGE Plan was over-funded on an accumulated benefit obligation basis by about $58 million as of December 31, 2004.

Enron's management has informed PGE that, as of December 31, 2004, the assets of the Enron Plan were less than the present value of all accrued benefits by approximately $48 million on a SFAS No. 87 basis and approximately $166 million on a plan termination basis. The Pension Benefit Guaranty Corporation (PBGC) insures pension plans, including the PGE Plan and the Enron Plan and the pension plans of other Debtors. Enron's management has informed PGE that the PBGC has filed claims in the Enron bankruptcy cases with respect to the Enron Plan and the plans of the other Debtors (Pension Plans). The claims are duplicative in nature because certain liability under ERISA is joint and several. Five of the PBGC's claims represent unliquidated claims for PBGC insurance premiums (the Premium Claims), five are unliquidated claims for due but unpaid minimum funding contributions (the Contribution Claims) under the Internal Revenue Code of 1986, as amended, and ERISA, 26 U.S.C. Section 412, an d 29 U.S.C. Section 1082, and the remaining five claims are for unfunded benefit liabilities (the UBL Claims). PBGC has informed the Debtors that it has reduced its aggregate estimate of the UBL Claims for the Pension Plans to $321.8 million, including $240.2 million for the Enron Plan and $64.6 million related to the PGE Plan, although it has not amended the UBL Claims to reflect those amounts. Except for one PBGC premium which is not material, the Debtors are current on their PBGC premiums and their minimum funding contributions to the Pension Plans. Therefore, the Debtors' value the Premium Claims and the Contribution Claims at $0. Enron management has informed PGE that the PBGC has informally alleged in pleadings filed with the Bankruptcy Court that the UBL claim related to the Enron Plan could increase by as much as 100%. PBGC has not provided support (statutory or otherwise) for this assertion and Enron management disputes the validity of any such claim.

Because the Enron Plan is underfunded, in certain circumstances the Enron Plan may be terminated and taken control of by the PBGC upon approval of a Federal District Court. In addition, with consent of the PBGC, Enron could seek to terminate the Enron Plan while it is underfunded. Moreover, if it satisfies certain statutory requirements, Enron can commence a voluntary termination by fully funding the Enron Plan, in accordance with the Enron Plan terms, and terminating it in a "standard" termination in accordance with the Employee Retirement Income Security Act of 1974, as amended (ERISA).

Upon termination of an underfunded pension plan, all of the members of the ERISA controlled group of the plan sponsor become jointly and severally liable for the plan's underfunding. The PBGC can demand payment from one or more of the members of the controlled group. If payment is not made, a lien in favor of the PBGC automatically arises against all of the assets of that member of the controlled group. The amount of the lien is equal to the lesser of the underfunding or 30% of the aggregate net worth of all of the controlled group members. In addition, if the sponsor of a pension plan does not timely satisfy its minimum funding obligation to the pension plan, once the aggregate missed amounts exceed $1 million, a lien in favor of the plan in the amount of the missed funding automatically arises against the assets of every member of the controlled group. In either case, the PBGC may file to perfect the lien and attempt to enforce it against the assets of the plan sponsor and the members of its controlled group. PGE management believes that the lien would be subordinate to prior perfected liens on the assets of the members of the controlled group. Substantially all of PGE's assets are subject to a prior perfected lien in favor of the holders of its First Mortgage Bonds. PGE management believes that any lien asserted by the PBGC would be subordinate to that lien. In addition, the PBGC retains an interest in any sales proceeds generated by the Enron auction process for PGE. Based on discussions with Enron's management, PGE's management understands that Enron has made all required contributions to date.

On January 30, 2004, the Bankruptcy Court entered the order authorizing Enron and certain of its affiliated Debtors to contribute $200 million to the Pension Plans and terminate them in a manner that should eliminate the PBGC's claims. However, there can be no assurance that Enron will have the ability to obtain funding for accrued benefits on acceptable terms, that certain funding contingencies will be met, or that the required government agencies that review pension plan terminations will approve the termination of the Pension Plans. If the proposal to fund and terminate the Enron Plan is approved and consummated, it should eliminate any need for the PBGC to attempt to collect from PGE any liability related to the Enron Plan.

On June 2, 2004, the PBGC issued notices to Enron and Enron Facility Services, Inc. (EFS), an Enron affiliate, stating that the PBGC had determined that the Pension Plans should be terminated. On June 3, 2004, the PBGC filed a complaint (PBGC Complaint) in the District Court for the Southern District of Texas against Enron seeking an order (i) terminating the Pension Plans; (ii) appointing the PBGC the statutory trustee of the Pension Plans; (iii) requiring transfer to the PBGC of all records, assets or other property of the Pension Plans required to determine the benefits payable to the Pension Plans' participants; and (iv) establishing June 3, 2004 as the termination date of the Pension Plans.

The PGE Plan was not included in the above Complaint, nor was PGE issued a similar notice of determination regarding the PGE Plan. The PBGC has taken no action to terminate the PGE Plan.

On August 4, 2004, Enron, EFS and certain Debtors filed a complaint with the Bankruptcy Court (Enron Complaint) seeking (i) a declaration that the PBGC Complaint is void; and (ii) orders staying, restraining and enjoining the PBGC from continuing the prosecution of the PBGC Complaint and preliminarily and permanently enjoining the PBGC to cease prosecution of, and to dismiss with prejudice, the PBGC Complaint. On September 8, 2004, the Bankruptcy Court denied the Enron Complaint.

Unless and until the District Court authorizes the PBGC to terminate the Pension Plans and the PBGC makes a demand on PGE to pay some or all of any unfunded benefit liabilities under the Pension Plans, which would not occur unless the Proposed Pension Settlement is not approved by both the District and Bankruptcy Courts or the parties do not satisfy the terms of the Proposed Pension Settlement. PGE has no liability for the unfunded benefit liabilities and no termination liens arise against any PGE property.

Proposed Settlement

Enron management has informed PGE management that Enron has reached a settlement in principle with the PBGC, the terms of which have not yet been disclosed (the "Proposed Pension Settlement"). However, the Proposed Pension Settlement has caused the PBGC and Enron to file stays of the litigation in the District Court on the involuntary termination of the Pension Plans and in the Bankruptcy Court on the PBGC claims against the Debtors with respect to the Pension Plans and Enron's objection to such PBGC claims. The Proposed Pension Settlement must be filed and approved by the District Court and the Bankruptcy Court and all terms of the Proposed Pension Settlement must be satisfied for the contingent liability against PGE by the PBGC to be relinquished. If the Proposed Pension Settlement is not approved by both the District and Bankruptcy Courts or the parties do not satisfy all the terms of the Proposed Pension Settlement, and if the relief sought in the Enron Complaint is not obtained wh en the stay is lifted, Enron may be precluded from funding and terminating the Pension Plans as previously authorized by the Bankruptcy Court until, if at all, after resolution of the PBGC Complaint as the stay with respect to such litigation also would be lifted. In addition, in that case it may be possible, subject to applicable law, for the Enron Plan and PGE Plan to be merged while Enron and PGE are in the same controlled group, and any excess assets in the PGE Plan would reduce the deficiency in the Enron Plan. However, if the plans are not merged, the deficiency in the Enron Plan could become the responsibility of the PBGC and the PGE Plan assets would be undiminished.

If the Proposed Pension Settlement is approved, Enron would proceed with the standard termination of the Pension Plans as discussed above and any need for the PBGC to attempt to collect from PGE any liability related to the Enron Plan would be eliminated.

PGE management cannot predict the outcome of the above matters or estimate any potential loss. In addition, if the PBGC did look solely to PGE to pay any amount with respect to the Enron Plan, PGE would exercise all legal rights, if any, available to it to defend against such a demand and to recover any contributions from the other solvent members of the controlled group. No reserves have been established by PGE for any amounts related to this issue.

Retiree Health Benefits

PGE management understands, based on discussions with Enron management, that Enron maintains a group health plan for certain of its retirees. If retirees of Enron lose coverage under Enron's group health plan for retirees due to Enron's bankruptcy proceedings, the retirees must be provided the opportunity to purchase continuing coverage (known as COBRA Coverage) from an Enron group health plan, if any, or the appropriate group health plan of another member of the controlled group. The liability for benefits under the Enron group health plan for retirees (other than potential liability to provide COBRA Coverage) is not a joint and several obligation of other members of the Enron controlled group, including PGE, so PGE would not be required to assume from Enron, or otherwise pay, any liabilities from the Enron group health plan. Neither PGE nor any other member of Enron's controlled group would be required to create new plans to provide COBRA Coverage for Enron's retirees, and the retirees w ould not be entitled to choose the plan from which to obtain coverage. Retirees electing to purchase COBRA Coverage would be provided the same coverage that is provided to similarly situated retirees under the most appropriate plan in the Enron controlled group. Retirees electing to purchase COBRA Coverage would be required to pay for the COBRA Coverage, up to an amount not to exceed 102% of the cost of coverage for similarly situated beneficiaries. Retirees are not required to acquire COBRA Coverage. Retirees will be able to shop for coverage from third party sources and determine which is the least expensive coverage.

PGE management believes that in the event Enron terminates retiree coverage, any material liability to PGE associated with Enron retiree health benefits is unlikely for two reasons. First, based on discussions with Enron management, PGE management understands that most of the retirees that would be affected by termination of the Enron plan are from solvent members of the controlled group and few, if any, live in Oregon. PGE management believes that it is unlikely that any PGE plans would be found to be the most appropriate to provide COBRA Coverage. Second, even if a PGE plan were selected, PGE management believes that retirees in good health should be able to find less expensive coverage from other providers, which will reduce the number of retirees electing COBRA Coverage. PGE management believes that the additional cost to PGE to provide COBRA Coverage to a limited number of retirees that are unable to acquire other coverage because they are difficult to insure or have preexi sting conditions will not have a material adverse effect on the financial statements. No reserves have been established by PGE for any amounts related to this issue.

Income Taxes

Under regulations issued by the U.S. Treasury Department, each member of a consolidated group during any part of a consolidated federal income tax return year is severally liable for the tax liability of the consolidated group for that year. PGE became a member of Enron's consolidated group on July 2, 1997, the date of Enron's merger with PGC. Based on discussions with Enron's management, PGE management understands that Enron has treated PGE as having ceased to be a member of Enron's consolidated group on May 7, 2001 and becoming a member of Enron's consolidated group once again on December 24, 2002. On December 31, 2002, PGE and Enron entered into a tax allocation agreement pursuant to which PGE agreed to make payments to Enron that approximate the income taxes for which PGE would be liable if it were not a member of Enron's consolidated group. Due to the uncertainty with the reconsolidation during 2003, PGE held certain tax payments due Enron. Enron obtained an ag reement from the IRS on February 2, 2004 stipulating that PGE did become a member of the Enron consolidated group on December 24, 2002. PGE resumed tax payments due Enron in early 2004.

Enron's management has provided the following information to PGE:

A. Enron's consolidated tax returns through 1995 have been audited and are closed.

B. The IRS has completed an audit of Enron's consolidated tax returns for 1996-2001. For years 1996 through 1999, Enron and its subsidiaries generated substantial net operating losses (NOLs). For 2000, Enron and its subsidiaries paid an alternative minimum tax. Enron's 2001 consolidated tax return showed a substantial net operating loss, which was carried back to the tax year 2000, for which Enron seeks a tax refund for taxes paid in 2000. The carryback of the 2001 loss to 2000 is expected to provide Enron and its subsidiaries with substantial NOLs which may be used to offset additional income tax liabilities that may result from future IRS audits for the taxable periods PGE was a member of Enron's consolidated federal income tax returns.

C. Enron's 2003 tax return was filed on September 14, 2004. As noted in paragraph B. above, Enron expects to have substantial NOLs from operations in years preceding 2003. Enron had 2003 NOLs sufficient to eliminate Enron's regular and alternative minimum income tax liabilities for 2003 and expects to have sufficient NOLs to offset its regular income tax liability for all subsequent periods through the date of consummation of its plan of reorganization.

On March 28, 2003, the IRS filed various proofs of claim for taxes in the Enron bankruptcy, including a claim for approximately $111 million with respect to income tax, interest, and penalties for taxable years in which PGE was included in Enron's consolidated tax return. The IRS has amended the proof of claim to reduce it to $20 million. The IRS and Enron reached a settlement on Enron's 1996-2001 tax liability on January 5, 2005. The settlement shows no net taxes due by Enron to the IRS. In the meantime, however, the settlement eliminates any further assessment of tax, interest or penalty for the years 1996-2001 against any member of the consolidated group in those years in excess of the overpayment currently held by the IRS.

However, with respect to periods after 2001, the Company would potentially remain severally liable for post-petition interest as well as any portion of the claim allowed in the bankruptcy that the IRS does not collect from the debtors.

To the extent, if any, that the IRS would look to PGE to pay any assessment not paid by Enron, PGE would exercise whatever legal rights, if any, that are available for recovery in Enron's bankruptcy proceedings, or to otherwise seek to obtain contributions from the other solvent members of the consolidated group. As a result, management believes the income tax, interest, and penalty exposure to PGE (related to any future liabilities from Enron's consolidated tax returns during the period PGE was a member of Enron's consolidated returns) would not have a material adverse effect on the financial statements. No reserves have been established by PGE for any amounts related to this issue.

Proposed Sale of PGE

On November 18, 2003, Enron and Oregon Electric, a newly-formed Oregon limited liability company financially backed primarily by investment funds managed by Texas Pacific Group, entered into a definitive agreement by which Enron will sell all of the issued and outstanding common stock of PGE to Oregon Electric. The transaction is valued at approximately $2.35 billion, including the assumption of debt. The final amount of consideration will be determined on the basis of PGE's financial performance between January 1, 2003 and closing. The transaction, previously approved by the Enron Board of Directors and supported by the Official Unsecured Creditors' Committee, was approved by the Bankruptcy Court on February 5, 2004. The transaction also requires approval of the OPUC, the SEC, the FERC, and certain other regulatory agencies. Applications for approval of the acquisition of PGE by Oregon Electric have been filed with the OPUC (on March 8, 2004), the FERC (on April 6, 2004), an d the SEC (on July 29, 2004). On January 3, 2005, the Oregon Energy Facility Siting Council issued a declaratory ruling that the proposed acquisition is not a transfer of ownership that would require a transfer of certain generating plant site certificates held by PGE. On February 14, 2005, the NRC approved the proposed acquisition.

In July 2004, the OPUC Staff and other intervenors filed their initial testimony that the sale of PGE to Oregon Electric not be approved unless greater net benefits for customers of PGE can be demonstrated. In September 2004, OPUC Staff recommended approval of the sale subject to certain conditions, including customer rate credits and limitations on distributions from PGE to Oregon Electric. Oregon Electric responded to concerns raised by the staff and other intervenors in subsequent rebuttal testimony and settlement meetings. Hearings and final oral arguments were held in late 2004. On March 10, 2005, the OPUC issued Order No. 05-114, in which it denied Oregon Electric's application to purchase PGE. Enron and Oregon Electric have stated that they are reviewing the Order and evaluating their next steps.

If PGE is not sold to Oregon Electric, under the Chapter 11 Plan, Enron will either sell the Company to another buyer or distribute the shares of PGE's common stock over time to the Debtors' creditors. Until shares are distributed to creditors, Enron will retain the right to sell PGE if it is determined that a sale would be in the best interest of the creditors. Until the sale to Oregon Electric is approved, another filing related to the sale of PGE is approved, or PGE's common stock is distributed to the Debtors' creditors, management cannot assess the impact on PGE's business and operations of a sale or the distribution of PGE's stock to the Debtors' creditors.

QUARTERLY COMPARISON FOR 2004 AND 2003 (Unaudited)

	March 31	June 30	September 30	December 31	Total
	(In Millions)				
2004					
Operating revenues (a)	$395	$332	$348	$379	$1,454
Net operating income	48	38	20	44	150
Net income before					
cumulative effect of a change					
in accounting principle	32	22	10	28	92
Net income	32	22	10	28	92
Income available for					
Common stock	32	22	10	28	92
2003					
Operating revenues (a)	$471	$410	$494	$377	$1,752
Net operating income	34	28	19	43	124
Net income (loss) before cumulative					
effect of a change in					
accounting principle	19	13	(4)	28	56
Net income (loss) (b)	21	13	(4)	28	58
Income (loss) available for					
Common stock	20	13	(4)	28	57

(a) Beginning in the fourth quarter of 2003, Operating revenues were reduced to 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'." The reduction in the fourth quarter of 2003 was $90 million. Reductions for 2004 were: $59 million (1st Qtr), $70 million (2nd Qtr), $101 million (3rd Qtr), and $66 million (4th Qtr). Amounts for periods prior to October 1, 2003 were not reclassified. For further information, see Note 1, Summary of Significant Accounting Policies, in the Notes to Financial Statements.

(b) In the third quarter of 2003, PGE recorded 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.

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 59 Director since February 1, 2004

Mr. Ballantine is 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 Scudder Funds, First Oak Brook Bancshares and the Oak Brook Bank, and American Healthways Corporation and Prisma Energy International Inc. (an Enron affiliate). He is also the Chairman of the financial services advisory group for Glencoe Capital, a private equity firm. Mr. Ballantine served as a director of Enron[2] from May 30, 2002 until November 17, 2004.

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

ROBERT S. BINGHAM, age 56 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 served as Associate Director of Restructuring for Enron[2] since February 2002 and Interim Chief Financial Officer and Interim Treasurer for Enron since November 2004. He served as Vice President and Chief Financial Officer of Pick Telecommunications Corp., a publicly-traded provider of long distance and prepaid calling card telecommunications services from August 1997 to February 1999. 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.

PEGGY Y. FOWLER, age 53 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 Boards of Regence Blue Cross/Blue Shield of Oregon, Oregon Independent College Foundation, Inc., George Fox University, Portland Streetcar Inc., PGE Foundation, and the Oregon Business Council.

Ms. Fowler also served as President of Portland General Holdings, Inc.[3] (an Enron affiliate) from March 1999 until June 2003.

Directors of the Registrant [1] - Continued

CORBIN A. MCNEILL, JR., age 65 Director since February 1, 2004

Mr. McNeill is Chair of the Board. 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 also serves on the Boards of NorthWestern Corporation, Ontario Power Generation, Associated Electric & Gas Services Limited, and the U.S. Naval Academy Alumni Association. Mr. McNeill served as a Director of Enron[2] from May 30, 2002 until November 17, 2004.

RAYMOND S. TROUBH, age 78 Director since April 1, 2004

Raymond S. Troubh has been a 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 WHX Corporation. Mr. Troubh served as a director of Enron[2] from November 27, 2001 until November 17, 2004 (including Chairman of the Board from November 14, 2002 until November 17, 2004).

ROBERT H. WALLS, JR., age 44 Director since July 2, 2002

Mr. Walls has served as Executive Vice President and General Counsel for Enron[2] since March 2002. He served as Deputy General Counsel from October 1999 until March 2002 and General Counsel for Enron International Inc.[4] (or one of its predecessor entities) from December 1993 to October 1999. Mr. Walls began his career with Enron in November 1992 as Vice President and General Counsel of Enron Power Corp.[5] He is also a member of the Advisory Board of the Texas Children's Cancer Center.

Mr. Walls is a member of PGE's Compensation Committee.

(1) As of February 28, 2005. Directors of PGE hold office until the next annual meeting of shareholders or until their respective successors are duly elected and qualified. James J. Piro resigned as a Director of PGE, effective January 31, 2004, but remains an Executive Officer of PGE. Raymond M. Bowen, Jr. resigned as a Director of PGE, effective October 1, 2004.

(2) Enron Corp. filed for bankruptcy protection on December 2, 2001.

(3) Portland General Holdings, Inc. filed for bankruptcy protection on June 27, 2003.

(4) Enron International Inc. filed for bankruptcy protection on May 19, 2003.

(5) Enron Power Corp. filed for bankruptcy protection on June 25, 2003.

Executive Officers of the Registrant[1]

Name	Age	Business Experience
Peggy Y. Fowler Chief Executive Officer and President	53	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	52	Appointed to current position on July 25, 2002. Served as Senior Vice President Finance, Chief

Executive Vice President, Finance, Chief Financial Officer and Treasurer				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		53		Appointed to current position on August 2, 2004. Served as Vice President, Human Resources and Information Technology 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) (Continued)

Name		Age		Business Experience
Carol A. Dillin Vice President, Public Policy		47		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 & Delivery		55		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		54		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 & Strategic Planning		48		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] (Continued)

Name		Age		Business Experience
James F. Lobdell Vice President, Power Operations & Resource Planning		46		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		57		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		62		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 & Power Supply/ Generation		57		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, 2005. Officers of PGE are elected for one-year terms or until their successors are elected and qualified. Christopher D. Ryder resigned as an Executive Officer of PGE, effective April 3, 2004.

(2) Portland General Holdings, Inc. filed for bankruptcy protection on June 27, 2003.

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 Portland General Electric Accounting and Financial Reporting Code of Ethics is publicly available on the Company's web site at www.portlandgeneral.com, About PGE, Corporate Information, Corporate Governance. 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 2004.

Item 11. Executive Compensation

Summary Compensation Table

The following indicates total compensation earned for the years ended December 31, 2004, 2003 and 2002 by the Chief Executive Officer and the four most highly compensated executive officers of PGE (the "Named Executive Officers").

		Annual Compensation		
				All Other
Name and Principal Position	Year	Salary(1)	Bonus	Compensation(2)
Peggy Y. Fowler	2004	$350,004	$376,744	$ 13,647
Chief Executive Officer	2003	350,004	240,000	413,792
and President	2002	345,836	200,000	433,192
James J. Piro	2004	$227,379	$138,857	$ 11,933
Executive Vice President, Finance	2003	215,129	160,000	136,970
Chief Financial Officer and Treasurer	2002	208,210	120,000	141,198
Douglas R. Nichols	2004	$193,336	$124,730	$ 10,719
Vice President, General Counsel	2003	190,008	138,000	119,716
and Secretary	2002	181,424	90,000	12,157
Stephen M. Quennoz	2004	$193,885	$115,815	$ 8,625
Vice President, Nuclear &	2003	191,411	130,000	8,688
Power Supply/Generation	2002	186,125	90,000	20,334
Stephen R. Hawke	2004	$178,336	$115,042	$ 9,619
Vice President, Customer Service & Delivery	2003	175,008	95,000	115,450
	2002	172,676	70,000	14,127

(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 Enron Corp. Savings Plan (401k) and the Management Deferred Compensation Plan (MDCP); (iii) payments made under retention agreements. The following are amounts for 2004:

	Split Dollar Insurance Cost	Contributions to 401(k) and MDCP	Total
Peggy Y. Fowler	$668	$12,979	$13,647
James J. Piro	-	11,933	11,933
Douglas R. Nichols	-	10,719	10,719
Stephen M. Quennoz	-	8,625	8,625
Stephen R. Hawke	-	9,619	9,619

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 level of $210,000 (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

		Years of Service				
	Final Average Earnings	15	20	25	30	35
Pension Plan Only	$210,000	$50,074	$66,766	$83,457	$100,148	$105,398
Pension Plan and SERP	700,000	-	-	-	446,250	472,500
	800,000	-	-	-	510,000	540,000

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 $210,000 or pay annual benefits in excess of $170,000. 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, 31; James J. Piro, 25; Douglas R. Nichols, 14; Stephen M Quennoz, 14; and, Stephen R. Hawke, 31. 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 2004, outside 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. In 2003, there were no compensation arrangements for, or fees paid to, Directors of PGE solely for their service as Directors.

The following table indicates total fees paid to outside directors for their Board service during 2004.

	Board Service Fees Paid		
Name	Directorship	Chair	Total

John W. Ballantine	$73,187	$ -	$73,187
(director since February 1, 2004)			
Corbin A. McNeill, Jr.	73,187	18,297	91,484
(director since February 1, 2004)			
Raymond S. Troubh	60,000	-	60,000
(director since April 1, 2004)			

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 are John W. Ballantine, Robert S. Bingham, and Robert H. Walls, Jr. Salary increases, annual incentive awards, and long-term incentive grants (if any) are reviewed annually to ensure consistency with PGE's total compensation philosophy. During 2004, no executive officer of the Company served as a director or as a member of the compensation committee of another company who had an executive officer that served as a member of the Compensation Committee or as a director of the Company.

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

As previously reported in PGE's 2003 SEC Form 10-K, the Audit Committee of the Board of Directors of PGE dismissed PricewaterhouseCoopers LLP (PwC) as PGE's independent auditors on January 9, 2004. On January 12, 2004, Deloitte & Touche LLP (Deloitte & Touche) was engaged as PGE's new independent auditors.

The Company incurred the following fees for services rendered by PwC and Deloitte & Touche for the years ended December 31, 2004 and 2003.

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, 2004 and 2003 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 providing comfort letters and assistance with and review of documents filed with the SEC. Fees for 2004 for PwC relate to services provided to consent to the inclusion of their audit report on the 2002 consolidated financial statements included in this Form 10-K.

	PwC			Deloitte & Touche	
2004	$ 30,000			$760,000	
2003	395,368	(a)		888,585	(a)

(a) 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 Enron auction process for PGE, attest services that are not required by statute or regulation, and consultations concerning financial accounting and reporting standards.

	PwC		Deloitte &

			Touche
2004	$ 720		$129,856
2003	137,183		-

Tax Fees

Tax Fees billed in the year indicated for professional tax services related to the potential sale of the Company are set forth below.

	PwC		Deloitte & Touche
2004	$ -		$ -
2003	2,975		-

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 include tax compliance and financial accounting reference products and services.

	PwC		Deloitte & Touche
2004	$ -		$ 16,373
2003	-		-

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.

We have been advised by Deloitte & Touche that substantially all of the work performed in conjunction with its audit of PGE's financial statements for the year 2004 was rendered by permanent full time employees and partners of Deloitte & Touche.

Part IV

Item 15. Exhibits and Financial Statement Schedules

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

Financial Statement Schedule

Exhibits

See Exhibit Index on Page ExhibitsIndex

147 of this report.

Portland General Electric Company and Subsidiaries

Schedule II - Consolidated Valuation and Qualifying Accounts

For the Years Ended December 31, 2004, 2003, and 2002

(In Millions)

		Allowance for Uncollectible Accounts
Balance at January 1, 2002	$	102
Provision charged to income		16
Amounts written off, less recoveries		(9)
Balance at December 31, 2002		109
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

(*) Includes $76 million reversal of provisions recorded in prior years, related to a December 2004 distribution to Enron. See Note 13, Related Party Transactions, for further information.

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 11, 2005		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		Chief Executive Officer		March 11, 2005
Peggy Y. Fowler		and President and Director		

/s/ James J. Piro		Executive Vice President, Finance		March 11, 2005
James J. Piro		Chief Financial Officer and		
		Treasurer		

/s/ Kirk M. Stevens		Controller and		March 11, 2005
Kirk M. Stevens		Assistant Treasurer		

*John W. Ballantine	Director	March 11, 2005
*Robert S. Bingham	Director	March 11, 2005
*Corbin A. McNeill, Jr.	Director	March 11, 2005
*Raymond S. Troubh	Director	March 11, 2005
*Robert H. Walls, Jr.	Director	March 11, 2005

	*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	*	Portland General Electric Company Management Deferred Compensation Plan, dated March 12, 2003 [Form 10-Q for the quarter ended March 31, 2003, Exhibit (10)].

10.18		Portland General Electric Company 2005 Management Deferred Compensation Plan, dated March 4, 2005 (filed herewith).
10.19	*	Portland General Electric Company Supplemental Executive Retirement Plan, dated March 12, 2003 [Form 10-Q for the quarter ended March 31, 2003, Exhibit (10)].
10.20	*	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)].
10.21	*	Portland General Electric Company Umbrella Trust for Management, dated March 12, 2003 [Form 10-Q for the quarter ended March 31, 2003, Exhibit (10)].
10.22	*	Director Compensation Arrangement [Form 10-K for the fiscal year ended December 31, 2003, Exhibit (10)].
(16)		**Letter re: change in Certifying Accountant**
16.1	*	PricewaterhouseCoopers LLP Letter dated January 20, 2004 [Form 8-K/A, January 9, 2004 - Item 4. Changes in Registrant's Certifying Accountant]
(24)		**Power of Attorney**
24.1		Power of Attorney (filed herewith).

PORTLAND GENERAL ELECTRIC COMPANY

AND SUBSIDIARIES

EXHIBIT INDEX

Number		Exhibit
(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** 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 10.18

PORTLAND GENERAL ELECTRIC COMPANY

2005 MANAGEMENT DEFERRED COMPENSATION PLAN

Effective as of January 1, 2005

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PORTLAND GENERAL ELECTRIC COMPANY

2005 MANAGEMENT DEFERRED COMPENSATION PLAN

ARTICLE I

PURPOSE

1.1 Purpose

The purpose of this 2005 Management Deferred Compensation Plan is to provide elective deferred compensation in excess of the limits on elective deferrals under qualified cash or deferred arrangements. It is intended that the Plan will aid in attracting and retaining personnel of exceptional ability.

The Plan is intended (1) to comply with section 409A of the Internal Revenue Code of 1986, as amended (the "Code") and official guidance issued thereunder, and (2) to be "a plan which is unfunded and is maintained by an employer primarily for the purpose of providing deferred compensation for a select group of management or highly compensated employees" within the meaning of sections 201(2), 301(a)(3) and 401(a)(1) of the Employee Retirement Income Security Act of 1974, as amended ("ERISA"). Notwithstanding any other provision of this Plan, this Plan shall be interpreted, operated and administered in a manner consistent with these intentions.

1.2 Effective Date

Prior to January 1, 2005, the Portland General Electric Company (the "Company") maintained the Management Deferred Compensation Plan, which was frozen as of December 31, 2004. The Plan is hereby established by the Company effective January 1, 2005 and is intended to replace the frozen plan on a prospective basis.

1.3 Plan Sponsor

The Plan is adopted for the benefit of selected employees of the Company and selected employees of any corporations or other entities affiliated with or subsidiary to it, if such corporations or entities are selected by the Board. **The Company assumes no liability for the payment of any Plan benefit owed by any other Participating Employer, as defined herein, by reason of its Plan sponsorship.**

ARTICLE II

DEFINITIONS

2.1 Account

"Account" means the account maintained by a Participating Employer in accordance with ARTICLE IV with respect to any deferral of Compensation or Paid Time Off Cancellation pursuant to this Plan.

2.2 Administrative Committee

"Administrative Committee" means the persons designated by the Board to administer the Plan.

2.3 Base Salary

"Base Salary" means the Eligible Employee's actual base pay in the pay period and, except as provided herein, excluding any bonuses and/or overtime pay.

2.4 Beneficiary

"Beneficiary" means the person, persons or entity entitled under ARTICLE VII to receive any Plan benefits payable after a Participant's death.

2.5 Board

"Board" means the Board of Directors of Portland General Electric Company.

2.6 Bonuses

"Bonuses" means Corporate Incentive Plan Awards, Notable Achievement Awards, and any other form of cash Incentive Compensation explicitly designated as deferrable pursuant to this Plan by the Deferral Election form approved by the Administrative Committee.

2.7 Company

"Company" means Portland General Electric Company, an Oregon corporation.

2.8 Code

"Code" means the Internal Revenue Code of 1986, as amended.

2.9 Compensation

"Compensation" means the total of the following, before reduction for elective deferrals under this Plan or a Participating Employer's tax qualified retirement savings plan or any other flexible benefit plan:

2.9-1 Base Salary;

2.9-2 Bonuses;

2.9-3 Any interest on the above payments credited by a Participating Employer for the benefit of an Eligible Employee prior to the date of payment, without respect to any deferral of Compensation made pursuant to this Plan, by a Participating Employer.

Compensation, for purposes of this Plan, may include any new form of cash remuneration paid by a Participating Employer to any Eligible Employee which is explicitly designated as deferrable pursuant to this Plan by the Deferral Election form approved by the Administrative Committee. Compensation for purposes of this Plan, does not include expense reimbursements, imputed income, or any form of noncash compensation or benefits.

2.10 Compensation Committee

"Compensation Committee" means the Compensation Committee of the Board.

2.11 Deferral Election

"Deferral Election" means the election completed by Participant in a form approved by the Administrative Committee which indicates Participant's irrevocable election to defer Compensation as designated in the Deferral Election, pursuant to ARTICLE III.

2.12 Determination Date

"Determination Date" means the last day of each calendar month.

2.13 Direct Subsidiary

"Direct Subsidiary" means any corporation of which a Participating Employer owns at least eighty percent (80%) of the total combined voting power of all classes of its stock entitled to vote.

2.14 Eligible Employee

"Eligible Employee" means an employee of a Participating Employer who:

2.14-1 Is exempt;

2.14-2 Is not covered by a collective bargaining agreement; and

2.14-3 If employed for the entire calendar year, receives or, is expected to receive, Base Salary and an annual bonus from one or more Participating Employers in the calendar year, in an amount equal to or in excess of the threshold amount described in 2.14-5 below, or

2.14-4 If employed for a part of the calendar year, receives or, based on an annualized level of pay would have received, Base Salary and an annual bonus from one or more Participating Employers in the calendar year, in an amount equal to or in excess of the threshold amount described in 2.14-5 below. Notwithstanding the above, eligibility is at the discretion of the Administrative Committee.

2.14-5 The threshold amount in calendar year 2005 and any subsequent year shall be one hundred and twenty-five thousand dollars ($125,000). Such amount may be adjusted by the Administrative Committee each subsequent calendar year at the same time and in not less than the percentage ratio as the cost of living adjustment in the dollar limit on defined benefits under Code section 415(d).

2.15 ERISA

"ERISA" means the Employee Retirement Income Security Act of 1974, as amended.

2.16 Incentive Compensation

"Incentive Compensation" means payments made to a Participant in recognition of meritorious work performance but shall not include, without limitation, any payment received as moving expense, mortgage expense or mortgage interest reimbursement.

2.17 Indirect Subsidiary

"Indirect Subsidiary" means any corporation of which a Participating Employer directly and constructively owns at least eighty percent (80%) of the total combined voting power of all classes of its stock entitled to vote. In determining the amount of stock of a corporation that is constructively owned by a Participating Employer, stock owned, directly or constructively, by a corporation shall be considered as being owned proportionately by its shareholders according to such shareholders' share of voting power of all classes of its stock entitled to vote.

2.18 Interest

"Interest" means the interest yield computed at the monthly equivalent of an annual yield that is one-half (0.5) percentage point higher than the annual yield on Moody's Average Corporate Bond Yield Index for the three (3) calendar months preceding the immediately prior month as published by Moody's Investors Service, Inc. (or any successor thereto), or, if such index is no longer published, a substantially similar index selected by the Board.

2.19 Key Employee

"Key Employee" means an Employee treated as a "specified employee" under Code section 409A(a)(2)(B)(i), i.e., a key employee (as defined in Code section 416(i) without regard to paragraph (5) thereof) of a corporation any stock in which is publicly traded on an established securities market or otherwise.

2.20 Paid Time Off

"Paid Time Off" means those vacation and holiday days for which the Employer pays employees for time not worked.

2.21 Paid Time Off Cancellation

"Paid Time Off Cancellation" means cash payments made in lieu of Paid Time Off earned by an Eligible Employee.

2.22 Participant

"Participant" means any Eligible Employee who has elected to make deferrals under this Plan.

2.23 Participating Employer

"Participating Employer" means the Company or any affiliated or subsidiary company designated by the Board as a Participating Employer under the Plan, as long as such designation has become effective and continues to be in effect. The designation as a Participating Employer shall become effective only upon the acceptance of such designation and the formal adoption of the Plan by a Participating Employer. A Participating Employer may revoke its acceptance of designation as a Participating Employer at any time, but until it makes such revocation, all of the provisions of this Plan and any amendments thereto shall apply to the Eligible Employees of the Participating Employer and their Beneficiaries.

2.24 Pension Plan

"Pension Plan" means the Participating Employer's Pension Plan, as may be amended from time to time, and any successor defined benefit retirement income plan or plans maintained by the Participating Employer which qualify under Code section 401(a).

2.25 Plan

"Plan" means the Portland General Electric Company 2005 Management Deferred Compensation Plan, as may be amended from time to time.

2.26 Policies

"Policies" means any life insurance policies, annuity contracts or the proceeds therefrom owned or which may be acquired by Participating Employer.

2.27 President

"President" means the President of the Company.

2.28 Separation from Service or Separate from Service means a "separation from service" within the meaning of Code section 409A. Generally, a separation from service occurs when an individual ceases to provide services for the Company and any corporations or other entities that are treated as a single employer with the Company under Code section 414.

2.29 Unforeseeable Emergency

"Unforeseeable Emergency" means a severe financial hardship to a Participant resulting from an illness or accident of the Participant, the Participant's spouse, or a dependent (as defined in Code section 152(a)) of the Participant, loss of the Participant's property due to casualty, or other similar extraordinary and unforeseeable circumstances arising as a result of events beyond the control of the Participant.

ARTICLE III

ELIGIBILITY AND DEFERRALS

3.1 Eligibility

3.1-1 General. An Eligible Employee who has completed one year of continuous employment with one or more Participating Employers shall be eligible to participate by making a Deferral Election under Section 3.2 below. The Administrative Committee shall notify Eligible Employees about the Plan and the benefits provided under it. The requirement of one year of continuous employment may be waived by the Administrative Committee.

3.1-2 Cessation of Eligibility. An Eligible Employee who ceases to be an employee of a Participating Employer or to satisfy condition 2.14-1, 2.14-2 or 2.14-3 of the definition of Eligible Employee shall cease participating as to new deferrals immediately.

3.2 Deferral Elections

3.2-1 Time of Elections. An Eligible Employee may elect to participate in the Plan with respect to any Compensation and/or Paid Time Off Cancellation designated in a Deferral Election in a form approved by the Administrative Committee. The Deferral Election must be filed with the Administrative Committee no later than December 15 of the year preceding the year in which the Compensation and/or Paid Time Off Cancellation is earned, or such shorter period as is designated in the Deferral Election form, provided all such elections must be made by the deadline imposed by Code section 409A. A Deferral Election for a new form of cash remuneration may be made at such other time before a Participant becomes entitled to receipt thereof, as may be approved by the Administrative Committee and within the deadline imposed by Code section 409A.

3.2-2 Mid-Year Eligibility. If an individual first becomes eligible to participate during a calendar year and wishes to defer Compensation and/or Paid Time Off Cancellation during the remainder of the year, a Deferral Election may be filed no later than thirty (30) days after becoming eligible to participate in the Plan. Such Deferral Election shall be effective only with regard to Compensation and/or Paid Time Off Cancellation earned after it is filed with the Administrative Committee and otherwise to the extent permitted by Code section 409A.

3.2-3 Performance-based Compensation. Notwithstanding the foregoing, if the Administrative Committee determines that an item of Compensation qualifies as "performance-based compensation" under Code section 409A, an Eligible Employee may elect to defer a portion of the performance-based compensation by filing a Deferral Election at such later time as permitted by the Administrative Committee and permitted under Code section 409A.

3.2-4 Irrevocability. A Deferral Election for amounts earned in the following calendar year shall become irrevocable on the December 15 by which it is due under Section 3.2-1 and a Deferral Election for amounts earned in the current calendar year shall become irrevocable upon filing with the Administrative Committee under Section 3.2-2 or, if applicable, Section 3.2-3.

3.2-5 Transfer to a Participating Employer. If a Participant transfers employment from one Participating Employer to another Participating Employer, the Participant's Deferral Election shall remain in effect for the remainder of the calendar year with respect to Compensation and/or Paid Time Off Cancellation earned by the individual after the transfer to the new Participating Employer.

3.3 Limits on Elective Deferrals

A Participant may elect to defer up to eighty percent (80%) of Base Salary and up to one hundred percent (100%) of Bonuses or other form of cash remuneration as approved by the Administrative Committee. The level of deferral elected in either case must be in one percent (1%) increments. A Participant may elect to defer up to one hundred twenty (120) hours per year of Paid Time Off Cancellation in one-tenth (1/10) hour increments, but may not defer any Paid Time Off Cancellation earned in prior calendar years, or the first two hundred (200) hours of Paid Time Off Cancellation earned in the calendar year to which the Deferral Election relates.

3.4 Matching Contributions

The Participating Employer shall provide a matching contribution for each Participant who is making deferrals of Base Salary under this Plan. The matching contribution shall be three percent (3%) of the Participant's annual elective Base Salary deferral under this Plan. For purposes of this provision, Base Salary shall not include amounts received as a Nuclear Regulatory Commission licensing bonus.

3.5 Welfare Benefits

Compensation deferred under this Plan shall constitute compensation for purposes of any welfare plans, (as defined by ERISA), sponsored by the Participating Employer.

ARTICLE IV

DEFERRED COMPENSATION ACCOUNT

4.1 Crediting to Account

The amount of the elective deferrals and matching contributions for a Participant under this Plan shall be credited to an Account for the Participant on the books of the Participating Employer at the time the Compensation and/or Paid Time Off Cancellation would have been paid in cash. Any taxes or other amounts due from the Participant with respect to the deferred Compensation under federal, state or local law, such as a Participant's share of FICA, shall be withheld from nondeferred Compensation payable to the Participant at the time the deferred amounts are credited to the Account. If at the time of such credit, there is not sufficient nondeferred compensation to make the required tax withholding, the amount deferred shall be reduced to allow the Company to comply with the tax withholding required.

4.2 Determination of Accounts

The last day of each calendar month shall be a Determination Date. Each Participant's Account as of each Determination Date shall consist of the balance of the Account as of the immediately preceding Determination Date, plus the Participant's elective deferrals, matching contributions, and Interest credited under this Plan, minus the amount of any distributions made from this Plan since the immediately preceding Determination Date. Interest credited shall be calculated as of each Determination Date based upon the average daily balance of the Account since the preceding Determination Date.

4.3 Vesting of Accounts

Account balances in this Plan shall be fully vested at all times.

4.4 Statement of Accounts

The Administrative Committee shall submit to each Participant, after the close of each calendar quarter and at such other times as determined by the Administrative Committee a statement setting forth the balance of the Account maintained for the Participant.

ARTICLE V

PLAN BENEFITS

5.1 Benefits

5.1-1 Entitlement to Benefits at Separation from Service. Benefits under this Plan shall be payable to a Participant on Separation from Service, or on such subsequent date elected by a Participant and approved by the Administrative Committee on the Participant's Deferral Election. The amount of the benefit shall be the balance of the Participant's Account including Interest to the date of payment, in the form elected under Section 5.3 below.

Notwithstanding the above or any other provision of this Plan, distributions may not be made to a Key Employee upon a Separation from Service before the date which is six months after the date of the Key Employee's Separation from Service (or, if earlier, the date of death of the Key Employee).

5.1-2 Entitlement to Benefits at Death. As soon as administratively practicable following the death of a Participant for whom an Account is held under this Plan, a death benefit shall be payable to the Participant's Beneficiary in the same form as the Participant elected for payments at Separation from Service, under Section 5.3 below. The amount of the benefit shall be the balance of the Participant's Account including Interest to the date of payment.

5.2 Withdrawals for Unforeseeable Emergency

A Participant may withdraw all or any portion of his Account balance for an Unforeseeable Emergency. The amounts distributed with respect to an Unforeseeable Emergency may not exceed the amounts necessary to satisfy such Unforeseeable Emergency plus amounts necessary to pay taxes reasonably anticipated as a result of the distribution, after taking into account the extent to which such hardship is or may be relieved through reimbursement or compensation by insurance or otherwise or by liquidation of the Participant's assets (to the extent the liquidation of such assets would not itself cause severe financial hardship).

5.2-1 Determination. The existence of an Unforeseeable Emergency and the amount to be withdrawn shall be determined by the Administrative Committee.

5.2-2 Suspension. A Participant who makes a withdrawal for Unforeseeable Emergency or financial hardship from any company-sponsored deferral plan, whether qualified or nonqualified, shall be suspended from participation in this Plan for twelve (12) months from the date of such withdrawal, to the extent such suspension is permissible under Code section 409A. Compensation and/or Paid Time Off Cancellation payable during such suspension that would have been deferred under this Plan shall instead be paid to the Participant. No matching contribution shall be credited to a Participant's Account under this Plan during any period of suspension.

5.3 Form of Benefit Payment

5.3-1 The Plan benefits attributable to the elective deferrals for any calendar year shall be paid in one of the forms set out below, as elected by the Participant in the form of payment designation filed with the Deferral Election for that year. The forms of benefit payment are:

(a) A lump-sum payment;

(b) Monthly installment payments in substantially equal payments of principal and Interest over a period of up to one hundred eighty (180) months. The amount of the installment payment shall be redetermined on the first day of the month coincidental with or next following the anniversary of the date of Separation from Service each year, based upon the then current rate of Interest, the remaining Account balance, and the remaining number of payment periods; or

(c) For Participants designated by the President to the Administrative Committee, monthly installment payments over a period of up to one hundred eighty (180) months, consisting of interest only payments for up to one hundred twenty (120) months and principal and interest payments of the remaining Account balance over the remaining period. The amount of the installment payment shall be redetermined on the first day of the month coincidental with or next following the anniversary of the date of Separation from Service each year, based upon the then current rate of Interest, the remaining Account balance, and the remaining number of payment periods.

(d) In the event the Account balance is ten thousand dollars ($10,000) or less, that benefit will be paid out in a lump sum notwithstanding the form of benefit payment elected by the Participant.

5.3-2 A Participant may elect to file a change of payment designation which shall supersede all prior form of payment designations with respect to the Participant's entire Account. The Participant may redesignate a combination of lump sum and monthly installments if approved by the Administrative Committee, but only if such redesignation does not result in an acceleration of payments under Code section 409A. Any change of payment designation must comply with Code section 409A, which generally means that the designation must (1) not take effect until at least twelve (12) months after the date of the change of payment designation, (2) provide an additional deferral for the first payment for a period of at least five years from the date such payment would otherwise have been made, except in the case of elections relating to distributions on death or Unforeseeable Emergency, and (3) if related to a payment at a specified time or pursuant to a fixed schedule, be made at least tw elve (12) months prior to the date of the first scheduled payment.

5.3-3 Participants designated by the President to the Administrative Committee may elect to file a change of payment designation which shall supersede all prior form of payment designations with respect to the Participant's entire Account. The Participant may redesignate monthly installment payments over a period of up to one hundred eighty (180) months, consisting of interest only payments for up to one hundred twenty (120) months and principal and interest payments of the remaining Account balance over the remaining period, but only if such redesignation does not result in an acceleration of payments under Code section 409A. To be effective, such designation must be approved by the President and the Administrative Committee. Any change of payment designation must comply with Code section 409A, which generally means that the designation must (1) not take effect until at least twelve (12) months after the date of the change of payment designation, (2) provide an additional deferral for the first payment for a period of at least five years from the date such payment would otherwise have been made, except in the case of elections relating to distributions on death or Unforeseeable Emergency, and (3) if related to a payment at a specified time or pursuant to a fixed schedule, be made at least twelve (12) months prior to the date of the first scheduled payment.

5.4 Withholding; Payroll Taxes

Each Participating Employer shall withhold from payments made hereunder any taxes required to be withheld from a Participant's wages for the federal or any state or local government. Withholding shall also apply to payments to a Beneficiary unless an election against withholding is made under Code section 3405(a)(2).

5.5 Commencement of Payments

Subject to the rule for Key Employees in Section 5.1-1, payment shall commence as soon as administratively practicable, but not later than sixty-five (65) days after the end of the month in which a Participant Separates from Service unless the Participant's Deferral Election, approved by the Administrative Committee, provides for a later commencement date. All payments shall be made as of the first day of the month, and shall commence within the time required by section 409A.

5.6 Full Payment of Benefits

Notwithstanding any other provision of this Plan, all benefits shall be paid no later than one hundred eighty (180) months following the date payment to a Participant commences.

5.7 Payment to Guardian

If a Plan benefit is payable to a minor or a person declared incompetent or deemed to be legally incapable of handling the disposition of property, the Administrative Committee may direct payment of such Plan benefit to the guardian, legal representative or person having the care and custody of such minor or incompetent person. The Administrative Committee may require such proof of incompetency, minority, incapacity or guardianship as he may deem appropriate prior to distribution of the Plan benefit. Such distribution shall completely discharge the Administrative Committee, the Participating Employer, and the Company from all liability with respect to such benefit.

ARTICLE VI

RESTORATION OF PENSION PLAN BENEFITS

6.1 Pension Plan

If a Participating Employer maintains a tax qualified Pension Plan for the benefit of eligible employees, and the Pension Plan provides benefits determined under a formula that is based in part on the employee's nondeferred compensation, a Participant in this Plan may receive a smaller benefit under the Pension Plan as a result of electing deferrals under this Plan.

6.2 Restoration of Pension Plan Benefits

In addition to the benefits payable under Section 5.1 above, a Participating Employer shall pay to any Participant whose Pension Plan benefit is not restored under any other employee or executive benefit plan maintained by a Participating Employer, a benefit payment equal to the excess of (b) over (a) as follows:

(a) The actuarial equivalent lump sum present value of the retirement income (or death benefit) payable (either immediately or deferred) under the Pension Plan; and

(b) the actuarial equivalent lump sum present value of the retirement income (or death benefit) that would have been payable under the Pension Plan if Participant had made no Deferral Elections in any calendar year under this Plan. The actuarial equivalent lump sum present values shall be calculated in the same manner and using the same factors as are used to calculate lump-sum distributions under the Pension Plan. If Participant Separates from Service prior to attaining the age of fifty-five (55), payment of the restoration of Pension Plan benefits shall be made as if Participant had made a lump-sum election pursuant to Subsection (a) above with respect to the payment of the restoration of Pension Plan benefits. If Participant Separates from Service upon or after attaining the age of fifty-five (55), payment of the restoration of Pension Plan benefits shall be made as if Participant had made an election to receive monthly installment payments in substantially equal payments of principal and Interest over a period of one hundred twenty (120) months pursuant to Section 5.3-1(b) above with

respect to the payment of the restoration of Pension Plan benefits. Notwithstanding the foregoing, in the event the actuarial equivalent lump sum present value is ten thousand dollars ($10,000) or less when the Participant Separates from Service, that benefit will be paid out in a lump sum.

ARTICLE VII

BENEFICIARY DESIGNATION

7.1 Beneficiary Designation

Each Participant shall have the right, at any time, to designate one or more persons or entities as the Participant's Beneficiary, primary as well as secondary, to whom benefits under this Plan shall be paid in the event of the Participant's death prior to complete distribution to the Participant of the benefits due under the Plan. Each Beneficiary designation shall be in a written form prescribed by the Administrative Committee and will be effective only when filed with the Administrative Committee during the Participant's lifetime.

7.2 Amendments

Any Beneficiary designation may be changed by a Participant without the consent of any Beneficiary by filing a new Beneficiary designation with the Administrative Committee. If a Participant's compensation is community property under applicable law, any Beneficiary designation shall be valid or effective only as permitted under such a law.

7.3 No Beneficiary Designation

In the absence of an effective Beneficiary designation, or if all Beneficiaries predecease a Participant, the Participant's estate shall be the Beneficiary. If a Beneficiary dies after a Participant and before payment of benefits under this Plan has been completed, the remaining benefits shall be payable to the Beneficiary's estate.

7.4 Effect of Payment

Payment to the Beneficiary shall completely discharge the Participating Employer's obligations under this Plan.

ARTICLE VIII

ADMINISTRATION

8.1 Administrative Committee; Duties

This Plan shall be administered by the Administrative Committee appointed by the Board. Members of the Administrative Committee may be Participants under this Plan who are actively employed by the Company. The Administrative Committee shall have the authority to make, amend, interpret, and enforce all appropriate rules and regulations for the administration of this Plan and decide or resolve any and all questions, including interpretations of this Plan, as may arise in connection with the Plan. The Administrative Committee shall report to the Compensation Committee regarding Plan activity on an annual basis and at such other times as may be requested by the Compensation Committee.

8.2 Agents

In the administration of this Plan, the Administrative Committee may, from time to time, employ agents and delegate to such agents, including employees of any Participating Employer, such administrative duties as it sees fit, and may from time to time consult with counsel, who may be counsel to any Participating Employer.

8.3 Binding Effect of Decisions

The decision or action of the Administrative Committee in respect of any question arising out of or in connection with the administration, interpretation and application of the Plan and the rules and regulations promulgated hereunder shall be final and conclusive and binding upon all persons having any interest in the Plan.

8.4 Indemnity of Administrative Committee; Compensation Committee

Each Participating Employer shall indemnify and hold harmless the Administrative Committee and the Compensation Committee, and their individual members, against any and all claims, loss, damage, expense or liability arising from any action or failure to act with respect to this Plan, except in the case of gross negligence or willful misconduct.

8.5 Availability of Plan Documents

Each Participant shall receive a copy of this Plan, and the Administrative Committee shall make available for inspection by any Participant a copy of the rules and regulations used in administering the Plan.

8.6 Cost of Plan Administration

The Company shall bear all expenses of administration of this Plan. However, a ratable portion of the expense shall be charged back to each Participating Employer.

ARTICLE IX

CLAIMS PROCEDURE

9.1 Claim

A Participant or his authorized representative may file a claim for benefits under the Plan. Any claim must be in writing and submitted to the Administrative Committee at such address as may be specified from time to time. Claimants will be notified in writing of approved claims, which will be processed as filed. A claim is considered approved only if its approval is communicated in writing to a claimant.

9.2 Denial of Claim

In the case of the denial of a claim respecting benefits paid or payable with respect to a Participant, a written notice will be furnished to the claimant within 90 days of the date on which the claim is received by the Administrative Committee. If special circumstances (such as for a hearing) require a longer period, the claimant will be notified in writing, prior to the expiration of the 90-day period, of the reasons for an extension of time; provided, however, that no extensions will be permitted beyond 90 days after the expiration of the initial 90-day period. A denial or partial denial of a claim will be dated and signed by the Administrative Committee and will clearly set forth:

(i) the specific reason or reasons for the denial;

(ii) specific reference to pertinent Plan provisions on which the denial is based;

(iii) a description of any additional material or information necessary for the claimant to perfect the claim and an explanation of why such material or information is necessary; and

(iv) an explanation of the procedure for review of the denied or partially denied claim set forth below, including the claimant's right to bring a civil action under ERISA section 502(a) following an adverse benefit determination on review.

9.3 Review of Claim

Upon denial of a claim, in whole or in part, a claimant or his duly authorized representative will have the right to submit a written request to the Administrative Committee for a full and fair review of the denied claim by filing a written notice of appeal with the Administrative Committee within 60 days of the receipt by the claimant of written notice of the denial of the claim. A claimant or the claimant's authorized representative will have, upon request and free of charge, reasonable access to, and copies of, all documents, records, and other information relevant to the claimant's claim for benefits and may submit issues and comments in writing. The review will take into account all comments, documents, records, and other information submitted by the claimant relating to the claim, without regard to whether such information was submitted or considered in the initial benefit determination.

If the claimant fails to file a request for review within 60 days of the denial notification, the claim will be deemed abandoned and the claimant precluded from reasserting it. If the claimant does file a request for review, his request must include a description of the issues and evidence he deems relevant. Failure to raise issues or present evidence on review will preclude those issues or evidence from being presented in any subsequent proceeding or judicial review of the claim.

9.4 Decision Upon Review

The Administrative Committee will provide a prompt written decision on review. If the claim is denied on review, the decision shall set forth:

(i) the specific reason or reasons for the adverse determination;

(ii) specific reference to pertinent Plan provisions on which the adverse determination is based;

(iii) a statement that the claimant is entitled to receive, upon request and free of charge, reasonable access to, and copies of, all documents, records, and other information relevant to the claimant's claim for benefits; and

(iv) a statement describing any voluntary appeal procedures offered by the Plan and the claimant's right to obtain the information about such procedures, as well as a statement of the claimant's right to bring an action under ERISA section 502(a).

A decision will be rendered no more than 60 days after the Administrative Committee's receipt of the request for review, except that such period may be extended for an additional 60 days if the Administrative Committee determines that special circumstances (such as for a hearing) require such extension. If an extension of time is required, written notice of the extension will be furnished to the claimant before the end of the initial 60-day period.

9.5 Finality of Determinations; Exhaustion of Remedies

To the extent permitted by law, decisions reached under the claims procedures set forth in this Article shall be final and binding on all parties. No legal action for benefits under the Plan shall be brought unless and until the claimant has exhausted his remedies under this Article. In any such legal action, the claimant may only present evidence and theories which the claimant presented during the claims procedure. Any claims which the claimant does not in good faith pursue through the review stage of the procedure shall be treated as having been irrevocably waived.

ARTICLE X

AMENDMENT AND TERMINATION OF PLAN

10.1 Amendment

The Administrative Committee may amend the Plan from time to time as may be necessary for administrative purposes and legal compliance of the Plan, provided, however, that no such amendment shall affect the benefit rights of Participants or Beneficiaries in the Plan. The Compensation Committee may amend the Plan at any time, provided, however, that no amendment shall be effective to decrease or restrict the accrued rights of Participants and Beneficiaries to the amounts in their Accounts at the time of the amendment. Such amendments shall be subject to the following:

10.1-1 Preservation of Account Balance. No amendment shall reduce the amount accrued in any Account to the date such notice of the amendment is given.

10.1-2 Changes in Interest Rate. No amendment shall reduce the rate of Interest to be credited, after the date of the amendment, on the amount already accrued in any Account or on the deferred amounts credited to any Account under Deferral Elections already in effect on the date of the amendment.

10.2 Termination

The board of directors of each Participating Employer may at any time, in its sole discretion, terminate or suspend the Plan in whole or in part for that Participating Employer. However, no such termination or suspension shall adversely affect the benefits of Participants which have accrued prior to such action, the benefits of any Participant who has previously Separated from Service, the benefits of any Beneficiary of a Participant who has previously died, or already accrued Plan liabilities between Participating Employers.

10.3 Payment at Termination

If the Plan is terminated, payment of each Account to a Participant or a Beneficiary for whom it is held shall commence pursuant to Section 5.5 and be paid in the form designated by the Participant, to the extent permitted under Code section 409A.

ARTICLE XI

MISCELLANEOUS

11.1 Legal Determinations

11.1-1 Compliance with Code. This Plan is intended to comply with Code section 409A and official guidance issued thereunder. Notwithstanding any other provision of this Plan, this Plan shall be interpreted, operated, and administered to achieve this intent.

11.1-2 Unfunded Plan. This Plan is intended to be an unfunded plan maintained primarily to provide deferred compensation benefits for a select group of "management or highly compensated employees" within the meaning of sections 201, 301, and 401 of ERISA, and therefore to be exempt from the provisions of Parts 2, 3 and 4 of Title I of ERISA. Accordingly, the Administrative Committee may terminate the Plan and commence termination payout under Section 10.3 above for all or certain Participants, to the extent permitted under Code section 409A, or remove certain employees as Participants, if the United States Department of Labor or a court of competent jurisdiction determines that the Plan constitutes an employee pension benefit plan within the meaning of section 3(2) of ERISA which is not so exempt. This Plan is not intended to create an investment contract, but to provide retirement benefits to eligible individuals who have elected to participate in the Plan. Eligible individu als are select employees who, by virtue of their position with a Participating Employer, are uniquely informed as to the Participating Employer's operations and have the ability to materially affect the Participating Employer's profitability and operations.

11.2 Liability

11.2-1 Liability for Benefits. Except as otherwise provided in this paragraph, liability for the payment of a Participant's benefit pursuant to this Plan shall be borne solely by the Participating Employer that employs the Participant and reports the Participant as being on its payroll during the accrual or increase of the Plan benefit, and no liability for the payment of any Plan benefit shall be incurred by reason of Plan sponsorship or participation except for the Plan benefits of a Participating Employer's own employees. Provided, however, that each Participating Employer, by accepting the Board's designation as a Participating Employer under the Plan and formally adopting the Plan, agrees to assume secondary liability for the payment of any benefit accrued or increased while a Participant is employed and on the payroll of a Participating Employer that is a Direct Subsidiary or Indirect Subsidiary of the Participating Employer at the time such benefit is accrued or incr eased. Such liability shall survive any revocation of designation as a Participating Employer with respect to any liabilities accrued at the time of such revocation. Nothing in this paragraph shall be interpreted as prohibiting any Participating Employer or any other person from expressly agreeing to the assumption of liability for a Plan Participant's payment of any benefits under the Plan.

11.2-2 Unsecured General Creditor. Participants and their Beneficiaries, heirs, successors, and assigns shall have no secured legal or equitable rights, interest or claims in any property or assets of a Participating Employer, nor shall they be beneficiaries of, or have any rights, claims or interests in any Policies or the proceeds therefrom owned or which may be acquired by a Participating Employer. Except as provided in Section 11.3, such Policies or other assets of a Participating Employer shall not be held under any trust for the benefit of Participants, their Beneficiaries, heirs, successors or assigns, or held in any way as collateral security for the fulfilling of the obligations of a Participating Employer under this Plan. Any and all of a Participating Employer's assets and Policies shall be, and remain, the general, unpledged, unrestricted assets of the Participating Employer. A Participating Employer's obligation under the Plan shall be that of an unfunded and unsecured promise to pay money in the future.

11.3 Trust Fund

At its discretion, each Participating Employer, jointly or severally, may establish one or more trusts, with such trustee as the Board may approve, for the purpose of providing for the payment of such benefits. Such trust or trusts may be irrevocable, but the assets thereof shall be subject to the claims of the Participating Employer's creditors. To the extent any benefits provided under the Plan are actually paid from any such trust, the Participating Employer shall have no further obligation with respect thereto, but to the extent not so paid, such benefits shall remain the obligation of, and shall be paid by the Participating Employer.

11.4 Nonassignability

Neither a Participant nor any other person shall have any right to sell, assign, transfer, pledge, anticipate, mortgage or otherwise encumber, hypothecate or convey in advance of actual receipt the amounts, if any, payable hereunder, or any part thereof, which are, and all rights to which are, expressly declared to be nonassignable and nontransferable. No part of the amounts payable shall, prior to actual payment, be subject to seizure or sequestration for the payment of any debts, judgments, alimony or separate maintenance owed by a Participant or any other person, nor shall such amounts be transferable by operation of law in the event of a Participant's or any other person's bankruptcy or insolvency.

11.5 Not a Contract of Employment

The terms and conditions of this Plan shall not be deemed to constitute a contract of employment between a Participating Employer and a Participant, and neither a Participant nor a Participant's Beneficiary shall have any rights against a Participating Employer except as may otherwise be specifically provided herein. Moreover, nothing in this Plan shall be deemed to give a Participant the right to be hired or retained in the service of a Participating Employer or to interfere with the right of a Participating Employer at any time to discipline or discharge a Participant who is an employee.

11.6 Protective Provisions

A Participant will cooperate with a Participating Employer by furnishing any and all information requested by a Participating Employer, in order to facilitate the payment of benefits hereunder, and by taking such physical examinations as a Participating Employer may deem necessary and taking such other action as may be requested by a Participating Employer.

11.7 Governing Law

The provisions of this Plan shall be construed and interpreted according to the laws of the State of Oregon, except as preempted by federal law.

11.8 Terms

In this Plan document, unless the context clearly indicates the contrary, the masculine gender will be deemed to include the female gender, and the singular shall include the plural.

11.9 Validity

In case any provisions of this Plan shall be held illegal or invalid for any reason, such illegality or invalidity shall not affect the remaining parts hereof, but this Plan shall be construed and enforced as if such illegal and invalid provision had never been inserted herein.

11.10 Notice

Any notice or filing required or permitted to be given to the Administrative Committee under the Plan shall be sufficient if in writing and hand delivered, or sent by registered or certified mail to the Administrative Committee or to the Secretary of Participating Employer. Notice to the Administrative Committee, if mailed, shall be addressed to the principal executive offices of Participating Employer. Notice mailed to the Participant shall be at such address as is given in the records of the Participating Employer. Notices shall be deemed given as of the date of delivery or, if delivery is made by mail, as of the date shown on the postmark on the receipt for registration or certification.

11.11 Successors

The provisions of this Plan shall bind and inure to the benefit of each Participating Employer and its successors and assigns. The term successors as used herein shall include any corporate or other business entity which shall, whether by merger, consolidation, purchase or otherwise, acquire all or substantially all of the business and assets of a Participating Employer, and successors of any such corporation or other business entity.

IN WITNESS WHEREOF, the Company has caused this instrument to be executed by its officers thereunto duly authorized this 4th day of March, 2005.

ADMINISTRATIVE COMMITTEE

PORTLAND GENERAL ELECTRIC COMPANY

2005 MANAGEMENT DEFERRED COMPENSATION PLAN

/s/ James F. Lobdell
James F. Lobdell
/s/ James J. Piro
James J. Piro
/s/ Arleen N. Barnett
Arleen N. Barnett

EXHIBIT 24.1

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that in connection with the filing by Portland General Electric Company ("Company") with the Securities and Exchange Commission of the Company's Annual Report on Form 10-K for the year ended December 31, 2004, the undersigned director of the Company hereby constitutes and appoints Douglas R. Nichols and Kirk M. Stevens, and each of them, with full power (any one of them acting alone), as true and lawful attorneys-in-fact and agents for and on behalf and in the name, place, and stead of the undersigned, in any and all capacities, to sign, execute, and file such Annual Report on Form 10-K, together with all amendments or supplements thereto, with all exhibits and any and all documents required to be filed with respect thereto, with the Securities and Exchange Commission and any regulatory authority, granting unto each above-named individual the full power and authority to do and perform each and every act and action requisite and necessary to be done in and about the pre mises in order to effectuate the same as fully to all intents and purposes as the undersigned might or could do if personally present, hereby ratifying and confirming all the acts said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

Effective as of March 10, 2005.

	/s/ Corbin A. McNeill, Jr.
	Corbin A. McNeill, Jr.

EXHIBIT 24.1

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that in connection with the filing by Portland General Electric Company ("Company") with the Securities and Exchange Commission of the Company's Annual Report on Form 10-K for the year ended December 31, 2004, the undersigned director of the Company hereby constitutes and appoints Douglas R. Nichols and Kirk M. Stevens, and each of them, with full power (any one of them acting alone), as true and lawful attorneys-in-fact and agents for and on behalf and in the name, place, and stead of the undersigned, in any and all capacities, to sign, execute, and file such Annual Report on Form 10-K, together with all amendments or supplements thereto, with all exhibits and any and all documents required to be filed with respect thereto, with the Securities and Exchange Commission and any regulatory authority, granting unto each above-named individual the full power and authority to do and perform each and every act and action requisite and necessary to be done in and about the pre mises in order to effectuate the same as fully to all intents and purposes as the undersigned might or could do if personally present, hereby ratifying and confirming all the acts said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

Effective as of March 10, 2005.

	/s/ Robert S. Bingham
	Robert S. Bingham

EXHIBIT 24.1

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KNOW ALL MEN BY THESE PRESENTS, that in connection with the filing by Portland General Electric Company ("Company") with the Securities and Exchange Commission of the Company's Annual Report on Form 10-K for the year ended December 31, 2004, the undersigned director of the Company hereby constitutes and appoints Douglas R. Nichols and Kirk M. Stevens, and each of them, with full power (any one of them acting alone), as true and lawful attorneys-in-fact and agents for and on behalf and in the name, place, and stead of the undersigned, in any and all capacities, to sign, execute, and file such Annual Report on Form 10-K, together with all amendments or supplements thereto, with all exhibits and any and all documents required to be filed with respect thereto, with the Securities and Exchange Commission and any regulatory authority, granting unto each above-named individual the full power and authority to do and perform each and every act and action requisite and necessary to be done in and about the pre mises in order to effectuate the same as fully to all intents and purposes as the undersigned might or could do if personally present, hereby ratifying and confirming all the acts said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

Effective as of March 10, 2005.

	/s/ Raymond S. Troubh
	Raymond S. Troubh

EXHIBIT 24.1

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that in connection with the filing by Portland General Electric Company ("Company") with the Securities and Exchange Commission of the Company's Annual Report on Form 10-K for the year ended December 31, 2004, the undersigned director of the Company hereby constitutes and appoints Douglas R. Nichols and Kirk M. Stevens, and each of them, with full power (any one of them acting alone), as true and lawful attorneys-in-fact and agents for and on behalf and in the name, place, and stead of the undersigned, in any and all capacities, to sign, execute, and file such Annual Report on Form 10-K, together with all amendments or supplements thereto, with all exhibits and any and all documents required to be filed with respect thereto, with the Securities and Exchange Commission and any regulatory authority, granting unto each above-named individual the full power and authority to do and perform each and every act and action requisite and necessary to be done in and about the pre mises in order to effectuate the same as fully to all intents and purposes as the undersigned might or could do if personally present, hereby ratifying and confirming all the acts said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

Effective as of March 10, 2005.

	/s/ Robert H. Walls, Jr.
	Robert H. Walls, Jr.

EXHIBIT 24.1

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that in connection with the filing by Portland General Electric Company ("Company") with the Securities and Exchange Commission of the Company's Annual Report on Form 10-K for the year ended December 31, 2004, the undersigned director of the Company hereby constitutes and appoints Douglas R. Nichols and Kirk M. Stevens, and each of them, with full power (any one of them acting alone), as true and lawful attorneys-in-fact and agents for and on behalf and in the name, place, and stead of the undersigned, in any and all capacities, to sign, execute, and file such Annual Report on Form 10-K, together with all amendments or supplements thereto, with all exhibits and any and all documents required to be filed with respect thereto, with the Securities and Exchange Commission and any regulatory authority, granting unto each above-named individual the full power and authority to do and perform each and every act and action requisite and necessary to be done in and about the pre mises in order to effectuate the same as fully to all intents and purposes as the undersigned might or could do if personally present, hereby ratifying and confirming all the acts said attorneys-in-fact and agents, or any of them, may lawfully do or cause to be done by virtue hereof.

Effective as of March 10, 2005.

	/s/ John W. Ballantine
	John W. Ballantine

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 11, 2005		/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 11, 2005		/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, 2004, 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 11, 2005		Date:	March 11, 2005