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, 2003
OR
[ ] **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the Transition period from ________________ to _______________

Commission File Number 1-5532-99

PORTLAND GENERAL ELECTRIC COMPANY

(Exact name of registrant as specified in its charter)

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

121 SW Salmon Street, Portland, Oregon 97204
(Address of principal executive offices) (zip code)

Registrant's telephone number, including area code: **(503) 464-8000**

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

Title of each class	Name of each exchange on which registered
Portland General Electric Company 8.25% Quarterly Income Debt Securities (Junior Subordinated Deferrable Interest Debentures, Series A)	New York Stock Exchange

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	None

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 29, 2004: 42,758,877 shares of common stock, $3.75 par value. (All shares are owned by Enron Corp.)

DEFINITIONS

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

Abbreviations or Acronyms	
AFDC	Allowance For Funds Used During Construction
Bankruptcy Court	United States Bankruptcy Court For The Southern District of New York
Beaver	Beaver Combustion Turbine Plant
Boardman	Boardman Coal Plant
BPA	Bonneville Power Administration
COBRA	Consolidated Omnibus Budget Reconciliation Act
Colstrip	Colstrip Units 3 and 4 Coal Plant
Coyote Springs	Coyote Springs Generation 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
Enron	Enron Corp., as Debtor and Debtor in Possession in Chapter 11, Case No. 01-16034 pending in the US 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	Financial Statements of Portland General 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
Tribes	Confederated Tribes of the Warm Springs Reservation of Oregon
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 51 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 2003 its service area population was approximately 1.5 million, comprising about 43% of the state's population. The Company added approximately 10,600 retail customers during 2003, and at December 31, 2003 served approximately 754,000 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.

On November 18, 2003, Enron and Oregon Electric Utility Company, LLC (Oregon Electric), a newly-formed Oregon limited liability company financially backed 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, and certain other regulatory agencies. For further information, see "Enron Bankruptcy" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operations".

As of December 31, 2003, PGE had 2,687 employees. This compares to 2,757 and 2,790 employees at December 31, 2002 and 2001, respectively. A total of 890 employees are represented by Local Union No. 125 (Local 125) of the International Brotherhood of Electrical Workers. Seventeen employees at Coyote Springs are covered under an agreement effective from September 1, 2001 through August 1, 2006. The Company and Local 125 have reached agreement on a new five-year agreement covering the other 873 employees. The new agreement is subject to approval by a vote of the covered employees.

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 2003, PGE served 246 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 20% of retail demand, they represent 9 different commercial and industrial groups, including paper manufacturing, high technology, metal fabrication, food merchandising, and health services. No single customer represents more than 3.9% of PGE's total retail load.

Total retail MWh energy sales decreased somewhat from 2002 due to a 10% decline in industrial sales, most of which was attributable to a single large customer which began generating its own power requirements in the second quarter of 2003. An increase in residential and commercial customers served in 2003 resulted in higher MWh energy sales, partially offsetting the decrease in industrial sales. Total retail revenue declined 10% from 2002 primarily as the result of a rate decrease (related to lower power costs) that became effective January 1, 2003 (see "Retail Rate Changes" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operations" for further information).

Wholesale (Non-Trading)

Non-trading wholesale electricity sales related to activities to serve retail load requirements comprised about 22% and 21% of total operating revenues in 2003 and 2002, respectively. Non-trading wholesale revenues and energy sales for the fourth quarter of 2003 were reduced by approximately $90 million and 2,116 thousand MWhs, respectively, to reflect the October 1, 2003 adoption of Emerging Issues Task Force No. 03-11 (EITF 03-11), Reporting Gains and Losses on Derivative Instruments That are Subject to FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, and Not Held for Trading Purposes. 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. Accordingly, such activities, formerly recorded on a "gross" basis in both Operating Revenues and Purchased Power and Fuel expense, are now recorded on a "net" basis in Purchased Power and Fuel expense. Prior period amounts have not been reclassified. See New Accounting Standards in Note 1, Summary of Significant Accounting Policies, in the Notes to Financial Statements.

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 daily 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, natural gas, and crude oil markets. Such activities are not reflected in the Company's retail rates. 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:

	2003		2002		2001	
	Amount	**%**	**Amount**	**%**	**Amount**	**%**
Operating Revenues (Millions)						
Residential	$ 555	43%	$ 567	41%	$ 475	42%
Commercial(*)	500	39%	550	40%	424	38%
Industrial	228	18%	269	19%	222	20%
Tariff Revenues	1,283	100%	1,386	100%	1,121	100%
Accrued (Collected) Revenues	45		82		(31)	
Retail	1,328		1,468		1,090	
Wholesale (Non-Trading)	393		391		1,313	
Other Operating Revenues:						
Trading Activities – net	2		(1)		(11)	
Other	29		(3)		28	
Total Operating Revenues	$1,752		$1,855		$2,420	
Megawatt-Hours Sold (Thousands)						
Residential	7,099	39%	7,058	38%	7,080	37%
Commercial(*)	7,190	39%	7,101	38%	7,285	38%
Industrial	4,137	22%	4,612	24%	4,675	25%
Retail	18,426	100%	18,771	100%	19,040	100%
Wholesale (Non-Trading)	9,966		12,645		9,764	
Trading Activities - net	-		-		15	
Total MWh Sold	28,392		31,416		28,819	

(*) Includes public street lighting

Note: Wholesale (Non-Trading) revenues and energy sales for 2003 have been reduced by $90 million and 2,116 thousand MWhs, respectively, reflecting the presentation required by EITF 03-11, which became effective on October 1, 2003. Prior period amounts have not been reclassified. For further information, see New Accounting Standards in Note 1, Summary of Significant Accounting Policies, in the Notes to Financial Statements.

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

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 rates 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, 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 approved the Trojan Decommissioning Plan. Approval of the Trojan Decommissioning Plan by the NRC and EFSC has allowed PGE to begin decommissioning activities. In 2001, the NRC approved PGE's License Termination Plan (LTP). The LTP 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 to house the nuclear fuel until permanent storage is available. Trojan is subject to NRC regulation until it is fully decommissioned, all nuclear fuel is removed from the site, decontamination is completed, and NRC licenses are terminated. 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 Operations" and Note 12, Trojan Nuclear Plant, in the Notes to Financial Statements.

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 the Public Utility Holding Company Act of 1935 (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) under Section 3(a)(1), in accordance with Rule 2 promulgated thereunder. Due to Enron's bankruptcy filing in December 2001, Enron is no longer able to provide necessary financial information needed to file under Rule 2. As a result, in February 2002, Enron filed an application seeking exemption under Section 3(a)(1). To be eligible for the Section 3(a)(1) exemption, it is necessary, among other things, that PGE's utility activities be predominantly intrastate in character.

The SEC issued an order on December 29, 2003, denying Enron's exemption application under Section 3(a)(1) of PUHCA, holding that PGE's utility activities were not predominantly and substantially intrastate in character. On December 31, 2003, Enron filed an application for an exemption as a public utility holding company under Section 3(a)(4) of PUHCA, based on the temporary nature of the applicants' interest in PGE under the Chapter 11 plan filed by Enron and certain of its subsidiaries. The hearing scheduled on the Section 3(a)(4) application was postponed to consider a settlement offer proposed by Enron. In accordance with the settlement offer, 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 (the "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. On the same day, Enron withdrew the Section 3(a)(4) application.

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.

However, 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.

PGE does not believe that becoming a subsidiary of a registered holding company will have a material adverse affect on its financial condition, results of operations, or cash flows. However, the finding in the SEC's December 29, 2003 order that PGE is not an intrastate utility could make it more difficult for any future owner of PGE to obtain a Section 3(a)(1) exemption from PUHCA.

Regulatory Matters

Electric Power Industry Restructuring

The electric power industry continues to experience change. The impetus for this change is public, regulatory, and governmental support for replacing the traditional cost-of-service regulatory framework with a market system under which customers have a choice of energy supplier. Federal laws and regulations now provide for open access to transmission systems. Several states, including Oregon, have adopted or are considering new regulations to allow direct access to retail energy suppliers.

State Regulations

Oregon's electricity restructuring law was implemented on March 1, 2002. It provides all commercial and industrial customers of investor-owned utilities direct access to competing Energy Service Suppliers (ESS) as well as cost-of-service and market price options. Residential and small commercial and industrial customers can purchase electricity from a "portfolio" of rate options that include a basic service rate, a time-of-use rate, and renewable resource rates. The law also requires that investor-owned utilities unbundle and separately identify the costs of electric service on a functional basis, including energy resources, delivery, and other services. It further provides for a "transition adjustment" for non-residential customers that choose to purchase energy at market rates from investor-owned utilities or from electricity service suppliers. 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.

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 (see "Energy Efficiency" in this section for further information). In addition, the law provides for low-income electric bill assistance.

Early results indicate a measured response to Oregon's electricity restructuring law. There are four ESS's registered to transact business with PGE in 2004, with two currently serving a total of seven customers (119 separate accounts) with an average load of approximately 86 MW. No customers were served by ESS's in 2003. A total of 66 commercial and industrial customers (approximately 100 separate accounts) received service from PGE under market-based pricing options in 2003. The Company has also offered an option under which certain large nonresidential customers may, for a minimum five-year term, elect to be removed from cost of service pricing, with energy supplied at a daily market rate or by an ESS; four customer accounts have chosen this option. Approximately 27,000 customers have chosen renewable energy options and approximately 1,600 customers have chosen the time of use option.

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 rates. Recovery of these costs has begun, with unrecovered costs totaling approximately $23 million at December 31, 2003. The OPUC staff conducted 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 be served 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 Regulations

The Energy Policy Act of 1992 (Energy Act) enabled changes in federal regulations to increase wholesale competition in the electric industry. The Energy Act eased restrictions on independent power production and granted authority to the FERC to mandate open access for the wholesale transmission of electricity.

The FERC has taken steps to provide a framework for increased competition in the electric industry. In 1996, the FERC issued Order 888 requiring non-discriminatory open access transmission by all public utilities that own interstate transmission. The final rule requires utilities to file tariffs that offer others the same transmission services they provide themselves under comparable terms and conditions. This rule also allows public utilities to recover stranded costs in accordance with the terms, conditions and procedures set forth in Order 888. The ruling requires reciprocity from municipals, cooperatives and federal power marketers receiving service under the tariff. The new rules became effective in July 1996 and have resulted in increased competition and more choices to wholesale energy customers. Other FERC policies allow qualifying entities to sell power at rates based on the market, rather than cost.

Restructuring of the electric industry has slowed at the federal level. Congressional committee hearings are expected to continue, although there remains considerable uncertainty regarding their ultimate outcome. PGE continues to formulate strategies to meet the challenges of wholesale competition.

Retail Rate Changes

Pursuant to PGE's 2001 general rate filing, the OPUC authorized retail price increases, effective October 1, 2001. The Commission also approved a power cost adjustment mechanism covering the period October 2001 through December 2002. As actual power costs during this period exceeded those costs used in rate determination, the power cost adjustment mechanism allowed the Company to defer for later recovery from retail customers actual net variable power costs in excess of certain baseline amounts. Pursuant to PGE's updated 2003 power cost forecast that estimated a reduction in power costs utilized in the Company's 2001 general rate filing, the OPUC authorized reductions in the Company's retail prices, effective January 1, 2003. PGE did not have a power cost adjustment mechanism in place for 2003.

For further information, see "Retail Rate Changes" and "Power Cost Adjustment Mechanisms" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operations".

Integrated Resource Plan

PGE filed an Integrated Resource Plan (IRP) with the OPUC in 2002, with a supplement filed in February 2003. The IRP describes the Company's strategy to meet the electric energy needs of its customers, with an emphasis on cost, long-term price stability, and supply reliability. It details resource actions over the next two to three years that provide for reduced reliance on short-term wholesale power contracts and increased emphasis on longer-term supplies. The IRP also addresses future investment in additional generating resources (including upgrades to existing resources), an increase in renewable resources, longer-term power purchases, the use of seasonal exchanges to meet peaking requirements, demand-side management, and capacity tolling contracts.

In June 2003, following approval by the OPUC, PGE 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 January 2004, PGE filed a Proposed Action Plan with the Commission on how to best meet its customers' future power supply requirements, beginning as early as 2006. PGE's recommendations to acquire 635 average MW in mid-term and long-term resources include three primary components: 1) construction of a natural gas-fired power plant at its Port Westward site in Columbia County, producing 240 or 350 average MW (depending on technology selected), beginning in late 2006; 2) acquisition of up to 65 average MW (195 MW capacity) of wind generation; and 3) acquisition of up to 300 average MW in gas tolling and fixed price power purchase agreements with durations of 5 to 10 years. In addition to the increased capacity resulting from these recommendations, the Proposed Action Plan includes approximately 485 MW of additional capacity from plant upgrades, extension of a current contract with the Tribes to 2012, standby generation, and peak tolling and seasonal exchange agreements.

Energy Efficiency

PGE has consistently promoted the efficient use of electricity. Prior to the March 1, 2002 enactment of Oregon's electricity restructuring law, PGE utilized Demand Side Management programs to provide a range of energy efficiency services to all customer classes. Since the restructuring law's enactment, PGE has promoted energy efficiency through information tips on its web site, newsletters to customers, and information provided by customer service representatives and account managers. PGE also refers customers to the Energy Trust of Oregon (see below) for conservation and energy efficiency services.

Beginning March 1, 2002, as provided by Oregon's electricity restructuring law, PGE began collecting a 3% Public Purpose Charge from retail customers to fund cost-effective conservation measures, renewable energy resources, school district conservation, and weatherization measures for low-income housing. Amounts collected are distributed monthly to organizations responsible for the administration of these programs. The Energy Trust of Oregon, a non-profit organization, administers the conservation and renewable resources portions of the public purpose funds, contracting with PGE and other companies to provide energy conservation and efficiency services to customers.

RTO West and Independent Transmission Company

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, alternatively, to file an explanation of reasons preventing them from making such filing. In response to this order, BPA and nine 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, Nevada, and small portions of California and Wyoming.

In July 2002, the FERC issued a Notice of Proposed Rulemaking (NOPR) on Standard Market Design (SMD) to standardize the structure and operation of competitive wholesale markets. If the NOPR is implemented as proposed, it will significantly change how wholesale energy and transmission markets operate. Wholesale companies and retail load serving companies would use a single network transmission tariff, and operational control of the transmission network would be administered by the RTO.

In September 2002, the formation plan of RTO West received preliminary approval of the FERC, with some modification and further development of certain details. In its approval ruling, the FERC stated that the RTO West proposal would satisfy Order No. 2000 requirements and provide a basic framework for an SMD for the West. Also in September 2002, the FERC granted preliminary approval of a proposed structure for TransConnect, a new company proposed by PGE and two other regional utilities, that would own or lease the high-voltage transmission facilities currently held by PGE and its other participants. As proposed, TransConnect would be an independent, jointly owned, for-profit transmission company that would participate in RTO West. Combining transmission resources into one independent entity could create new opportunities to attract capital for system improvements and expansion while improving transmission infrastructure and reducing regional transmission constraints.

In April 2003, the FERC outlined intended changes to its proposed rule on SMD. The proposed changes provide for a "phased-in" implementation schedule specific to each region and market power mitigation and monitoring requirements.

Decisions regarding the formation of RTO West and TransConnect will ultimately depend on the conditions imposed during the regulatory approval process, as well as economic considerations. Such decisions will be subject to approvals by state and federal agencies and individual company boards of directors.

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 the formation of a competitive electricity market in Oregon.

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 eligible customers regulated cost of service and market-based prices. 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 contributed 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. In addition, the Company will continue its trading activities to participate in electricity, natural gas, and crude oil markets. Although PGE has authority under its FERC tariff to charge market-based rates for wholesale energy sales, the Company is operating under a cost-based cap through December 18, 2004, under terms of a 2003 settlement agreement between PGE, the FERC, and other parties (for further information, see Item 3. - Legal Proceedings).

PGE's transmission system connects winter-peaking utilities in the Northwest and Canada, which have access to lower variable cost hydroelectric generation, with summer-peaking wholesale customers in California and the Southwest, which have higher variable cost fossil fuel generation. PGE uses this 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. Public ownership of PGE is currently being pursued by certain parties. For additional information, see "Public Ownership Initiatives" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operations".

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 firm purchases for periods of less than one year 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 2004. In addition, natural gas, used to fuel the Company's combustion turbine plants, is subject to price volatility. PGE continues to monitor its exposure to natural gas.

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

Generating Capability

PGE's existing hydroelectric, coal-fired, and gas-fired plants are important resources for the Company, providing 1,957 MW of generating capability (see Item 2. - "Properties" for a full listing of PGE's generating facilities). PGE's lowest-cost producers are its five FERC licensed hydroelectric projects incorporating 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 Bull Run hydroelectric project on the Sandy River.

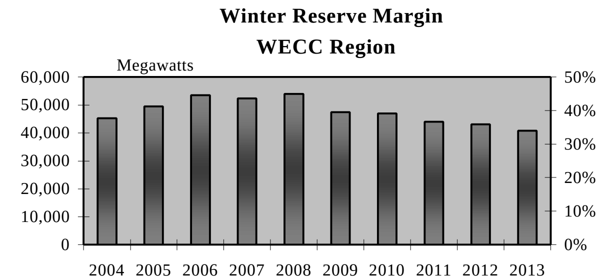
PGE's Proposed Action Plan, filed with the OPUC in January 2004 pursuant to the Integrated Resource Plan process, proposes construction of a new natural gas-fired power plant at the Company's Port Westward site in Columbia County, Oregon, adjacent to the existing Beaver plant site. PGE has obtained all necessary permits required to construct a two-unit combined cycle combustion turbine facility with up to 650 MW of production capacity. In consideration of other resource strategies outlined in its Proposed Action Plan, the Company has recommended construction of a single unit natural gas-fired power plant producing 240 or 350 average MW (depending on technology selected), with the unit placed in service in late 2006.

In 2001, PGE terminated its plans for a 49 MW combustion turbine facility located on leased property at Port of Morrow, Oregon, due to both reduced demand and lower power prices. The Company is currently marketing the gas turbine unit purchased for this facility.

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 740 MW of power from BPA, other Pacific Northwest utilities, and the Confederated Tribes of the Warm Springs Reservation of Oregon (Tribes). 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 with sufficient firm capacity to serve its peak loads. For further information, see "Power and Fuel Supply" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operations".

System Reliability and the WECC



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 is the largest and most diverse of the 10 regional electric reliability councils. It 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 156 members. The WECC area, which extends from Canada to Mexico and includes 14 western states, has great diversity in climate and 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 about 71 million people, will have sufficient capacity margin to meet forecast demand and energy requirements through the year 2013, assuming the timely completion of planned new generation.

PGE's peak load in 2003 was 3,351 MW, of which approximately 44% was met through short-term purchases. At December 31, 2003, PGE's total firm resource capacity, including short-term purchase agreements, was approximately 3,883 MW (net of short-term sales agreements of 3,910 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, and to potential civil or criminal liability for unauthorized "take" of listed species. Long-term recovery plans for these species may include major operational changes to the region's hydroelectric projects, including PGE's, with potentially significant impacts. 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 an ESA consultation on the Company's Pelton Round Butte Project (Deschutes River) and Willamette Falls Project (Willamette River), 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.

Completion of ESA consultation by the National Marine Fisheries Service, the FERC, and USFWS is required to obtain a FERC license or license amendment for hydroelectric projects, and provides authorization for take of listed species consistent with the terms and conditions identified through the consultation.

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 negotiates agreements each year to purchase coal for Boardman in the following calendar year, and currently has agreements that cover the plant's requirements through 2004. Available coal supplies are sufficient to meet future requirements of the plant. The coal, obtained from surface mining operations in Wyoming and Montana 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 2003, totaling about 2.6 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 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 Beaver at a 70% load factor. In addition, PGE has contractual access, through October 2004, 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 indicate 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 the plant in 2004.

Coyote Springs
The Coyote Springs generating station utilizes 41,000 Dth/day of firm transportation capacity on three interconnecting 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 the plant in 2004.

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, 2003.

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 December 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. Available information is currently not sufficient to determine either the total cost of investigation and remediation of the Portland Harbor or the potential liability of responsible companies, 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 Operations".

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

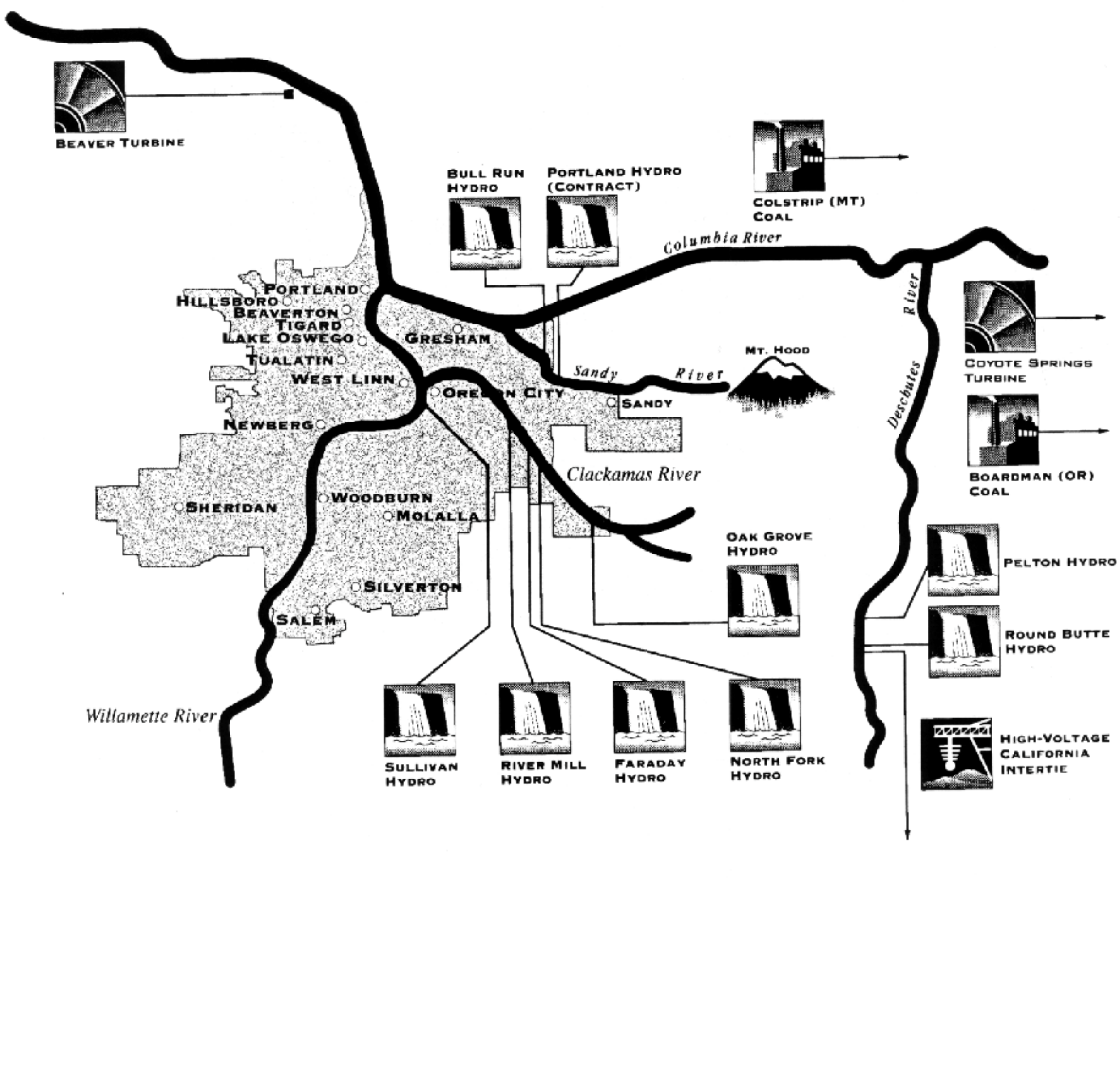
PGE's operations, principally its fossil-fuel electric generation plants, are subject to the federal Clean Air Act (Act) and other federal regulatory requirements. State governments also monitor and administer certain portions of the Act and must set guidelines that are at least equal to federal standards; Oregon's air quality standards exceed federal standards. Primary pollutants addressed by the Act 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 Act, along with expected future annual allowances, are sufficient to operate Boardman at a 60% to 67% capacity without emissions reductions. PGE has acquired additional emissions allowances to operate the Boardman plant at forecasted capacity through mid-2007 without the need to purchase additional emissions allowances. In addition, 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 plant operations, operating costs, or generating capacity.

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, 2003 (*)	PGE Interest
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	Boardman, OR	Coal	362	65.00%
Colstrip 3 & 4	Colstrip, MT	Coal	296	20.00%
Pelton	Deschutes River	Hydro	73	66.67%
Round Butte	Deschutes River	Hydro	225	66.67%
Total			1,957	

(*) PGE ownership share.

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 expires 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 by the end of 2004.

The license for the Clackamas River projects expires in 2006, and PGE will file a license application with the FERC in 2004.

The license for the Pelton Round Butte project expired at the end of 2001. In June 2001, PGE and the Tribes jointly filed a 50-year license application, which is pending with the FERC. The project has been operating on annual licenses since the license expired. Participants in the relicensing process will continue settlement discussions in 2004 to seek agreement on the terms and conditions of the new license.

It is anticipated that mandatory conditions, including facility modifications and operational changes, will be imposed on PGE's hydroelectric projects during the relicensing process to improve the passage, and enhance the survival, of adult and juvenile salmon.

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 the Marmot and Little Sandy Dams. 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 agreement provides for the removal of the Marmot Dam in 2007 and the Little Sandy Dam in 2008. PGE has requested that the existing license, which expires in November 2004, be extended to allow the project to operate until the removal of Little Sandy Dam. The FERC is expected to issue its amended license and surrender order in 2004. PGE's current rates include recovery of its remaining plant investment through the end of the project's existing license period 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

The rated generating capabilities of both Faraday and Round Butte were reduced by 2 MW based upon measurement testing completed during 2003. The generating capability at Beaver increased 16 MW due to improved efficiency resulting from evaporator re-tubing and replacement of economizer heat exchangers on the heat recovery steam generators.

Leased Properties

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

Item 3. Legal Proceedings

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

Following the closing of the Trojan Nuclear Plant, 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 reopened 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.

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). 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 March 24, 2003, PGE was served with two class action suits in Multnomah County Circuit Court, identical to the Marion County cases. On October 24, 2003, the Multnomah County suits were dismissed.

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

People of the State of California ex rel. Bill Lockyer, Attorney General v. Portland General Electric Company and Does 1 through 100. Superior Court of the State of California for County of San Francisco. Case No. CGC-02-408493/USDC Northern District of California, Case No. C-02-3318-VRW.

On May 30, 2002, the Attorney General of California filed a complaint alleging failure of PGE to comply with the Federal Power Act and with FERC requirements for its market based sales of power in California. On September 26, 2003, PGE and the California Attorney General agreed to settle this case. The agreement is part of a larger settlement (Settlement) with the Staff of the FERC and other parties related to trading activities by PGE during the California energy crisis in 2000-2001 in FERC Docket Nos. EL02-114-000 and EL02-115-000. The Settlement resolves this case and related non-public investigations, except that the California Attorney General is not precluded from pursuing any willfully fraudulent acts or omissions not known at the time of the settlement or any criminal acts or omissions.

Under the Settlement, PGE agreed to pay $8.5 million, of which $6.1 million was paid to California. PGE also agreed to file an amendment to its FERC market-based rates tariff that imposes a cost-based cap on prices charged for new wholesale electricity sales transactions for a prospective period of twelve months. In addition, PGE agreed to conduct annual training for its trading floor employees on code of conduct, standards of conduct, antitrust and ethics, and to retain for five years recordings of affiliate trading transactions, affiliate postings and related accounting records. The Settlement provides that it will not be deemed an admission of fault or liability by PGE for any reason and implies no admission or fault by PGE.

On December 17, 2003, the FERC approved the Settlement, which was uncontested. There is no further appeal.

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 fees. 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.

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.

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.

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.

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

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

On May 28, 2003, PGE filed a motion for summary judgment. On August 14, 2003, the Court granted PGE's motion for summary judgment. 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 and Related Stockholder Matters

PGE is a wholly owned subsidiary of Enron, which owns all 42,758,877 shares of PGE's outstanding common stock. No cash dividends were declared on common stock in 2003 or 2002. PGE declared a non-cash dividend of $27 million in July 2002. For further information, see Note 13, Related Party Transactions, in the Notes to Financial Statements.

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, terms of PGE's revolving credit facility prohibit the payment of any cash dividends or any other distribution by PGE on its common stock.

Item 6. Selected Financial Data

	For the Years Ended December 31				
	2003	2002	2001	2000	1999
			(In Millions)		
Operating Revenues (a)	$1,752	$1,855	$2,420	$1,887	$1,378
Net Operating Income	124	135	134	206	190
Net Income	58	66	34	141	128
Total Assets (b)	3,372	3,455	3,622	3,566	3,261
Long-Term Debt (c)	983	1,046	972	880	763

(a) Operating Revenues for 2003 reflects the October 1, 2003 adoption of EITF 03-11, Reporting Gains and Losses on Derivative Instruments That are Subject to FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, and Not Held for Trading Purposes. 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 have not been reclassified. Accordingly, Operating Revenues for these periods are not fully comparable to 2003 and do not reflect PGE's current reporting. For further information, see New Accounting Standards in Note 1, Summary of Significant Accounting Policies, in the Notes to Financial Statements.

(b) Amounts for 1999 through 2002 have been 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. For further information, see Note 11, Asset Retirement Obligations, in the Notes to Financial Statements.

(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 Operations

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 prices are regulated by the FERC.

Although Oregon's recent 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 under rates determined by the cost of service. Subject to regulatory review and timing, PGE expects the OPUC to recognize all prudently-incurred costs in setting rates, although there can be no assurance that the Company will have an opportunity to fully recover its costs through rates set in the regulatory process. While customer rates applicable to projected power costs are adjusted on an annual basis, rates applicable to non-power costs are adjusted only in a general rate proceeding. As electricity rates are fixed during the year, fluctuations in both energy sales and power and fuel prices can significantly impact the Company's earnings.

Enron Bankruptcy - Uncertainties associated with potential liabilities and risks resulting from Enron's bankruptcy are diminishing as Enron progresses through its bankruptcy process. Enron has agreed to sell PGE to Oregon Electric Utility Company, LLC (Oregon Electric) and the process of securing approvals for the sale has begun, with a decision expected by year-end 2004. However, if PGE is not sold, under Enron's plan of reorganization, PGE's stock will be distributed to Enron's creditors and it will become an independent company. Whether PGE is sold or its stock is distributed, control of employee benefit and retirement savings plans will be returned to PGE by the end of 2004.

Economy - Typical of electric utilities, PGE's business is affected by the general economy and by population growth in its service territory. The Company continues to experience customer growth, adding approximately 35,000 retail customers in the first four years of this decade (2000-2003), and now serves over 754,000 customers as the largest supplier of electricity in the state. The Company's diverse retail customer base has helped mitigate the effects of a downturn in Oregon's economy, notably impacting the high tech industry and other manufacturing sectors, where sales dropped sharply in 2002 and remained depressed in 2003. Oregon is slowly recovering from the recession, with seasonally-adjusted unemployment falling from a high of 8.5% in June 2003 to 7.2% in December 2003.

Retail energy sales during the last half of 2003 reflect the economic improvement, with gains in the residential and commercial markets offsetting a continued slow manufacturing sector. A key driver of sales growth in the residential and commercial markets remains population growth. An improving job market in the service sector and a softening of mortgage interest rates have sustained the local housing market. The Company plays an active role in supporting growth in its service territory, engaging in regional economic development strategies that promote job creation and load growth, and encouraging retention and expansion actions of its major industrial customers.

Operations - Despite a challenging economic environment, PGE continues to operate well and is financially sound. PGE's earnings in 2003 were not reflective of the Company's historical operations and cash flows. As in 2001 and 2002, financial reserves and a decline in retail energy sales resulting from the slow economy contributed significantly to a decline from normal earnings levels. The 2000-2001 West Coast energy crisis, centered largely on the supply of electricity and significantly affected by events in California's deregulated power markets, continued to have an effect on the Company, with 2003 reserves related primarily to investigations into wholesale power market activities during 2000 and 2001. In addition, adverse hydro conditions, the lack of a power cost adjustment mechanism, and the disallowance of certain power purchase contracts in customer rates had a negative impact on 2003 earnings. The OPUC has denied PGE's application to defer energy costs incurred to offset adverse hydro conditions in 2003.

The Company continues to meet regulatory standards for safety and service quality related to outage frequency and duration. The Company's customer satisfaction index has remained strong over the past several years among both residential and business customers, with reliability, restoration response, and customer service significant factors. PGE continues to invest in its transmission, distribution, and customer service systems and in upgrades to its generating plants. Decommissioning of the Company's closed Trojan nuclear plant is proceeding well, with transfer of spent fuel to a temporary storage facility completed ahead of schedule in 2003 and license termination anticipated in 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 2003 rejected a PUD initiative in Multnomah County, where a majority of PGE's customers reside. On March 9, 2004, Yamhill County voters also rejected a PUD initiative. The Company faces another PUD initiative in Clackamas County on May 18, 2004.

Financial Condition - Although PGE's earnings have been below expectations due to both a slow economy and financial reserves related to wholesale market activities, the Company has maintained a strong financial position and stable cash flow. As a financially sound utility, PGE has succeeded in securing financing, enabling it to effectively invest in its systems, serve customers, and improve operational efficiency.

The Company maintains investment-grade ratings on its secured debt with all the major credit rating agencies and successfully issued new debt and refinanced high coupon debt in 2002 and 2003. PGE maintains adequate liquidity through its revolving credit facility, cash from operations, and access to short-term debt markets, and continues to meet all financial covenants and requirements of its debt and financing agreements. The Company expects to meet the majority of its operating and capital requirements in the next few years with cash from operations and short-term borrowings. Long-term financing of $75 million to $100 million is anticipated in both 2004 and 2005.

Both regulatory "ring fencing" provisions and the establishment of a bankruptcy remote structure have effectively insulated PGE and its customers from adverse affects of Enron's bankruptcy. PGE has not paid a cash dividend since the second quarter of 2001, increasing the Company's equity position and strengthening its balance sheet. The added protection helps secure financing and positions the Company for investment in any new power supply resources.

Power Supply - PGE manages its power supply to secure reasonably priced power for customers by effectively using the Company's assets and position in the marketplace. PGE can meet approximately 75% of its estimated 2004 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. The

Company remains active in wholesale energy markets, which are integral to PGE's retail business, providing for the efficient use of its generating capacity. Wholesale energy market prices in the western states were relatively stable during the last year compared to 2002 and 2001. The Company took several actions to maintain a balanced net energy position through the winter peak period and the remainder of the year through a combination of existing physical resources, electricity purchases, and peaking generation facilities.

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.

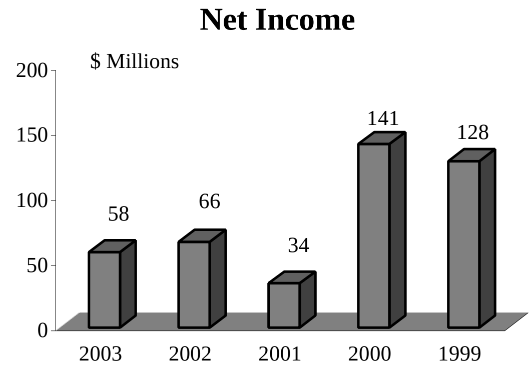
Below average water conditions in 2003 reduced generation from PGE's hydroelectric projects by 35,000 MWh from 2002. Although hydro conditions in both the Clackamas and Deschutes river systems, where the Company's facilities are located, are projected at somewhat above normal in 2004, it is anticipated that regional water conditions will continue at below normal levels during 2004. 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 negatively affect generation and purchased power costs.

Recent regulatory activities include the implementation of a "Resource Valuation Mechanism" (RVM) process that provides for customer rate adjustments based upon changes in projected power costs. This process resulted in a rate decrease for 2003 and a small average increase for 2004. In addition, power cost adjustment mechanisms have allowed the deferral and subsequent recovery of increases in net variable power costs that exceed established baseline amounts. The Company continues to recover power costs deferred under those mechanisms in effect during 2001 and 2002. As the cost of power, driven by variability in hydro conditions, remains a major risk to PGE, the Company will continue to work with Oregon's commission to develop a multi-year power cost adjustment mechanism focused on variations in hydro conditions.

PGE also continues to work with the Oregon commission in developing and implementing an Integrated Resource Plan that addresses resource actions required to meet the future electricity needs of its customers, with an emphasis on both price stability and flexibility. Regulatory acknowledgement of the plan would support Company actions in rate decisions related to future resource acquisitions.

Results of Operations

2003 Compared to 2002



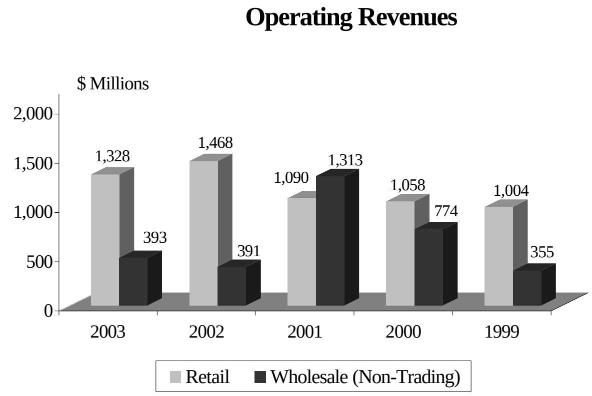
PGE's net income in 2003 was $58 million compared to $66 million in 2002. Results for 2003 included after tax provisions totaling approximately $19 million related to investigations into wholesale power market activities during 2000 and 2001, consisting of $14 million related to amounts due the Company 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 is improving, retail energy 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:

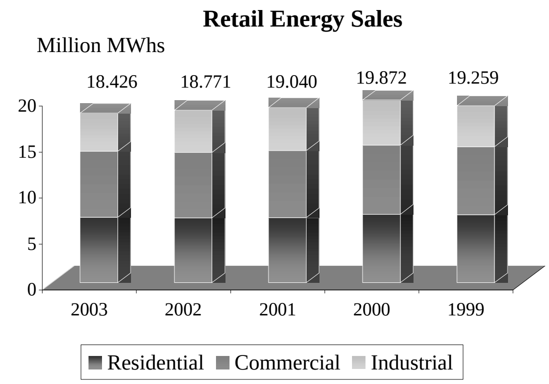
Operating Revenues	2003	2002	Increase/(Decrease)	
(In Millions)			Amount	%
Retail	$1,328	$1,468	$ (140)	(10%)
Wholesale (Non-Trading)	393	391	2	1%
Other Operating Revenues:				
Trading activities - net	2	(1)	3	*
Other	29	(3)	32	*
Total Operating Revenues	$1,752	$1,855	$ (103)	(6%)
Energy Sales				
(In Thousands of MWhs)				
Retail	18,426	18,771	(345)	(2%)
Wholesale (Non-Trading)	9,966	12,645	(2,679)	(21%)
Trading Activities	13,551	11,292	2,259	20%
Total Energy Sales	41,943	42,708	(765)	(2%)

(*not meaningful)

Note: Wholesale (Non-Trading) revenues and energy sales for 2003 have been reduced by $90 million and 2,116 thousand MWhs, respectively, reflecting the presentation required by EITF 03-11, which became effective on October 1, 2003. Prior period amounts have not been reclassified. For further information, see New Accounting Standards in Note 1, Summary of Significant Accounting Policies, in the Notes to Financial Statements.



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 rates by an average of approximately 7% on January 1, 2003 to reflect a decrease in projected 2003 variable power costs (see "Retail Rate Changes" 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 last year, 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 generation. 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 (for further information, see "Power Supply" in the Financial and Operating Outlook section). 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 2002, 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 the Financial and Operating Outlook section). 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, due to last year's planned maintenance and economic displacement of combustion turbine generation, and planned maintenance and repair outages at the Company's coal-fired generating plants.

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 on March 2, 2004.

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 credits to purchased power and fuel costs related to PGE's power cost adjustment mechanisms, as discussed above.

Megawatt-Hours/Variable Power Costs

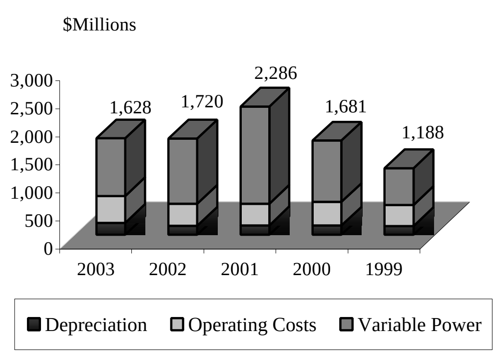
	Megawatt-Hours (thousands)		Average Variable Power Cost (Mills/KWh)	
	2003	2002	2003	2002
Generation	7,922	7,625	15.6	17.1
Term Purchases	19,365	21,311	35.0	42.5
Spot Purchases	2,404	3,619	38.5	20.0
Total Send-Out	29,691	32,555	32.2*	35.9*

(* 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 October 1, 2003. For further information, see New Accounting Standards in 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).

Operating Expenses



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 tax expense) 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.

2002 Compared to 2001

PGE's net income in 2002 was $66 million compared to $34 million in 2001. Results for 2001 included a $48 million after tax provision for uncollectible accounts receivable from Enron and affiliated companies due to uncertainties surrounding Enron's bankruptcy proceedings. In addition, 2001 results included an $11 million gain from a cumulative effect of a change in accounting principle resulting from the adoption of SFAS No. 133 where certain non-trading derivatives were recorded at fair value. Earnings in 2002 were unfavorably impacted by a 1.4% decline in retail energy sales from 2001, resulting from the combined effects of Oregon's poor economy and conservation efforts. In addition, retail energy sales in 2002 were approximately 8% lower than levels used in the Company's general rate case implemented in the fourth quarter of 2001. A power cost adjustment mechanism in place during 2002, in which $41 million was deferred for future collection from customers, partially offset the negative earnings impact of lower energy sales. Settlement of issues associated with 2003 estimated power costs also resulted in the Company recording a $4.6 million pre-tax charge to 2002 earnings by reducing amounts recoverable under the power cost adjustment mechanism. The impact of lower retail energy sales in 2002 was partially offset by reduced losses on energy trading activities and the effect of non-recurring provisions recorded in 2001 related to amounts owed the Company for certain prior year wholesale electricity sales made in California.

The following table summarizes Operating Revenues and Energy Sales for 2002 and 2001:

Operating Revenues (In Millions)	2002	2001	Increase/(Decrease) Amount	Increase/(Decrease) %
Retail	$1,468	$1,090	$ 378	35%
Wholesale (Non-Trading)	391	1,313	(922)	(70%)
Other Operating Revenues:				
Trading activities - net	(1)	(11)	10	*
Other	(3)	28	(31)	*
Total Operating Revenues	$1,855	$2,420	$(565)	(23%)
Energy Sales (In Thousands of MWhs)				
Retail	18,771	19,040	(269)	(1%)
Wholesale (Non-Trading)	12,645	9,764	2,881	30%
Trading Activities	11,292	3,862	7,430	*
Total Energy Sales	42,708	32,666	10,042	31%

(*not meaningful)

The decrease in total Operating Revenues in 2002 was due to significantly lower wholesale prices for sales of energy in excess of retail customer requirements. The decrease in Wholesale (Non-Trading) revenues is attributable to a 77% average price decrease from 2001 due to market forces within the region, including the effects of improved hydro conditions, lower natural gas prices, conservation, and a reduction in demand due to a slowing economy. Wholesale (Non-Trading) sales volume increased 30% as energy marketing activity returned from lower levels in 2001 caused by price volatility and uncertainty related to the cost and availability of power in western markets. In addition, power in excess of retail requirements, from forward contracts entered into in 2000 and 2001, was sold in the wholesale market in 2002; in 2001, power from such contracts was used to replace low hydro generation to meet retail load. The increase in retail revenues was due primarily to a general rate increase that became effective October 1, 2001; energy sales decreased 1.4% as a slow economy more than offset an approximate 7,700 (1.0%) increase in total customers from the end of 2001. (See "Retail Growth and Energy Sales" in the Financial and Operating Outlook section for further information). Included in the increase in retail revenues is the effect of the recognition in 2002 of $42 million in revenues deferred in 2001 related to differences between the timing of such revenues and related variable power costs over the 15-month period ending December 31, 2002.

Other Operating Revenues decreased $21 million due largely to lower prices on sales of natural gas in excess of generating requirements, as power purchases economically displaced higher cost gas-fired thermal generation. This was partially offset by the effect of lower losses on the Company's energy trading activities in 2002, as the Company's cost of power and fuel sold in the wholesale market significantly exceeded wholesale market prices in 2001.

Purchased Power and Fuel costs decreased $577 million (33%) due to lower prices for power purchases, lower fuel costs, and reduced thermal generation. Due to lower regional power and natural gas prices, the average cost of firm power purchases was approximately half that of 2001. Combined with lower prices for spot market purchases and a 43% decrease in thermal generation, PGE's average variable power cost for 2002 was 60% of 2001 (for further information, see "Power Supply" in the Financial and Operating Outlook section). Purchased Power and Fuel costs in 2002 and 2001 include credits of $36 million and $84 million, respectively, under the two separate power cost adjustment mechanisms in effect during the two years. Although PGE was able to defer substantial power costs in 2001 for future recovery from customers, it was necessary for the Company to absorb approximately $54 million in costs exceeding the power cost baseline established by the OPUC under the mechanism then in effect. In 2002, it was necessary for the Company to absorb $42 million under the mechanism in effect during the year, the majority of which was attributable to lower retail loads. (See "Power Cost Adjustment Mechanisms" in the Financial and Operating Outlook section for further information).

Energy generation from PGE's plants decreased 38% from 2001 due to planned maintenance and economic displacement of combustion turbine generation, and planned maintenance and forced repair outages at the Company's coal fired generating plants. Hydro energy production decreased 13%, with the loss in generation attributable to the January 1, 2002 sale of a 33.33% interest in the Company's Pelton Round Butte project partially offset by improved stream flows during the year. Total generation met approximately 38% of PGE's retail load during the year, compared to 61% in 2001.

The following table indicates PGE's total system load (including both retail and wholesale but excluding energy trading contracts) for 2002 and 2001. 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)	
	2002	2001	2002	2001
Generation	7,625	12,331	17.1	18.9
Term Purchases	21,311	16,098	42.5	83.4
Spot Purchases	3,619	1,626	20.0	112.2
Total Send-Out	32,555	30,055	35.9*	60.0*

(* includes wheeling costs)

Operating Expenses (excluding Purchased Power and Fuel, Depreciation and Amortization, and taxes) decreased $14 million (5%). Production and Distribution expenses decreased $10 million due to the termination of flowage easement fees to the Tribes related to the operation of PGE's Pelton Round Butte hydroelectric project, a 33.33% interest in which was sold to the Tribes in January 2002. Reduced maintenance costs at the Company's thermal generating plants were offset by higher delivery system costs, including tree trimming and other distribution-related work. Administrative and other expenses decreased due to reduced energy efficiency expenditures, including the discontinuance of the Compact Fluorescent Lighting program; this was partially offset by increased provisions for uncollectible customer accounts, costs related to the implementation of a new customer information and billing system, and employee severance expenses.

Depreciation and Amortization expense decreased $9 million (5%). A $30 million decrease due to regulatory amortization, including the amortization of regulatory liabilities related to various refunds to customers, was partially offset by a $21 million increase in depreciation of utility plant, due to both normal property additions and to higher depreciation rates established in the Company's 2001 general rate case implemented October 1, 2001.

Income taxes increased $30 million primarily due to higher taxable income. Year 2002 also included 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. In 2001, there were certain nonrecurring credit adjustments totaling $5 million recorded related to prior years' amended tax returns and deferred tax and audit adjustments.

Other Income increased $67 million primarily due to the effect of a $79 million provision for uncollectible accounts receivable from Enron and affiliated companies recorded in December 2001 to reflect uncertainties surrounding Enron's bankruptcy proceedings. In 2002, PGE reserved an additional $7 million for interest accrued during the year on the Merger Receivable from Enron and $2 million for receivable amounts due from Portland General Holdings, Inc. (PGH) and its subsidiaries. The Company also reversed a $3 million credit reserve established in 2001 related to receivables from Enron. The write-off of certain non-utility investments in 2002 was partially offset by higher interest income on regulatory assets, including interest on the unrecovered balance of the Company's power cost adjustment mechanism. Reserves of $3 million and $5 million were recorded in 2002 and 2001, respectively, related to the cancellation of a proposed gas turbine generation project. Losses of $5 million were incurred in both 2002 and 2001 on investments in trust owned life insurance policies as a result of the downturn in the financial markets. The increase in Other Income resulted in a $26 million reduction in tax benefits from 2001.

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 provided by 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 weather conditions. Temperatures outside the normal range during the year can result in increased or decreased electricity usage, causing an increase or decrease in operating cash flows, and a resulting impact on the need for short-term borrowings to meet current cash requirements.

PGE generated cash from operations in amounts considerably greater than net income in each of the last three years (excluding the effect of net margin deposit activity in 2001). An increase in 2001 margin deposit requirements on energy trading activities, related to changes in power and natural gas prices, reduced cash flow by $223 million.

Cash provided by operating activities totaled $307 million in 2003 compared to $305 million in 2002. Increased cash receipts resulted from an increase in wholesale energy sales and prices and recovery from retail customers of amounts related to power cost adjustment mechanisms in effect during 2001 and 2002. Such increases were largely offset by decreased refunds of margin deposits from wholesale customers, related to the settlement of certain energy contracts, and by a decrease in cash received from retail electricity sales, due to lower energy sales and a January 1, 2003 rate decrease.

Cash from operations and remaining proceeds from the issuance of long-term debt (described below) were invested primarily in government money market funds at December 31, 2003. 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 maturing within one year, as approved by PGE's board of directors.

Investing Activities consist primarily of improvements to PGE's distribution, transmission, and generation facilities. Capital expenditures of $167 million in 2003 approximated those of 2002. The $30 million change in "Other - net" includes the effect of the termination of a 1996 power sale termination agreement, under which the Company received $28 million in 2002. For additional information regarding future investing activities, see "Cash Requirements" in this section.

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

During 2003, PGE issued $200 million in First Mortgage Bonds at interest rates ranging from 5.279% to 6.875%. These Bonds were issued as private placements, maturing from 2013 through 2033. Net proceeds from these issues and cash provided from operations were used to redeem $180 million of First Mortgage Bonds, bearing interest rates ranging from 6.47% to 9.46%, and $70 million of 8.25% Junior Subordinated Deferrable Interest Debentures. Bonds issued in 2003 provided funds for debt maturing during the year and reduced PGE's borrowing costs by replacing higher rate debt.

PGE also repurchased $142 million in Pollution Control Bonds that were subsequently remarketed for a term of six years at fixed rates of 5.20% (for $121 million of the bonds) and 5.45% (for $21 million). The bonds are secured by First Mortgage Bonds issued by the Company. The Pollution Control Bonds were required to be repurchased during 2003 and were remarketed to take advantage of cost savings associated with secured, tax-exempt debt.

In addition, the Company repaid $9 million of conservation bonds, retired $3 million of preferred stock, and paid $2 million in preferred stock dividends. As required by SFAS No. 150, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity, $1 million of dividends paid after June 30, 2003 are classified as interest expense on the income statement. No cash dividends on common stock were declared or paid in 2002 or 2003.

In May 2003, PGE completed a new $150 million 364-day revolving credit facility with a group of commercial banks that replaced two separate facilities that were terminated upon execution of the new agreement. Under the new credit facility, PGE has the option to issue up to $100 million of the $150 million credit line in letters of credit. The letter of credit provisions of the revolving credit facility accommodate PGE's collateral requirements related to its wholesale trading activities and other operating needs. At December 31, 2003, the Company had utilized approximately $18 million in letters of credit. The facility contains a material adverse change clause and financial covenants that limit consolidated indebtedness, as defined in the facility, to 60% of total capitalization; it also requires that PGE maintain an interest coverage ratio, as defined in the facility, of not less than 3.75:1. At December 31, 2003, the Company's indebtedness to total capitalization and interest coverage ratios, as calculated under the facility, were 47.1% and 4.85:1, respectively. The new facility is secured by First Mortgage Bonds issued by the Company and requires annual facility fees of 0.25%. The new facility prohibits the payment of any cash dividends or any other distributions by PGE on its common stock.

In 2003, existing cash and short-term investments, along with cash provided by operations, replaced the use of commercial paper in meeting the Company's day-to-day requirements.

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 securing the bonds. As of December 31, 2003, 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 facility supplements operating cash flow and provides a primary source of liquidity. PGE's ability to secure sufficient long-term capital at reasonable cost is determined by its financial performance and outlook, capital expenditure requirements (including the effects of these factors on the Company's credit ratings), and alternatives available to investors. The Company's ability to obtain and renew such financing depends on its credit ratings as well as on bank credit markets, both generally and for electric utilities in particular.

PGE's financial policies have been established by the Company's management and approved by its board of directors. Such policies include the balancing of debt and equity to maintain a low weighted average cost of capital while retaining sufficient flexibility to meet the Company's financial obligations. PGE's objective is to maintain a common equity ratio (common equity to total consolidated capitalization, including current debt maturities) of 50% to 55%. 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 54.5% and 51.9% at December 31, 2003 and 2002, respectively.

As previously indicated, a significant portion of cash provided by operations consists of depreciation and amortization of utility plant which are recovered in rates but require no current cash outlay. PGE estimates recovery of such charges to approximate $160 million to $190 million annually over the period 2004-2006. Combined with all other sources, total cash provided by operations is estimated to range from $300 million to $360 million during the 2004-2006 period.

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

	2004	2005	2006
Capital expenditures (a)	$180 - $200	$165 - $185	$180 - $200
Long-term debt maturities	$56	$30	$11

(a) System improvements to support both new and existing customers, excluding the proposed construction of Port Westward.

Projected cash flow from operations in excess of cash requirements may be used to fund costs associated with securing new energy resources, including the proposed construction of the Port Westward combustion turbine plant. Construction of Port Westward is contingent upon OPUC review and acknowledgment of PGE's Integrated Resource Plan (for further information, see "Integrated Resource Plan" in Part I, Item 1. Business - Regulatory Matters). Under the Company's proposal, it is anticipated that the Port Westward plant would be operational in late 2006 and cost approximately $210 million to $260 million, excluding Allowance for Funds Used During Construction, ($80 million to $100 million in 2004, $110 million to $130 million in 2005, and $20 million to $30 million in 2006). To the extent necessary, long-term debt may be considered to fund any potential shortfall. Additional liquidity is available under the Company's revolving credit facility, which is expected to be replaced with a similar facility upon its May 27, 2004 expiration date. PGE anticipates long-term financing activity of $75 million to $100 million in both 2004 and 2005.

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

In March 2004, S&P placed PGE's credit ratings on CreditWatch with negative implications following Oregon Electric's filing with the OPUC to purchase PGE from Enron. S&P's Outlook change is based on their view of the consolidated leverage from the proposed acquisition of PGE by Oregon Electric. Should Moody's and S&P 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, 2004, PGE had posted, in the form of letters of credit, approximately $7 million of collateral. 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, 2004, the approximate amount of additional collateral that could be requested upon such a downgrade event is $30 million and decreases to approximately $23 million by year-end 2004. In addition to collateral calls, such a credit rating reduction could impact the terms and conditions of long-term debt issued in the future. Any rating reductions could also increase interest rates and fees on PGE's revolving credit facility, increasing the cost of funding the Company's day-to-day working capital requirements.

Due to the Company's increased liquidity and financial flexibility, PGE has regained its ability to access the commercial paper market, to which it had temporarily lost access due to ratings reductions for commercial paper by Moody's and Fitch in May 2002. As discussed in "Cash Requirements" above, management believes that the Company's existing line of credit 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 the 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, 2003 (in millions):

	Payments Due						
	Total	**2004**	**2005**	**2006**	**2007**	**2008**	**After 2008**
Long-Term Debt	$ 983	$ 56	$ 30	$ 11	$ 70	$ -	$ 816
Operating Leases	193	10	9	6	7	7	154
Purchase Commitments	33	33	-	-	-	-	-
Purchased Power and Fuel:							
Electricity Purchases	848	577	121	117	5	5	23
Capacity Contracts	252	19	19	19	19	19	157
Natural Gas Agreements	159	48	16	16	14	14	51
Public Utility Districts	76	7	7	6	6	6	44
Coal and Transportation Agreements	48	12	4	4	4	4	20
Trojan:							
Decontamination and Decommissioning Fund	3	1	1	1	-	-	-
Decommissioning Funding Assurance (*)	15	12	3	-	-	-	-
Total Contractual Cash Obligations	$2,610	$ 775	$ 210	$ 180	$ 125	$ 55	$1,265

(*) Indicated amounts represent highest amount of required collateral during year. See Note 12, Trojan Nuclear Plant, in the Notes to Financial Statements for further information.

Other Financial Obligations and Guarantees

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.

PGE entered into a sale transaction in 1985 in which it sold an undivided 15% interest in its Boardman coal plant (Plant) and a 10.714% undivided interest in the Pacific Northwest Intertie (Intertie) transmission line (jointly the Boardman Assets) to an unrelated third party (Purchaser). The Purchaser leased the Boardman Assets to a lessee (Lessee) unrelated to PGE or the Purchaser. Concurrently, PGE assigned to the Lessee certain agreements for the sale of power and transmission services from the Plant and the Intertie (P&T Agreements) to a regulated electric utility (Utility) unrelated to PGE, the Purchaser, or the Lessee. The payments by the Utility under the P&T Agreements exceed the payments to be made by the Lessee to the Purchaser under the lease. In exchange for PGE undertaking certain obligations of the Lessee under the lease, the Lessee reassigned to PGE certain rights, including the excess payments, under the P&T Agreements. However, in the event that the Utility defaults on the payments it owes under the P&T Agreements, PGE may be required to pay the damages owed by the Lessee to the lessor under the lease. Assuming no recovery from the Utility and no reduction in damages from mitigating sales or leases related to the Boardman Assets and P&T Agreements, the maximum amount that would be owed by PGE for the year 2004, is approximately $237 million. Management believes that circumstances that could result in such amount, or any lesser amount, being owed by the Company are remote.

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. As recoveries or refunds are reflected in future rates, the applicable regulatory asset or regulatory liability balances 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 $387 million and $257 million, respectively, at December 31, 2003.

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

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 Amortization expense, with those related to Other property included in Other Income (Deductions). In accordance with requirements of SFAS No. 143, accumulated asset retirement removal costs that do not qualify as AROs have been reclassified from Accumulated depreciation to Regulatory liabilities on the Balance Sheet.

Trojan Decommissioning

In early 1993, PGE ceased commercial operation of Trojan and began the decommissioning process. The original Trojan decommissioning cost estimate was prepared by an engineering firm with subsequent updates by PGE, due primarily to the effects of inflation and the timing of certain activities. The net estimated liability for Trojan decommissioning costs as of December 31, 2003 was $104 million, measured at estimated fair value. PGE collects $14 million annually from customers through 2011, which amount is based on the decommissioning cost estimate. Amounts collected from customers are deposited in an external trust fund, which reimburses PGE for costs expended under the decommissioning plan. The decommissioning estimate includes amounts for equipment removal, embedded pipe remediation, surface decontamination, non-radiological decontamination, and on-site spent nuclear fuel storage (until permanent storage is provided by the USDOE). Estimating the cost of decommissioning activities over a period extending to 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.

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, 2003, PGE has net accounts receivable balances totaling approximately $61 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.

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 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.

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, natural gas forward, swap, option and futures contracts, and crude oil 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 endeavor to minimize net power costs for retail customers. PGE enters into derivative contracts for trading purposes to participate in electricity, natural gas, and crude oil markets; such activities are not reflected in PGE's retail rates. 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 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.

Mark-to-Market
Marking a contract to market consists of reevaluating the market value over the entire term of the contract at the end of each reporting period and recording the resulting gain or loss of value in 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 indications received from electronic and telephone brokers, industry publications, NYMEX, and other sources, and are validated using independent publications. 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 4%.

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.

These estimates change with market conditions. Unpredictable factors such as weather and the economy may materially affect the forward price curves. Each forward price curve is derived by various market factors.

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, 2003, the plan's assets were comprised of approximately 71% equities and 29% other assets.

Assumption changes may materially affect net periodic pension income. Reducing the expected long-term rate of return on plan assets by 0.25% would have decreased 2003 pension income by approximately $1.1 million. Reducing the discount rate by 0.25% would have increased 2003 pension expense by approximately $0.3 million.

Unbilled Revenues

Revenues from retail electricity sales are recognized when monthly billings are made to customers for energy sold, based upon meter readings performed on a "cycle basis" during each month. In order to properly match revenue with related expenses (power costs, distribution expenses, etc), estimated "unbilled revenues" are accrued for electricity provided from meter read dates to each month-end. Such estimated unbilled revenues are based on PGE's net system load, the number of days from meter reading to the end of each calendar month, and current retail customer rates. Unbilled revenues, included within Current Assets on PGE's balance sheet, were $71 million and $84 million, respectively, at December 31, 2003 and 2002.

The calculation of unbilled revenues is affected by two estimates:

Line Losses
Net system load used to calculate unbilled revenues is adjusted for transmission and distribution line losses to estimate electricity delivered to retail customers. Historically, PGE has estimated line losses at approximately 2.6% for large industrial customers and 7% for other retail customers. To the extent that actual line losses differ from such estimates (due to temperature conditions, normal system aging, energy theft, etc), estimated unbilled revenues could be significantly different from actuals.

Consumption Allocation
Estimates of unbilled electricity use assume daily consumption is constant throughout each month. The effects of sudden or severe weather/temperature changes or other circumstances that may cause variations in consumption during the month is not readily determinable. To the extent that actual energy use from meter read dates to each month-end differs from estimated use based upon a constant usage assumption, estimated unbilled revenues could be significantly different from actuals.

Allowance for Uncollectible Accounts

Estimated provisions for uncollectible accounts receivable from retail electricity sales are recorded in the same period as the related revenues. These estimates are based on management's assessment of the probable collection of customer accounts, aging of accounts receivable, bad debt write-offs, and other factors. Certain circumstances and events can cause actual bad debt write-offs to vary from assumptions used in estimating uncollectible account provisions; these include general economic conditions, industry trends, deterioration of major customer credit worthiness, and higher defaults. PGE's earnings would be affected should such circumstances require a material adjustment to the Company's provision for uncollectible accounts.

Transactions with Related Parties

PGE's services to affiliated companies consist primarily of employee and corporate governance services. The Company also receives services from affiliated companies for employee benefit plans and corporate overheads. 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) approved by the Commission and the SEC. Any 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 can be resolved.

The ultimate disposition of the intercompany receivable and payable balances with Enron and its subsidiaries at December 31, 2003 is uncertain due to the bankruptcy proceedings of Enron and certain of its subsidiaries. The Company has recorded provisions against certain receivable balances due from Enron companies in bankruptcy. For further information, see Note 13, Related Party Transactions, in the Notes to Financial Statements, and "Enron Bankruptcy" in the Financial and Operating Outlook section.

Trading Activities Accounted for at Fair Value

PGE trading activities utilize electricity forward, swap, and option contracts, natural gas forward, swap, option, and futures contracts, and crude oil futures contracts to participate in electricity, natural gas, and crude oil 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, 2003, all energy trading contracts have a maturity of less than one year. The following tables indicate fair values, and changes in fair values, of PGE's trading contracts in 2003 and 2002, as well as the source of the fair value of the unrealized loss at December 31, 2002 (in millions):

	Unrealized Gain (Loss)	
	2003	2002
Unrealized gain of contracts as of January 1	$ (1)	$ 3
Less contracts realized during year:		
Contracts entered in prior years	-	(4)
Contracts entered in current year	(1)	1
Change in fair value attributable to market changes:		
Contracts entered in prior years	-	1
Contracts entered in current year	2	(2)
Unrealized gain (loss) of contracts as of December 31	$ -	$ (1)

	Unrealized Loss on Trading Contracts at Year End			
Source of Fair Value At December 31, 2002	Maturity 0 - 6 mos.	Maturity 6 - 12 mos.	Maturity over 1 yr.	Total Unrealized Loss
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 Sales

Weather adjusted retail energy sales decreased 1.0% in 2003 compared to 2002. An 8.7% decrease in industrial energy sales was partially offset by 2.0% and 1.0% increases, respectively, in residential and commercial energy sales. Industrial sales declined primarily due to reduced energy use in the second half of 2003 by two large customers, one of which elected to obtain its electricity requirements through co-generation. These two large customers represented 2.7% and 5%, respectively, of weather adjusted retail energy sales in 2003 and 2002. The increase in residential sales was largely attributable to an approximate 1.6% increase in customers served. PGE forecasts retail energy sales growth of approximately 1% in 2004.

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 normal levels in 2004. 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 2004 runoff at 87% of normal, compared to 83% in 2003 and 97% in 2002. Hydro conditions in both the Clackamas and Deschutes river systems, where PGE's facilities are located, are projected to be near normal in 2004. Efforts to restore salmon runs on the Columbia and Snake rivers may reduce the amount of water available for generation, which could affect the availability and price of purchased power.

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.

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 have 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.

Enron has entered into an agreement to sell PGE, which has been approved by the Bankruptcy Court. The sale requires certain regulatory approvals. If the sale does not close, 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. The Chapter 11 Plan is subject to creditor approval and confirmation by the Bankruptcy Court.

Enron Auction Processes Related to PGE

On November 18, 2003, Enron and Oregon Electric, a newly-formed Oregon limited liability company financially backed by investment funds managed by Texas Pacific Group, entered into an agreement under 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 FERC, and certain other regulatory agencies. On March 8, 2004, application for approval of the acquisition of PGE by Oregon Electric was filed with the OPUC. Filings will be made with the other agencies over the ensuing weeks. A decision is expected by year-end 2004.

If PGE is not sold, under the Chapter 11 Plan the shares of PGE's common stock will be distributed 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 Chapter 11 Plan or another filing related to the sale of PGE is approved, management cannot assess the impact on PGE's business and operations of a sale or the distribution of PGE's common 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, and its stock has been de-listed from the New York Stock Exchange. 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 -** PGE is owed approximately $73 million by Enron at December 31, 2003 (Merger Receivable). Such amount was to have been paid by Enron to PGE for price reductions granted to customers, as agreed to by Enron at the time it acquired PGE in 1997. Because of uncertainties associated with Enron's bankruptcy, PGE established a reserve for the entire amount of this receivable in December 2001. On October 15, 2002, PGE submitted proofs of claim to the Bankruptcy Court for amounts owed PGE by Enron and other bankrupt Enron subsidiaries, including $73 million for the Merger Receivable balance as of December 2, 2001, the date of Enron's bankruptcy filing. In addition, at December 31, 2003, PGE has outstanding accounts receivable of $8 million from Enron and its subsidiary companies which are part of the bankruptcy proceedings, consisting of $5 million due from PGH, $2

million from EPMI, and $1 million from Enron. Based on management's assessment of the realizability of these balances, a reserve of $5 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). Although at December 31, 2003 the total fair value of PGE Plan assets was $15 million higher than the projected benefit obligation on a SFAS No. 87 (Employers' Accounting for Pensions) basis, the PGE Plan was over-funded on an accumulated benefit obligation basis by about $68 million as of December 31, 2003. Enron's management has informed PGE that, as of December 31, 2003, the assets of the Enron Plan were less than the present value of all accrued benefits by approximately $60 million on a SFAS No. 87 basis and approximately $162 million on a plan termination basis. 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 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) in an amount equal to $424.1 million, including $352.3 million for the Enron Plan. 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. PBGC also currently estimates a UBL Claim of $57.5 million related to the PGE Plan. In addition, 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.

It is permissible, subject to applicable law, for separate pension plans established by companies in the same controlled group to be merged. Enron could direct that the PGE Plan be merged with the Enron Plan. If the plans were merged, 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, which insures pension plans, including the PGE Plan and the Enron Plan, and the PGE Plan's surplus would be undiminished. Merging the plans would reduce the value of PGE, the stock of which is an asset available to Enron's creditors. PGE's management believes that it is unlikely that either Enron or Enron's creditors would agree to support merging the two plans.

Enron cannot itself terminate the Enron Plan while it is underfunded unless it provides at least 60 days notice and the PBGC, in the case of solvent entities, or the Bankruptcy Court, in the case of insolvent entities, determines that each member of Enron's controlled group, including PGE, is in financial distress, as defined in ERISA. In the opinion of PGE management, PGE is a solvent entity that does not meet the financial distress test. Consequently, PGE management believes that it is unlikely that Enron can unilaterally terminate the Enron Plan while it is underfunded. However, Enron could, with consent of the PBGC (see discussion below), 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 ERISA.

The PBGC does have the authority, either by agreement with the plan administrator or upon application to and approval by a Federal District Court, to terminate and take over control of underfunded pension plans in certain circumstances. In order to initiate this process, the PBGC must determine that either the minimum funding standard for the plan (see discussion below) has not been met, or that the plan will not be able to pay benefits when due, or that there is a reasonable risk that long-run losses to the PBGC will be unreasonably increased or that certain distributions have been made from the plan. The court must determine that plan termination is necessary to protect participants, the plan, or the PBGC.

Upon termination of an underfunded pension plan, all members of the controlled group of the plan sponsor become jointly and severally liable for the underfunding, but are not obligated to pay until a demand for payment is made by the PBGC. The PBGC can demand payment from one or more of the members of the controlled group. If payment of the full amount demanded is not made, a lien in favor of the PBGC automatically arises against all of the assets of each 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 controlled group members. The PBGC may perfect the lien by appropriate filings. PGE management believes that the lien does not take priority over other previously perfected liens on the assets of a member 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 (see "Enron Auction Processes Related to PGE" in this section for additional information).

On January 30, 2004, the Bankruptcy Court entered an order authorizing Enron and its affiliated debtors to contribute $200 million to the Pension Plans to fund 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 Enron and its affiliated debtors are unsuccessful in their attempts to fund and terminate the Pension Plans, the PBGC were to take action to terminate the Pension Plans, and the PBGC did look solely to PGE to pay any underfunded amount in respect of 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 Enron's controlled group. Until the Enron Plan is terminated and the PBGC makes a demand on PGE to pay some or all of any underfunded amount, PGE has no liability for the underfunded amount and no termination liens 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 underfunded amount assessed by the PBGC. 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 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.

Based on discussions with Enron management, PGE's management understands that Enron has made all required contributions to date and plans to make the next contribution on April 15, 2004. 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 retirees 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 hard to insure or have preexisting conditions 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 agreement 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. Management understands that the IRS has completed an audit of the consolidated tax returns for 1996-2001.

B. 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 negotiation of the IRS audit for the taxable periods PGE was a member of Enron's consolidated federal income tax returns.

C. Enron's 2002 tax return was filed on September 12, 2003. As noted in paragraph B. above, Enron expects to have substantial NOLs from operations in years preceding 2002. Enron had 2002 NOLs sufficient to eliminate Enron's regular and alternative minimum income tax liabilities for 2002 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 seeks to apply $63 million in tax refunds admittedly due Enron against these claims. IRS claims for taxes and pre-petition interest have a priority over claims of general unsecured creditors, but claims for pre-petition penalties have no priority and claims for post-petition interest are not allowable in bankruptcy. The Company, along with other corporations in Enron's consolidated tax returns that are not in bankruptcy, are severally liable for pre-petition penalties and post-petition interest, as well as any portion of the claim allowed in the bankruptcy that the IRS does not collect from the debtors.

Enron's management has informed PGE management that Enron is negotiating with the IRS in an attempt to resolve issues raised by the IRS claims. If the parties do not reach a settlement, the Bankruptcy Court will decide the actual amount, if any, owed to the government with respect to tax, interest, and penalties.

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 Enron's bankruptcy, including the Chapter 11 Plan, may have on PGE. However, it does believe that the assets and liabilities of PGE will not become part of the Enron estate in bankruptcy. Although Enron owns all of PGE's common stock, 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. Regulatory and contractual protections restrict Enron access to PGE assets. Neither PGE nor Enron have guaranteed the obligations of the other. Under Oregon law and specific conditions imposed on Enron and PGE by the OPUC in connection with Enron's acquisition of PGE in the merger of Enron and PGC in 1997 (Merger Conditions), Enron's access to PGE cash or utility assets (through dividends or otherwise) is limited. Under the Merger Conditions, PGE cannot make any distribution to Enron that would cause PGE's common equity capital to fall below 48% of total PGE capitalization (excluding short-term borrowings) without OPUC approval. The Merger Conditions also include notification requirements regarding dividends and retained earnings transfers to Enron. PGE is required to maintain its own accounting system as well as separate debt and preferred stock ratings. PGE maintains its own cash management system and finances itself separately from Enron, on both a short- and long-term basis.

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.

Enron Debtor in Possession Financing

PGE has been informed by Enron management that shortly after the filing of its bankruptcy petition in December 2001, Enron entered into a debtor in possession credit agreement with Citicorp USA, Inc. and JPMorgan Chase Bank. The agreement was amended and restated in July 2002 and in May 2003. PGE management has been advised by Enron management and its legal advisors that, under the amended and restated agreement and related security agreement, all of which were approved by the Bankruptcy Court, Enron has pledged its stock in a number of subsidiaries, including PGE, to secure the repayment of any amounts due under the debtor in possession financing. The pledge will be automatically released upon a sale of PGE otherwise permitted under the terms of the credit agreement. Enron also granted the lenders a security interest in the proceeds of any sale of PGE. The lenders may not exercise substantially all of their rights to foreclose against the pledged shares of PGE stock or to exercise control over PGE unless and until the lenders have obtained the necessary regulatory approvals for the transfer of PGE stock to the lenders.

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 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. 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.

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, and signed a confidentiality agreement with Enron to permit it to participate in the Enron auction. The City did not participate in the overbid process following the Bankruptcy Court filing of Texas Pacific Group's agreement to purchase PGE. It is unclear at this time whether the City of Portland will continue to pursue the acquisition of PGE.

Peoples' Utility Districts
Proponents of the formation of Peoples' Utility Districts (PUDs) to acquire PGE's service territory obtained sufficient signatures on initiative petitions to place measures on election ballots in Multnomah, Yamhill, and Clackamas Counties. The formation initiative in Multnomah County, which appeared on the November 4, 2003 ballot, did not pass. On March 9, 2004, the voters in Yamhill County (which currently has approximately 24,000 PGE customers) also rejected a PUD initiative. In Clackamas County (which currently has approximately 158,000 PGE customers), the vote on formation of a PUD has been set for the May 18, 2004 ballot.

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.

Retail Rate Changes

General Rate Increase - 2001
Pursuant to PGE's 2001 general rate filing, the OPUC authorized retail price increases, effective October 1, 2001. The increase provided approximately $440 million in additional annual revenues, primarily as the result of significant increases in the cost of wholesale power and fuel. In its rate order, the Commission established PGE's return on equity at 10.5% and approved price increases of approximately 31.6% for residential customers, 37.3% for smaller business customers, and 53.2% for commercial and industrial customers. In addition, the OPUC approved a power cost adjustment mechanism covering the period October 2001 through December 2002 (described below).

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, 2003, the remaining balance to be collected was approximately $48 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, which is subject to a prudence review and audit currently being conducted by the OPUC, is being collected over a two-year period (2003-2004). Recovery from large industrial customers was completed during 2003. At December 31, 2003, the balance to be collected was approximately $10 million. PGE did not have a power cost adjustment mechanism in place for 2003.

Power Cost Price Decrease - 2003
The OPUC's 2001 general rate order contains a Power Cost Stipulation 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, a Resource Valuation Mechanism (RVM) utilizes a combination of market prices and the value of the Company's resources to establish power costs and set rates for energy services. The RVM process requires that PGE adjust its rates if projected power costs change from those included in the previous RVM rate process. It provides for an adjustment, filed annually in April and finalized in mid-November, which is effective January 1 of the following year.

PGE's first annual revision of its power supply costs under the RVM process forecast 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, effective January 1, 2003. Price decreases ranged from 2% for residential customers to between 9% and 17% for commercial and industrial customers. Rates for business customers are affected more by wholesale energy market prices, which decreased in the 2003 forecast. The smaller decrease in residential rates reflects 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.

Included in the 2003 price reduction was the effect of the Commission's disallowance of approximately $15 million related to four power purchase contracts, entered into in the first nine months of 2001, providing 125 megawatts of on-peak delivery in 2003. Also reflected in the price reduction was a resolution regarding the recovery period for PGE's power cost adjustment mechanism covering the period October 2001 through December 2002 and the effect of a settlement stipulation related to estimated 2003 power costs. Under the settlement, PGE agreed to reduce its recovery under the power cost adjustment mechanism by approximately $4.6 million, which was reflected as a reduction to the Company's earnings for 2002.

Power Cost Price Increase - 2004

In August 2003, PGE, OPUC staff, and intervenors entered into a stipulation, approved by the Commission, related to the Company's forecast of 2004 net variable power costs. Forecast adjustments were made to the price of certain wholesale power purchase contracts, reflecting recent electricity forward prices and certain other modifications and adjustments to estimated variable power and fuel costs. The 2004 RVM was finalized in November 2003, with new rates effective January 1, 2004. The average price for all customers increased by approximately 0.4%. Price adjustments range from a 2.3% decrease for industrial customers to increases of 2.8% and 1.9% for small commercial and residential customers, respectively. Price adjustments varied between customer classes primarily due to different collection periods for PGE's 2001-2002 power cost adjustment mechanism (see "Power Cost Adjustment Mechanisms" in this section for further information). Based upon projected energy sales, it is estimated that the price adjustments will increase PGE's 2004 revenues by approximately $4 million.

The stipulation also provides 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 from forecasted levels. PGE continues to work with customer groups and the OPUC staff on the development of a multi-year power cost adjustment mechanism, with particular focus on power cost variations caused by changes in hydro conditions.

Hydro Replacement Power Costs

In anticipation of the effects of adverse hydro conditions, PGE began in early 2003 to acquire replacement power resources for the expected shortfall in hydro-based power, incurring substantially higher variable power costs than those included in the Company's electric rates.

On February 11, 2003, PGE filed an Application for Deferral of Hydro Replacement Power Costs with the OPUC, in which the Company requested authorization to defer for later ratemaking treatment increases in power costs incurred from the application date through December 31, 2003. The Company's application requested authorization for the deferral of 95% of the difference between actual net variable power costs and those allowed in current rates. As proposed, the deferral would be adjusted for the impact that changes in load would otherwise have on net variable power costs. Under the Company's proposed methodology, approximately $25 million in power costs would have been deferred for future ratemaking treatment in 2003. On March 2, 2004, the OPUC denied PGE's application for the deferral of hydro replacement power costs incurred in 2003.

On December 31, 2003, PGE filed an Application for Deferral of 2004 Hydro Related Costs with the OPUC covering the year 2004. The application, similar to the February 2003 filing, requests the deferral of excess power costs resulting from hydro conditions that vary from those assumed in the 2004 RVM process. PGE continues to work with parties to develop a multi-year power cost adjustment mechanism that focuses on power cost variations caused by changes in hydro conditions.

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 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 March 2002, the Yakama Indian Nation filed a complaint with FERC, alleging that the Grant settlement contracts relating to the sale of power from the Project unreasonably restrain trade and violate various sections of the Federal Power Act and Public Law 83-544, and have harmed it monetarily and otherwise. FERC ruled on this complaint in November 2002, and while dismissing it, found that the non-compete clauses in the Grant settlement agreements violate section 10(h)(1) of the Federal Power Act. In December 2002, PGE filed a request for rehearing with FERC, and in April 2003, this request was denied. Both the Yakama Indian Nation and Grant appealed the November 2002 FERC decision and the appeals have been consolidated in the Ninth Circuit Court of Appeals.

In 2003, the Colville Confederated Tribes presented a claim to Douglas County PUD based upon alleged annual charges for the Wells Hydroelectric Project for the use of Colville tribal lands. The Colville Confederated Tribes 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. A settlement of this claim could affect the amount of energy PGE receives under the terms of the Company's purchased power contract or the price of the output of the Wells Hydroelectric Project purchased by PGE. Settlement discussions related to this matter are continuing.

For further information regarding the power purchase contracts on the mid-Columbia dams, see Note 7, Commitments, in the Notes to Financial Statements.

Nuclear Decommissioning

Approval of the Trojan Decommissioning Plan by the NRC and EFSC has allowed PGE to proceed with decommissioning activities, which are proceeding satisfactorily and within approved cost estimates. The steam generator, reactor containment vessel, and other major components have been removed and transported to the federal Hanford Nuclear Reservation 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 until permanent storage is available, was approved by the NRC in 2002. Fuel loading began in late 2002 and was completed in September 2003. PGE completed final radiological surveys of the Containment Building, Main Steam Support Structure, Electrical Penetration Area, Steam Generator Blow Down Building, and the majority of other building exteriors and supported the NRC's confirmatory surveys, with no significant findings or observations.

PGE has recorded an ARO for Trojan decommissioning of $104 million, measured at estimated fair value, as of December 31, 2003. The ARO estimate assumes the majority of decommissioning activities will be completed by 2005. 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 $15 million for 2004, compared to $21 million in 2003.

Transition activities, consisting of operating the spent fuel pool and securing the plant, ended in September 2003 when the fuel was transferred to dry storage, with remaining activities related primarily to decommissioning of the plant. These efforts position PGE to safely dispose of all radiological hazards, other than spent nuclear fuel, on the Trojan site and to initiate a final radiation survey to prove such hazards are no longer present.

In February 2002, the USDOE formally recommended that Yucca Mountain, Nevada become the nation's first long-term geologic (underground) repository for high-level radioactive waste produced in the United States. Lawsuits have been filed objecting to this recommendation. The proposed location is based on the conclusions of scientific studies of the site, conducted over 20 years, that 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 23, 2002 (P.L. 107-200). The USDOE must now apply to the NRC for an operating license. Further delays may create difficulties for PGE in disposing of its high-level radioactive waste by 2018. The availability of an off-site repository for the permanent storage of radioactive waste will allow PGE to remove spent nuclear fuel from the ISFSI, allowing final decommissioning and release of the Trojan site for unrestricted use. On January 6, 2004, the co-owners of Trojan, including PGE, 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. Damages sought are in excess of $200 million.

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. 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 expected that corresponding similar orders (limited in scope) will be issued to the Trojan ISFSI in late 2004 or in 2005. Until NRC requirements associated with the expected orders are determined, it is not known whether any related implementation costs will impact the Trojan decommissioning cost estimate and related funding requirements. However, as new security requirements are evaluated, any additional costs will be determined and decommissioning cost estimates revised as necessary.

For further information, see Note 12, Trojan Nuclear Plant, in the Notes to Financial Statements.

Receivables and Refunds on Wholesale Market Transactions

Receivables - California Wholesale Market
As of December 31, 2003, PGE has net accounts receivable balances totaling approximately $61 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 is pursuing collection of all past due amounts through the PX and PG&E bankruptcy proceedings and has filed a proof of claim in each of the proceedings. 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, including $22.5 million in 2003. 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 - In a June 2001 order adopting a price mitigation program for 11 states within the WECC area, the FERC referred to a settlement judge the issue of refunds for non federally-mandated transactions made between October 2, 2000 and June 20, 2001 in the spot markets operated by the ISO and the PX.

On July 25, 2001, the FERC issued another order establishing the scope of and methodology for calculating the refunds and ordering 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. Although no final dollar amounts were included in the certification, the recommended methodology indicated a potential refund by PGE of $20 million to $30 million.

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, issued in December 2002, 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 estimated that the modified methodology could increase the amount of the potential refunds by approximately $20 million, with the Company's potential liability estimated at between $20 million and $50 million.

Numerous parties, including PGE, filed requests for rehearing of various aspects of the March 26, 2003 order, including the pricing methodology. 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.

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.

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

Management cannot predict the ultimate outcome of the above matters related to wholesale transactions in California and the Pacific Northwest. However, it believes 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.

FERC Orders on Gaming and Anomalous Market Behaviors

Docket No. EL03-165-000

On June 25, 2003, the FERC ordered numerous entities, including PGE, that participated in the Western wholesale power market between January 1, 2000 and June 20, 2001 to show cause why their participation in specific behaviors and activities during that time period did not constitute gaming in violation of tariffs issued by the ISO and the PX. On August 27, 2003, prior to the due date for the show cause response, PGE and FERC Trial Staff settled Docket No. EL03-165-000 for a payment of $12,730, and with no admission of wrongdoing or liability on the part of PGE. This settlement, and numerous similar settlements involving other of the show cause respondents, have been contested by certain parties to the proceedings. By order issued March 8, 2004, FERC approved this settlement.

Docket No. IN03-10-000

Also on June 25, 2003, the FERC initiated a generic investigation into bids by market participants in ISO and PX markets between May 1, 2000 and October 2, 2000 at levels above $250/Mwh. Entities submitting such bids were required to demonstrate why such bids did not constitute anomalous market behavior under the ISO and PX Market Monitoring and Information Protocols and the extent to which they constituted legitimate business behavior. The FERC indicated that monetary remedies will be the disgorgement of unjust profits associated with violations, and that non-monetary remedies, such as revocation of market-based rates or revisions to codes of conduct, will also be considered. During the indicated time period, PGE made bids that exceeded $250/Mwh in both the ISO and PX markets. PGE submitted responses to FERC data requests in July and August 2003. Following additional analysis, PGE submitted a further response on March 5, 2004.

Challenge of the California Attorney General to Market-Based Rates

On March 20, 2002, the California Attorney General filed a complaint with FERC against various sellers in the wholesale power market, alleging that the FERC's market-based rates violate the Federal Power Act (FPA), and, even if market-based rate requirements are valid, that the quarterly transaction reports filed by sellers do not contain the transaction-specific information mandated by the FPA and the FERC. The complaint argued that refunds for amounts charged between market-based rates and cost-based rates should be ordered. The FERC denied the challenge to market-based rates and refused to order refunds, but did require sellers, including PGE, to refile their quarterly reports to include transaction-specific data. The California Attorney General appealed the FERC's decision to the Ninth Circuit Court of Appeals.

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 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 filed in 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, approved by the OPUC in September 2000, which 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 denying all of URP's challenges and approving the accounting and rate making elements of the settlement. URP appealed the decision to the Marion County Circuit Court and on November 7, 2003, the Court issued an opinion remanding the case to the OPUC for action to reduce rates or order refunds. The opinion does not specify the amount or timeframe of any reductions or refunds. PGE and the OPUC have appealed to the Oregon Court of Appeals.

In a separate legal proceeding, two class action suits were filed in Marion County Circuit Court against PGE on January 17, 2003 on behalf of two classes of electric service customers. One case seeks to represent current PGE customers that were customers during the period from April 1, 1995 to October 1, 2001 (Current Class) and the other case seeks to represent PGE customers that were customers during the period from April 1, 1995 to October 1, 2001, but who are no longer customers (Former Class). 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 March 24, 2003, PGE was served with two class action suits in Multnomah County Circuit Court, identical to the Marion County cases. On October 24, 2003, the Multnomah County suits were 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 rate order and settlement order, 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.

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.

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. A request has been made to the DEQ for a determination that no further work is required under the Voluntary Agreement. 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 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.

New Accounting Standards

FASB Interpretation No. 46 (FIN 46) Revised December 2003, Consolidation of Variable Interest Entities, an interpretation of ARB No. 51, was issued on December 24, 2003. FIN 46 provides guidance on the identification and consolidation of entities (termed "variable interest entities") for which control is achieved by means other than through voting rights. The application of FIN 46 is required in financial statements of entities that have interests in structures commonly referred to as special-purpose entities for periods ending after December 15, 2003. Application of FIN 46 for all other types of variable interest entities is required in financial statements for periods ending after March 15, 2004. Management does not believe that the application of FIN 46 will have a material impact on the Company's financial statements.

On January 12, 2004, the Financial Accounting Standards Board released FASB Staff Position No. FAS 106-1 (FSP 106-1), Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003. The Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Act) was signed into law on December 8, 2003 and introduces a prescription drug benefit under Medicare and provides a federal subsidy to sponsors of certain retiree health care benefit plans. Uncertainties exist regarding the effects of the Medicare Act on PGE's accumulated postretirement benefit obligation and net postretirement benefit costs and the accounting for those effects, if any. Under FSP 106-1, plan sponsors are allowed to elect a one-time deferral of the accounting for the Medicare Act. Amounts and disclosures related to PGE's accumulated postretirement benefit obligation and net postretirement benefit costs in the financial statements and accompanying notes do not reflect the effects of the Medicare Act on the plan. Specific authoritative guidance on the accounting for the federal subsidy is pending and that guidance, when issued, could require PGE to change previously reported information.

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 2003 were $0.1 million, $0.4 million, and zero, respectively, in 2002 were $0.1 million, $0.4 million, and zero, respectively, and in 2001 were $0.8 million, $3.6 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 2003 were $2.0 million, $3.7 million, and $1.0 million, respectively. For 2002 and 2001, 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. Additionally, PGE had power cost adjustment mechanisms in 2001-2002 that allowed the Company to defer, for future rate making treatment, actual net variable power costs that differed from certain baseline amounts approved by the OPUC (see "Power Cost Adjustment Mechanisms" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operations"). In 2003, 2002, and 2001, PGE did not reduce its non-trading value at risk by the amount of potential deferrals.

Foreign Currency Exchange Rate Risk

PGE is exposed 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, 2003, 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 10 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, 2003, 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 Value	Total	2004	2005	2006	2007	2008	After 2008
First Mortgage Bonds	$ 633	$ 583	$ 45	$ 18	$ -	$ 50	$ -	$470
Pollution Control Revenue Bonds	179	194	-	-	-	-	-	194
Other	232	206	11	12	11	20	-	152
Total	$1,044	$ 983	$ 56	$ 30	$ 11	$ 70	$ -	$816

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

Credit Risk

PGE is exposed to credit risk in its commodity price risk management activities related to potential nonperformance by counterparties. PGE manages the risk of counterparty default according to its credit policies by performing financial credit reviews and setting limits and monitoring exposures, requiring collateral when needed, and using standardized enabling agreements which allow for the netting of positive and negative exposures 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, 2003, 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, 2003. The tables reflect credit risk included in accounts receivable and price risk management assets, offset by related accounts payable and price risk management liabilities. The netting of counterparty balances is reflected only to the extent PGE has the contractual right of offset.

Non-Trading Activities

(Dollars in millions)

Rating	Credit Risk Before Collateral	Percentage of Total Exposure	Credit Collateral	Maturity of Credit Risk Exposure 2004	2005	2006	After 2006
Investment Grade	$ 85	97%	$ -	$ 37	$ 28	$ 20	$ -
Non-Investment Grade	3	3%	2	3	-	-	-
Total	$ 88	100%	$ 2	$ 40	$ 28	$ 20	$ -

Trading Activities

(Dollars in millions)

Rating	Credit Risk Before Collateral	Percentage of Total Exposure	Credit Collateral	Maturity of Credit Risk Exposure 2004	2005	2006	After 2006
Investment Grade	$ 7	100%	$ -	$ 7	$ -	$ -	$ -

Investment grade includes counterparties with a minimum senior unsecured debt credit rating of Baa3 assigned by Moody's Investor Service (Moody's) and BBB- assigned by Standard & Poor's Rating Group (S&P). Non-investment grade includes counterparties with credit ratings that are below investment grade. The credit exposure includes activity for electricity and natural gas forward, swap and option contracts. Credit collateral posted may be in the form of cash or letters of credit and may represent prepayment or credit exposure assurance.

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

Risk Management Committee

PGE has a Risk Management Committee, which is responsible for the oversight of commodity position and price risk, foreign currency risk, and credit risk related to wholesale energy marketing activities. PGE's Risk Management Committee 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 Risk Management Committee approves trading and credit 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, including accounting policies for 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 generally accepted accounting principles 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 2003 financial statements of PGE and issue a report thereon. PricewaterhouseCoopers LLP was engaged to audit the 2002 and 2001 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.

Independent Auditors' Report

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

We have audited the accompanying consolidated balance sheet of Portland General Electric Company and subsidiaries as of December 31, 2003, and the related consolidated statements of income, retained earnings, comprehensive income, and cash flows for the year then ended. Our audit also included the financial statement schedule for the year ended December 31, 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 audit.

We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of Portland General Electric Company and subsidiaries as of December 31, 2003, and the results of their operations and their cash flows for the year 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 year ended December 31, 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 18, 2004

Report of Independent Auditors

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 financial position of Portland General Electric Company and its subsidiaries at December 31, 2002 and the results of their operations and their cash flows for each of the two years 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 of 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.

As discussed in Note 1 to the consolidated financial statements, the Company changed its method of accounting for derivative instruments as of January 1, 2001.

PricewaterhouseCoopers LLP
Portland, Oregon
March 11, 2003

Portland General Electric Company and Subsidiaries
Consolidated Statements of Income

For the Years Ended December 31	2003	2002	2001
		(In Millions)	
Operating Revenues	$1,752	$1,855	$2,420
Operating Expenses			
Purchased power and fuel	1,028	1,157	1,734
Production and distribution	117	118	128
Administrative and other	148	147	151
Depreciation and amortization	213	161	170
Taxes other than income taxes	72	69	65
Income taxes	50	68	38
	1,628	1,720	2,286
Net Operating Income	124	135	134
Other Income (Deductions)			
Provision for uncollectible accounts receivable from affiliates	-	(6)	(79)
Miscellaneous	5	(2)	4
Income taxes	6	10	36
	11	2	(39)
Interest Charges			
Interest on long-term debt and other	79	67	68
Interest on short-term borrowings	-	4	4
	79	71	72
Net Income before cumulative effect of a change in accounting principle	56	66	23
Cumulative effect of a change in accounting principle, net of related taxes of $(1) in 2003 and $(6) in 2001	2	-	11
Net Income	58	66	34
Preferred Dividend Requirement	1	2	2
Income Available for Common Stock	$ 57	$ 64	$ 32

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	2003	2002	2001
		(In Millions)	
Balance at Beginning of Year	$ 488	$ 451	$ 459
Net Income	58	66	34
	546	517	493
Dividends Declared			
Common stock (non-cash dividend in 2002)	-	27	40
Preferred stock	1	2	2
	1	29	42
Balance at End of Year	$ 545	$ 488	$ 451

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	2003	2002	2001
		(In Millions)	
Accumulated other comprehensive income (loss) - Beginning of Year			
Unrealized gain (loss) on derivatives classified as cash flow hedges	$ 3	$ -	$ -
Minimum pension liability adjustment	(3)	(2)	-
Total	$ -	$ (2)	$ -
Net Income	$ 58	$ 66	$ 34
Other comprehensive income, net of tax:			
Unrealized gains (losses) on derivatives classified as cash flow hedges:			
Unrealized holding gain due to cumulative effect of change in accounting principle, net of related taxes of $(23)	-	-	35
Other unrealized holding gains (losses) arising during the period, net of related taxes of $(5) in 2003, $(4) in 2002, and $37 in 2001	9	7	(56)
Reclassification adjustment for contract settlements included in Net income, net of related taxes of $1 in 2003, $(1) in 2002, and $7 in 2001	(3)	1	(10)
Reclassification adjustment in net income due to discontinuance of cash flow hedges, net of related taxes of $6 in 2003 and $(19) in 2001	(9)	-	30
Reclassification of unrealized gains (losses) to SFAS No. 71 Regulatory (liability) asset, net of related taxes of $(2) in 2003, $3 in 2002, and $(1) in 2001	2	(5)	1
Total - Unrealized gains on derivatives classified as cash flow hedges	(1)	3	-
Minimum pension liability adjustment	(1)	(1)	(2)
Total Other comprehensive income (loss)	(2)	2	(2)
Comprehensive income	$ 56	$ 68	$ 32
Accumulated other comprehensive income (loss) - End of Year			
Unrealized gain on derivatives classified as cash flow hedges	$ 2	$ 3	$ -
Minimum pension liability adjustment	(4)	(3)	(2)
Total	$ (2)	$ -	$ (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	2003	2002
	(In Millions)	
Assets		
Electric Utility Plant - Original Cost		
Utility plant	$ 3,834	$ 3,706
Accumulated depreciation	(1,633)	(1,563)
	2,201	2,143
Other Property and Investments		
Receivable from parent (less allowance for uncollectible accounts of $73 and $81)	-	-
Nuclear decommissioning trust, at market value	35	31
Non-qualified benefit plan trust	67	68
Note receivable - Pelton Round Butte project sale	-	20
Miscellaneous	38	28
	140	147
Current Assets		
Cash and cash equivalents	109	51
Accounts and notes receivable (less allowance for uncollectible accounts of $51 and $28)	223	241
Unbilled revenues	72	84
Assets from price risk management activities	66	77
Inventories, at average cost	45	45
Prepayments and other	97	90
Deferred income taxes	-	3
	612	591
Deferred Charges		
Regulatory assets	387	544
Miscellaneous	32	30
	419	574
	$ 3,372	$ 3,455
Capitalization and Liabilities		
Capitalization		
Common stock equity		
Common stock, $3.75 par value per share, 100,000,000 shares authorized, 42,758,877 shares outstanding	$ 160	$ 160
Other paid-in capital - net	481	481
Retained earnings	545	488
Accumulated other comprehensive income (loss):		
Unrealized gain on derivatives classified as cash flow hedges	2	3
Minimum pension liability adjustment	(4)	(3)
Cumulative preferred stock subject to mandatory redemption	-	27
Limited voting junior preferred stock	-	-
Long-term debt	927	827
	2,111	1,983
Commitments and Contingencies (see Notes)		
Current Liabilities		
Long-term debt due within one year	56	191
Preferred stock maturing within one year	-	1
Accounts payable and other accruals	230	244
Liabilities from price risk management activities	44	80
Customer deposits	5	5
Accrued interest	20	15
Dividends payable	-	1
Accrued taxes	51	22
Deferred income taxes	8	-
	414	559
Other		
Deferred income taxes	349	383
Deferred investment tax credits	16	20
Trojan decommissioning and transition costs	104	186
Accumulated asset retirement obligation	17	-
Regulatory liabilities:		
Accumulated asset retirement removal costs	230	205
Other	27	16
Non-qualified benefit plan liabilities	66	62
Miscellaneous	38	41
	847	913
	$ 3,372	$ 3,455

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	2003	2002	2001
		(In Millions)	
Cash Flows From Operating Activities:			
Reconciliation of net income to net cash provided by (used in) operating activities			
Net income	$ 58	$ 66	$ 34
Non-cash items included in net income:			
Cumulative effect of a change in accounting principle, net of tax	(2)	-	(11)
Depreciation and amortization	213	161	170
Deferred income taxes	(22)	55	(31)
Net assets from price risk management activities	(30)	(11)	30
Power cost adjustment	51	(19)	(89)
Provision for uncollectible accounts receivable from affiliates	-	(1)	79
Other non-cash income and expenses (net)	19	(15)	27
Changes in working capital:			
Net margin deposit activity	-	89	(223)
(Increase) Decrease in receivables	9	6	(10)
Increase (Decrease) in payables	21	1	(30)
Other working capital items - net	(6)	(23)	(29)
Other - net	(4)	(4)	16
Net Cash Provided by (Used in) Operating Activities	307	305	(67)
Cash Flows From Investing Activities:			
Capital expenditures	(167)	(165)	(203)
Other - net	(11)	19	10
Net Cash Used in Investing Activities	(178)	(146)	(193)
Cash Flows From Financing Activities:			
Net Increase (Decrease) in short-term borrowings	-	(174)	158
Repayment of long-term debt	(402)	(174)	(58)
Issuance of long-term debt	342	250	150
Debt issue costs	(7)	(14)	-
Preferred stock retired	(3)	(2)	-
Dividends paid	(1)	(2)	(42)
Net Cash Provided by (Used in) Financing Activities	(71)	(116)	208
Increase (Decrease) in Cash and Cash Equivalents	58	43	(52)
Cash and Cash Equivalents, Beginning of Period	51	8	60
Cash and Cash Equivalents, End of Period	$ 109	$ 51	$ 8
Supplemental disclosures of cash flow information			
Cash paid during the period:			
Interest, net of amounts capitalized	$ 67	$ 62	$ 66
Income taxes	39	2	35
Non-cash investing activity:			
Sale of 33.33% interest in Pelton Round Butte hydroelectric project	-	28	-
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 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 51 incorporated cities, of which Portland and Salem are the largest, within a state-approved service area allocation of approximately 4,000 square miles. At the end of 2003, PGE's service area population was approximately 1.5 million, comprising about 43% of the state's population. The Company served approximately 754,000 retail customers at December 31, 2003.

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 filing.

On November 18, 2003, Enron and Oregon Electric Utility Company, LLC (Oregon Electric), a newly-formed Oregon limited liability company financially backed 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 OPUC, the FERC, and certain other regulatory agencies. See Note 16, 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. Intercompany balances and transactions have been eliminated.

Basis of Accounting

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

Use of Estimates

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

Contingencies

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

Reclassifications

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

In accordance with requirements of SFAS No. 143, Accounting for Asset Retirement Obligations, which became effective on January 1, 2003, asset retirement removal costs of $205 million were reclassified from Accumulated depreciation to Regulatory liabilities for 2002.

Revenues

Revenues are recognized when monthly billings are made to customers for energy sold. 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 rates.

Estimated provisions for uncollectible accounts receivable related to retail electricity sales are recorded in the same period as the related revenues. Provisions related to wholesale accounts receivable and unsettled positions are based on a periodic review and evaluation that includes liquidity risk, counterparty default risk, and contractual rights of offset when applicable.

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

PGE and the Bonneville Power Administration (BPA) have signed an agreement that provides cash benefits and power from BPA over a ten-year period beginning October 1, 2001. The benefits, which are passed directly to PGE's residential and small farm customers, are reflected within Purchased Power and Fuel expense. Amounts deferred under the Company's power cost adjustment mechanisms, as well as amortization of such amounts as recovery is made from customers, are also reflected within Purchased Power and Fuel expense (for further information, see "Power Cost Adjustment Mechanisms" under "Regulatory Assets and Liabilities" 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, natural gas forward, swap, option, and futures contracts, and crude oil futures contracts. On January 1, 2001, PGE adopted SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (as amended). Under SFAS No. 133, 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. Upon adoption of SFAS No. 133, PGE recorded after-tax gains of $11 million and $35 million in earnings and Other Comprehensive Income (OCI), respectively, from the cumulative effect of a change in accounting principle.

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 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 endeavor to minimize net power costs for retail customers.

The Oregon Public Utility Commission (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 not designated as 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 RVM. The regulatory asset or regulatory liability is reflected within Regulatory assets or Regulatory liabilities, respectively, on the Balance Sheet. Upon settlement, the regulatory asset or regulatory liability is reversed.

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

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 additional 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):

	2003	2002
Production	$1,359	$1,347
Transmission	277	349
Distribution	1,752	1,577
General	241	238
Intangible	116	114
Construction Work in Progress	89	81
Total	$3,834	$3,706

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 (53), Distribution (35), and General (12). 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 4.6% in 2003, 4.4% in 2002, and 4.2% in 2001. Estimated asset retirement removal costs included in depreciation expense were $58 million, $62 million, and $38 million in 2003, 2002, and 2001, respectively.

Periodic depreciation studies are conducted to update depreciation parameters (i.e. retirement dispersion patterns, average service lives, and net salvage rates). The studies also include estimates of Asset Retirement Obligations (AROs) and asset retirement removal costs. The studies are filed with the OPUC for approval to be included in a future rate proceeding. The last 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 asset retirement removal costs for assets without AROs. See Note 11, Asset Retirement Obligations, for further information.

Intangible plant, primarily computer software development costs, is amortized over estimated average service lives. Amortization expense for 2003, 2002, and 2001 was $13 million, $8 million, and $6 million, respectively, and is estimated at $14 million for 2004, $12 million for 2005, $13 million for 2006, $12 million for 2007, and $10 million for 2008. Accumulated amortization was $53 million and $46 million at December 31, 2003 and December 31, 2002, 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 2003, 2002, and 2001 were 9.0%, 5.0%, and 6.0%, respectively. AFDC from borrowed funds was $3 million in 2003, 2002 and 2001. AFDC from equity funds was $4 million in 2003, $2 million in 2002, and $3 million in 2001.

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, 2003 and 2002 were $23 million and $21 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, Related Party Transactions, and Note 16, 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 "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 $21 million at December 31, 2003 and $58 million at December 31, 2002. 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. Other trust investment balances were $46 million at December 31, 2003 and trust cash balances were $10 million at December 31, 2002.

Inventories

PGE's inventories are recorded at cost, which includes the purchase price (less discounts), applicable taxes, transportation and handling costs, 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):

	2003	2002
Coal	$ 6	$ 5
Fuel oil	11	14
Natural gas	2	1
Materials and supplies	24	23
Unallocated stores account	2	2
Total	$45	$45

Trojan Decommissioning and Transition Costs

Trojan decommissioning costs consist of those expenditures related to the decommissioning of the 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):

	2003	2002
Regulatory assets:		
Trojan decommissioning costs	$ 82	$158
Income taxes recoverable	113	116
Prior tax benefits recoverable	19	28
Debt reacquisition costs	24	18
Conservation investments – secured	29	38
Energy efficiency programs	21	31
Power cost adjustment mechanisms	58	109
Price risk management	-	11
Regulatory restructuring costs	23	20
Pelton Round Butte tax benefits recoverable	5	5
Miscellaneous	13	10
Total	$387	$544
Regulatory liabilities:		
Asset retirement obligations	$ 14	$ -
Accumulated asset retirement removal costs	230	205
Price risk management	8	7
Information technology costs	2	6
Miscellaneous	3	3
Total	$257	$ 221

Income taxes recoverable - The amount represents tax benefits previously flowed to customers through rates for temporary differences between book and tax reporting. The income taxes recoverable amount is reduced as temporary differences reverse and the increase in current tax expense is recovered in 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 $48 million at December 31, 2003 and $73 million at December 31, 2002 (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 $10 million at December 31, 2003 and $36 million at December 31, 2002 (including accrued interest).

PGE had no power cost adjustment mechanism for 2003 and currently has none in place for 2004.

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 collection in rates are recorded as regulatory assets or regulatory liabilities. Amounts recorded by PGE at December 31, 2003 and 2002 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.

Regulatory restructuring costs - The OPUC has authorized PGE to defer certain costs related to implementation of Oregon's electric restructuring law, of which approximately $6 million is currently being recovered in rates charged to customers over a six-year period. The remaining $17 million in implementation costs is being recovered over a five-year period beginning January 1, 2004.

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 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 began on January 1, 2004 and will continue for an approximate two-year period.

Asset retirement obligations - PGE adopted SFAS No. 143 on January 1, 2003. SFAS No. 143 requires the recognition of AROs, measured at estimated fair value, for legal obligations related to dismantlement and restoration costs associated with the retirement of tangible long-lived assets in the period in which the liability is incurred. Pursuant to regulation, AROs of rate-regulated long-lived assets are included as an allowable expense 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 as allowed in customer rates. At December 31, 2003 and 2002, accumulated asset retirement removal costs in Accumulated depreciation were reclassified to Regulatory liabilities, in accordance with requirements of SFAS No. 143 and SFAS No. 71. Accumulated asset retirement removal costs are included in PGE's rate base for ratemaking purposes.

Information technology costs - In PGE's 2001 general rate filing, the OPUC approved an estimated amount of capital expenditures related to the Company's Customer Information System (CIS) and Information Technology (IT) activities in the determination of PGE's 2002 revenue requirement. The 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 and $8 million were recorded in 2003 and 2002, respectively, to reflect the difference between actual and estimated revenue requirements related to CIS and IT capital expenditures. The amounts deferred in 2003 and 2002 are being refunded to customers through 2004. A $4 million annual deferral will continue until new base rates are established.

Recovery/refund period - As of December 31, 2003, 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 8 years.

New Accounting Standards

SFAS No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities, amends SFAS No. 133 to incorporate issues relating to the Derivatives Implementation Group process, other FASB projects dealing with financial instruments, and the application of the definition of a derivative. Under the amendment, an electricity forward contract must be a capacity contract, among other criteria, to qualify for the normal purchase and normal sale exception. The Statement is effective for contracts entered into or modified after June 30, 2003, except for provisions relating to Statement 133 Implementation Issues. Statement 133 Implementation Issues that have been effective for fiscal quarters that began prior to June 15, 2003 are applied in accordance with their respective effective dates. The adoption of SFAS No. 149 did not have a material effect on the financial statements of the Company.

SFAS No. 150, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity, establishes standards for classification and measurement of certain financial instruments with characteristics of both liabilities and equity. Included in SFAS No. 150 is a requirement that mandatorily redeemable financial instruments that the issuing company is obligated to redeem at a fixed amount and on specified or determinable dates must be reclassified as liabilities on the Balance Sheet. In addition, any dividends on such instruments are to be included in interest expense on the income statement. Reclassification of prior period amounts is not permitted. As required by SFAS No. 150, PGE's outstanding preferred stock that is mandatorily redeemable on fixed dates was reclassified to liabilities on July 1, 2003, and the Company began recording the related dividends as interest expense.

Emerging Issues Task Force Issue No. 01-8 (EITF 01-8), Determining Whether an Arrangement Contains a Lease, provides guidance in determining whether an arrangement or contract should be considered a lease subject to the requirements SFAS No. 13, Accounting for Leases. PGE implemented EITF 01-8 beginning July 1, 2003; arrangements and contracts entered into or modified prior to that date are not affected by the new guidance. The adoption of EITF 01-8 did not have an impact on the financial statements of the Company.

FASB Interpretation No. 46 (FIN 46) Revised December 2003, Consolidation of Variable Interest Entities, an interpretation of ARB No. 51, was issued on December 24, 2003. FIN 46 provides guidance on the identification and consolidation of entities (termed "variable interest entities") for which control is achieved by means other than through voting rights. The application of FIN 46 is required in financial statements of entities that have interests in structures commonly referred to as special-purpose entities for periods ending after December 15, 2003. Application of FIN 46 for all other types of variable interest entities is required in financial statements for periods ending after March 15, 2004. Management does not believe that the application of FIN 46 will have a material impact on the Company's financial statements.

On January 12, 2004, the Financial Accounting Standards Board released FASB Staff Position No. FAS 106-1 (FSP 106-1), Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003. The Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Act) was signed into law on December 8, 2003 and introduces a prescription drug benefit under Medicare and provides a federal subsidy to sponsors of certain retiree health care benefit plans. Uncertainties exist regarding the effects of the Medicare Act on PGE's accumulated postretirement benefit obligation and net postretirement benefit costs and the accounting for those effects, if any. Under FSP 106-1, plan sponsors are allowed to elect a one-time deferral of the accounting for the Medicare Act. Amounts and disclosures related to PGE's accumulated postretirement benefit obligation and net postretirement benefit costs in the financial statements and accompanying notes do not reflect the effects of the Medicare Act on the plan. Specific authoritative guidance on the accounting for the federal subsidy is pending and that guidance, when issued, could require PGE to change previously reported information.

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.

Emerging Issues Task Force Issue No. 03-11 (EITF 03-11), Reporting Gains and Losses on Derivative Instruments That are Subject to FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, and Not Held for Trading Purposes, requires that revenues and expenses associated with non-trading energy activities that are "booked out" (not physically settled) be reported on a net basis. EITF 03-11 is effective for all derivative contracts that settle after September 30, 2003 and does not require the reclassification of prior period amounts. Effective with the October 1, 2003 adoption of EITF 03-11, the non-physical settlement of non-trading electricity derivative activities, formerly recorded on a "gross" basis in both Operating Revenues and Purchased Power and Fuel expense, are recorded on a "net" basis in Purchased Power and Fuel expense. This change, which has no effect on margins from energy sales, net income, or cash flows, resulted in a $90 million decrease to both Operating Revenues and Purchased Power and Fuel expense for the fourth quarter of 2003. In addition, the change resulted in a 2,116 thousand MWh decrease in both non-trading wholesale energy sales and related purchases for the fourth quarter of 2003. The determination of those sales and purchases of electricity that would have been reported on a net basis had EITF 03-11 been historically applied is not practicable. Prospective application of EITF 03-11 will continue to result in a significant decrease in reported non-trading wholesale energy sales and purchases and related amounts reported in comparative financial statements.

Note 2 - Employee Benefits

Pension and Other Post-Retirement Plans
PGE participates in a non-contributory defined benefit pension plan with Portland General Holdings, Inc. (PGH) and its subsidiaries. Substantially all pension plan members are current or former PGE employees. The pension plan assets are held in a trust.

The Non-Qualified Benefit Plans in the accompanying table primarily represent obligations for a Supplemental Executive Retirement Plan (SERP). 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 and $21 million as of December 31, 2003 and 2002, respectively, 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. In addition, the $2 million recognized gain for 2003, $1 million recognized loss for 2002, and $8 million recognized loss for 2001 on the trust assets are included in net periodic benefit cost. The investments in marketable securities, consisting of money market, bond, and equity mutual funds, are classified as trading and recorded at fair value. For 2003, unrealized gains in marketable securities were $1 million.

PGE further 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 are made to a voluntary employees' beneficiary association (VEBA) to fund these plans. Costs of these plans, based upon an actuarial study, are included in rates charged to customers.

The measurement date for these plans is December 31. PGE does not expect to make contributions to the plans during 2004.

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

	Defined Benefit Pension Plan		Non-Qualified Benefit Plans		Other Benefits	
	2003	2002	2003	2002	2003	2002
Reconciliation of benefit obligation:						
Obligation at January 1	$ 353	$ 306	$ 19	$ 19	$ 42	$ 35
Service cost	11	9	-	-	1	1
Interest cost	23	21	1	2	3	3
Participants' contributions	-	-	-	-	1	1
Actuarial loss (gain)	30	32	3	-	1	5
Benefit payments	(17)	(15)	(2)	(2)	(3)	(3)
Obligation at December 31	$ 400	$ 353	$ 21	$ 19	$ 45	$ 42
Reconciliation of fair value of plan assets:						
Fair value of plan assets at January 1	$ 337	$ 397	$ 21	$ 22	$ 22	$ 28
Actual return (loss) on plan assets	95	(45)	2	(1)	6	(4)
Company contributions	-	-	1	2	-	-
Participants' contributions	-	-	-	-	1	1
Benefit payments	(17)	(15)	(2)	(2)	(3)	(3)
Fair value of plan assets at December 31	$ 415	$ 337	$ 22	$ 21	$ 26	$ 22
Funded status:						
Funded (unfunded) status at December 31 (*)	$ 15	$ (16)	$ 1	$ 2	$ (19)	$ (20)
Unrecognized transition (asset)/liability	(2)	(4)	-	-	2	3
Unrecognized prior service cost	5	7	1	2	2	2
Unrecognized gain (loss)	55	81	2	1	9	12
Prepaid pension cost (liability)	$ 73	$ 68	$ 4	$ 5	$ (6)	$ (3)
Accumulated benefit obligation	$ 347	$ 308	$ 17	$ 17	N/A	N/A
Amounts recognized in the Balance Sheet consist of:						
Prepaid benefit cost	$ 73	$ 68	$ 10	$ 8	$ (6)	$ (3)
Accumulated other comprehensive income	-	-	(6)	(3)	-	-
Net amount recognized	$ 73	$ 68	$ 4	$ 5	$ (6)	$ (3)
Assumptions:						
Discount rate used to calculate benefit obligation	6.25%	6.75%	6.25%	6.75%	6.25%	6.75%
Rate of increase in future compensation levels	4.0 - 9.5%	4.0 - 9.5%	5.5 - 5.75%	5.5 - 5.75%	4.0 - 9.5%	4.0 - 9.5%
Long-term rate of return on assets	9.00%	9.00%	N/A	N/A	8.61%	8.62%

	Defined Benefit Pension Plan			Non-Qualified Benefit Plans			Other Benefits		
	2003	2002	2001	2003	2002	2001	2003	2002	2001
Components of net periodic benefit cost:									
Service cost	$ 11	$ 9	$ 9	$ -	$ -	$ -	$ 1	$ 1	$ 1
Interest cost on benefit obligation	23	21	20	2	2	1	3	3	2
Expected return on plan assets	(39)	(39)	(37)	-	-	-	(1)	(2)	(2)
Amortization of transition asset	(2)	(2)	(2)	-	-	-	-	-	-
Amortization of prior service cost	1	1	1	-	-	-	-	-	-
Recognized (gain) loss	-	(3)	(6)	(2)	1	8	1	-	-
Net periodic benefit cost (income)	$ (6)	$ (13)	$ (15)	$ -	$ 3	$ 9	$ 4	$ 2	$ 1

(*) Due to the decline in the discount rate during 2003, the estimated obligation for the pension plan and for other benefits increased. In addition, the fair market value of assets in the pension trust and the VEBA 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 $15 million higher than the projected benefit obligation at December 31, 2003.

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 12% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2004. The rate was 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	$1.3	$(1.1)

The asset allocation for the Pension Plan at December 31, 2003 and 2002 and the target allocation for 2004, by asset category, are as follows:

Asset Category	Percentage of Plan Assets December 31		Target Allocation 2004
	2003	2002	
Equity Securities	72%	65%	67%
Debt Securities	28%	35%	33%
Total	100%	100%	100%

The asset allocation for the Non-Qualified Benefit Plans at December 31, 2003 and 2002 are as follows:

Asset Category	Percentage of Plan Assets December 31	
	2003	2002
Equity Securities	30%	-
Debt Securities	28%	-
TOLI Policies	42%	100%
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 2004 target allocations between equity and debt securities is approximately 45% - 55%.

The asset allocation for the Other Benefit Plans at December 31, 2003 and 2002, and the target allocation for 2004, by asset category, are as follows:

Asset Category	Percentage of Plan Assets December 31 2003	2002	Target Allocation 2004
Equity Securities	69%	78%	67%
Debt Securities	31%	22%	33%
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 will be 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). Obligations for the MDCP were $49 million and $45 million at December 31, 2003 and 2002, respectively (not included in table). The costs of the SERP and MDCP Plans are excluded from rates 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 $41 million and $42 million at December 31, 2003 and 2002, respectively. For 2003, unrealized gains in marketable securities were $2 million.

PGE sponsors additional non-qualified plans for certain employees and former directors. Assets held in support of these plans totaled $4 million and $5 million at December 31, 2003 and 2002, respectively.

401(k) Retirement Savings Plan

PGE participates in the Enron Corp. Savings Plan. The Enron Corp. Savings Plan included an Employee Stock Ownership Plan. Employee pre-tax contributions up to 6% of base pay were matched by employer contributions in the form of Enron common stock through mid-November 2001; such matching contributions for non-bargaining unit employees were terminated on December 1, 2001. The match continues for bargaining employees, in cash, under the union contract. On July 1, 2002, employer matching contributions were resumed for non-bargaining PGE employees. The Company matched two dollars for each pre-tax dollar contributed by non-bargaining employees up to 6% of base pay through December 31, 2002. Beginning January 1, 2003, non-bargaining employee pre-tax contributions are matched evenly by the Company up to 6% of base pay. All matching cash contributions are invested according to the employee's investment decisions. PGE made matching contributions to its employees' savings plan accounts of approximately $10 million, $10 million, and $9 million in 2003, 2002, and 2001, respectively.

Note 3 - Income Taxes

The following table shows 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):

	2003	2002	2001
Income Tax Expense			
Currently payable:			
Federal	$ 59	$ 5	$ 32
State and local	7	-	3
	66	5	35
Deferred income taxes:			
Federal	(19)	46	(25)
State and local	-	11	(5)
	(19)	57	(30)
Investment tax credit adjustments	(3)	(4)	(3)
Total income tax expense before cumulative effect of a change in accounting principle	$ 44	$ 58	$ 2
Provision Allocated to:			
Operations	$ 50	$ 68	$ 38
Other income and deductions	(6)	(10)	(36)
Total income tax expense before cumulative effect of a change in accounting principle	$ 44	$ 58	$ 2
Effective Tax Rate Computation:			
Computed tax based on statutory federal income tax rate (35%) applied to income before income taxes	$ 35	$ 44	$ 9
Flow through depreciation	7	8	5
State and local taxes - net of federal tax benefit	4	6	(1)
Investment tax credits	(3)	(4)	(3)
Excess deferred taxes	(1)	(1)	(1)
Deferred tax and other adjustments	2	5	(7)
Total income tax expense before cumulative effect of a change in accounting principle	$ 44	$ 58	$ 2
Effective tax rate	44.0%	46.8%	9.1% (*)

(*) The low effective tax rate for 2001 is primarily due to an approximate $5 million adjustment to deferred income taxes resulting from tax audit settlements, amended tax returns and the 2000 return to provision adjustment, $3 million in amortization of deferred investment tax credits, $2 million in state energy tax credits (net of the federal tax effect), and a $1 million tax effect related to non-taxable equity AFDC.

As of December 31, 2003 and 2002, the significant components of PGE's deferred income tax assets and liabilities were as follows (in millions):

	2003	2002
Deferred income tax assets		
Depreciation and amortization	$ 33	$ 18
Employee benefits	6	8
Allowance for uncollectible accounts	20	10
Land reclamation costs	8	8
Regulatory liabilities		
Asset retirement removal costs	91	81
Other	1	1
Other	18	14
Total deferred income tax assets	177	140
Deferred income tax liabilities		
Depreciation and amortization	440	409
Property taxes	5	5
Price risk management	6	1
Regulatory assets		
Prior tax benefits recoverable	7	11
Debt reacquisition costs	7	7
Conservation investments	11	14
Energy efficiency programs	12	13
Power cost adjustment	23	43
Miscellaneous	11	9
Other	12	8
Total deferred income tax liabilities	534	520
Net deferred income taxes	$ 357	$ 380
Classification of net deferred income taxes		
Included in current (assets) liabilities	$ 8	$ (3)
Included in non current liabilities	349	383
Net deferred income taxes	$ 357	$ 380

PGE has recorded deferred tax assets and liabilities for all temporary differences between the financial statement basis and tax basis of assets and liabilities. For further information, see Controlled Group Liability - Income Taxes in Note 16, Enron Bankruptcy.

Note 4 - Common and Preferred Stock

(Dollars in Millions)	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
December 31, 2001	42,758,877	$160	300,000	$ 30	-	-	$481
December 31, 2002	42,758,877	160	279,727	28	1	-	481
December 31, 2003	42,758,877	160	-	-	1	-	481

(*) SFAS No. 150 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 Facility 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 revolving credit facility prohibits the payment of any cash dividends or any other distribution by PGE.

Note 5 - Credit Facility and Debt

At December 31, 2003, PGE had a committed line of credit of $150 million. This 364-day revolving credit facility, which expires on May 27, 2004, is secured by First Mortgage Bonds issued by the Company and requires an annual fee of 0.25%. Under the facility, PGE has the option to use letters of credit, in addition to borrowings, totaling up to the $150 million. At December 31, 2003, PGE had utilized approximately $18 million in letters of credit.

PGE is evaluating alternatives for the replacement of its credit facility upon its May 27, 2004 expiration date, including the issuance of First Mortgage Bonds and/or new revolving credit facilities. As of December 31, 2003, the Company has sufficient capacity under its Indenture of Mortgage to issue additional First Mortgage Bonds for this purpose.

Due to PGE's increased liquidity and financial flexibility, the Company has regained its ability to access the commercial paper market, to which it had temporarily lost access due to ratings reductions for commercial paper by Moody's Investors Service and Fitch Ratings in May 2002. Management believes that its existing line of credit and cash from operations provide the Company with sufficient liquidity to meet its day-to-day cash requirements.

PGE is required to comply with various covenants contained in its current revolving credit facility. It contains a material adverse change clause and financial covenants that limit consolidated indebtedness, as defined in the facility, to 60% of total capitalization. It also requires that PGE maintain an interest coverage ratio, as defined in the facility, of not less than 3.75:1. In addition, the facility prohibits the payment of any cash dividends or any other distributions by PGE on its common stock. At December 31, 2003, the Company was in compliance with these covenants.

Short-term borrowings and related interest rates were as follows:

	2003	2002
As of December 31:	(Dollars in Millions)	
Aggregate short-term debt outstanding		
Commercial paper	-	-
Bank Loans	-	-
Weighted average interest rate*		
Commercial paper	-	-
Bank Loans	-	-
Committed lines of credit	$150	$222
For the year ended December 31:		
Average daily amounts of short-term debt outstanding		
Commercial paper	-	$58
Bank loans	-	57
Weighted daily average interest rate*		
Commercial paper	-	2.93%
Bank loans	-	3.50%
Maximum amount outstanding during the year		
Commercial paper	-	$150
Bank loans	-	135

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

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

Schedule of Long-Term Debt at December 31:	**2003**	**2002**
	(In Millions)	
First Mortgage Bonds		
Maturing 2003 (6.47%)	$ -	$ 40
Maturing 2004 - 2007 (7.15% - 9.07%) (a)	113	113
Maturing 2010 (8 1/8%)	150	150
Maturing 2012 (5.6675%)	100	100
Maturing 2013 (5.279% - 5.625%)	100	-
Maturing 2021 - 2033 (6.75% - 9.31%)	120	160
	583	563
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	75
6.91% Conservation Bonds maturing monthly to 2006 (a)	29	38
7.875% Notes due March 15, 2010	149	149
7.75% Series Cumulative Preferred Stock (a) (c)	25	-
Unamortized debt discount	(2)	(1)
	206	261
	983	1,018
Long-term debt due within one year (a)	(56)	(191)
Total long-term debt	$ 927	$ 827

(a) Due within one year; includes $45 million of 7.60 - 7.61% First Mortgage Bonds, $10 million of Conservation Bonds, and $1 million of 7.75% Series Cumulative Preferred Stock.

(b) Redeemable by PGE at 100% of principal amount since October 10, 2000.

(c) The mandatorily redeemable 7.75% Series Cumulative Preferred Stock (no par value) is classified as long-term debt at December 31, 2003; there were 249,727 shares outstanding. 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 2003, 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. Above classification reflects SFAS No. 150 requirement that financial instruments that are mandatorily redeemable at a fixed amount and on specified or determinable dates be reclassified as liabilities on the balance sheet for periods after June 30, 2003. Reclassification of prior period amounts is not permitted.

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

	2004	2005	2006	2007	2008	Thereafter	Total
Debt Maturities	$56	$30	$11	$70	$ -	$816	$983

Note 6 - Other Financial Instruments

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

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

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

Redeemable preferred stock - The fair value of redeemable preferred stock is based on quoted market prices. As required by SFAS No. 150, PGE's outstanding preferred stock was reclassified to liabilities on July 1, 2003. See Note 5, Credit Facility and Debt, for further information.

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 and equity instruments are as follows (in millions):

	2003		2002	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Preferred stock subject to mandatory redemption	$ -	$ -	$ 28	$ 23
Long-term debt including current maturities	$ 983	$1,044	$1,018	$1,010

Lower fair values in relation to carrying amounts for preferred stock and long-term debt in 2002 were due to downgrades by credit rating agencies, the effect of which is partially offset by decreased interest rates.

Note 7 - Commitments and Guarantee

Natural Gas Agreements

PGE has entered into agreements for the purchase and transmission of natural gas from domestic and Canadian sources for its natural gas-fired generating facilities. As of December 31, 2003, these agreements require net payments of approximately $48 million in 2004, $16 million in 2005, $16 million in 2006, $14 million in 2007 and 2008, and $51 million over the remaining years of the contracts, which expire at varying dates from 2004 to 2015. As of December 31, 2003, PGE also has agreements for the sale of natural gas to other counterparties of approximately $13 million in 2004.

Purchase Commitments

Certain commitments have been made for capital and other purchases for 2004. Such commitments, totaling $33 million as of December 31, 2003, relate to information systems, upgrades to production and distribution facilities, and 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 $12 million for 2004 and $4 million annually from 2005 through 2013.

Purchased Power

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

	Rocky Reach	Priest Rapids	Wanapum	Wells	Portland Hydro
Revenue bonds outstanding at December 31, 2003	$395	$185	$186	$151	$ 26
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:					
2003	$ 9	$ 4	$ 7	$ 7	$ 5
2002	8	4	8	6	4
2001	7	4	7	6	4
Contract expiration date	2011	2005	2009	2018	2017

PGE's share of debt service costs, excluding interest, is approximately $7 million in both 2004 and 2005, and $6 million in 2006, 2007, and 2008. Total minimum payments through the remainder of the contracts are estimated at $44 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 presented a claim to Douglas County PUD based upon alleged annual charges for the Wells Hydroelectric Project for the use of Colville tribal lands. The Colville Confederated Tribes 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. A settlement of this claim could affect the amount of energy PGE receives under the terms of the Company's purchased power contract or the price of the output of the Wells Hydroelectric Project purchased by PGE. Settlement discussions related to this matter are continuing.

As of December 31, 2003, PGE has power purchase contracts with other counterparties, requiring payments of approximately $577 million in 2004, $121 million in 2005, $117 million in 2006, $5 million in 2007 and 2008, and $23 million over the remaining years of the contracts. As of December 31, 2003, PGE has power sale contracts with other counterparties of approximately $316 million in 2004, $5 million in 2005, 2006, 2007, and 2008, and $20 million over the remaining years of the contracts, which expire at varying dates from 2004 to 2014. PGE also has power capacity contracts, as of December 31, 2003, that require payments of approximately $19 million annually through 2008; such payments are expected to average approximately $20 million from 2009 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 16,870 MWhs of electricity at December 31, 2003, all of which was received by the end of February 2004. The other exchange contract is with a winter-peaking Northwest utility to help meet the Company's summer-peaking power requirements. At December 31, 2003, PGE owed 8,553 MWhs of electricity, all of which was delivered by the end of February 2004.

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 2003, $9 million in 2002, and $20 million in 2001. The decrease in 2002 represents flowage easement payments formerly paid to the Tribes for the inundation of their property along the Deschutes River in conjunction with the operation of PGE's Pelton Round Butte hydroelectric project. Such payments terminated upon the January 2002 sale of a 33.33% interest in the project to the Tribes.

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

Year Ending December 31	Operating Leases (Net of Sublease Rentals)
2004	$10
2005	9
2006	6
2007	7
2008	7
Remainder	154
Total	$193

Included in the above schedule is approximately $88 million for PGE's headquarters complex. The original 25-year lease term of the Boardman coal-handling facility expires in 2005. 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. In January 2004, PGE 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 Utility defaults on the payments it owes under the P&T Agreements, PGE may be required to pay the damages owed by the Lessee to the lessor under the lease. Assuming no recovery from the Utility and no reduction in damages from mitigating sales or leases related to the Boardman Assets and P&T Agreements, the maximum amount that would be owed by PGE for the year 2004, is approximately $237 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, natural gas forward, swap, option, and futures contracts, and crude oil 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, natural gas, and crude oil 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, 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. 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 endeavor 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 daily 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 30, 2003 that will settle during the 12-month period from January 1, 2004 to December 31, 2004. Such valuation was based on forward price curves in effect on November 11, 2003 for electricity and natural gas. The timing difference between the recognition of gains and losses on certain derivative instruments and their realization and subsequent collection 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 2004, unrealized gains and losses on new 2004 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 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. In 2001, PGE recorded $26 million in net unrealized losses in earnings in its retail portfolio; this was fully offset by the recording of a SFAS No. 71 regulatory asset.

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 in 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 to 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.

In 2001, OCI activity consisted of $34 million of net unrealized losses in new contracts and changes in fair values, $17 million in net gains reclassified to earnings for contracts that settled during the period, and $49 million in net losses for the discontinuance of cash flow hedges due to the probability that the original forecasted transactions will not occur. The entire $2 million net unrealized loss in OCI was fully offset by the recording of a SFAS No. 71 regulatory asset.

Hedge ineffectiveness from cash flow hedges was not material in 2003, 2002, and 2001. As of December 31, 2003, the maximum length of time over which PGE is hedging its exposure to such transactions is approximately 15 months. The Company estimates that of the $4 million of net unrealized gains at December 31, 2003, $3 million will be reclassified into earnings within the next twelve months, and $1 million will be reclassified over the remaining three months.

Trading Activities

PGE utilizes electricity forward, swap, and option contracts, natural gas forward, swap, option, and futures contracts, and crude oil futures contracts to participate in electricity, natural gas, and crude oil 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.

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)		
	2003	2002	2001
Unrealized Gain (Loss)	$ 1	$(4)	$(10)
Realized Gain (Loss)	1	3	(1)
Net Gain (Loss) in Operating Revenues	$ 2	$(1)	$(11)

	Electricity Trading Megawatt Hours (thousands)		
	2003	2002	2001
Sales	13,551	11,292	3,862
Purchases	13,551	11,292	3,847

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

	Fair Values December 31, 2003		**Fair Values December 31, 2002**	
	Assets	**Liabilities**	**Assets**	**Liabilities**
Electric forward contracts	$22	$22	$27	$28
Natural gas swaps	2	2	20	20
Total	$24	$24	$47	$48

Note: All contracts have a maturity of one year or less.

Note 9 - Jointly Owned Plant

At December 31, 2003, 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	362	65.00	$ 394	$ 266
Colstrip 3&4	Colstrip, MT	Coal	296	20.00	464	301
Pelton/Round Butte	Madras, OR	Hydro	298	66.67	74	40

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.

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 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 filed in Marion County, Oregon Circuit Court, the Oregon Court of Appeals, and the Oregon Supreme Court on the issue of the OPUC's authority under Oregon law to grant recovery of and a return on the Trojan investment. The primary plaintiffs in the litigation were the Citizens' Utility Board (CUB) and the Utility Reform Project (URP). The Court of Appeals issued an opinion in 1998, stating that the OPUC does not have the authority to allow PGE to recover a return on the Trojan investment, but upholding the OPUC's authorization of PGE's recovery of the Trojan investment and ordering remand of the case to the OPUC. PGE and the OPUC requested the Oregon Supreme Court to conduct a review of the Court of Appeals decision on the return on investment issue. In addition, URP requested the Oregon Supreme Court to review the Court of Appeals decision on the return of investment issue. PGE requested the Oregon Supreme Court to suspend its review of the 1998 Court of Appeals opinion pending resolution of URP's complaint with the OPUC challenging the accounting and ratemaking elements of the settlement agreements approved by the OPUC in September 2000 (discussed below). On November 19, 2002, the Oregon Supreme Court dismissed PGE's and URP's petitions for review of the 1998 Oregon Court of Appeals decision. As a result, the 1998 Oregon Court of Appeals opinion stands and the case has been remanded to the OPUC.

While the petitions for review of the 1998 Court of Appeals decision were pending at the Oregon Supreme Court, in 2000, PGE, CUB, and the staff of the OPUC entered into agreements to settle the litigation related to PGE's recovery of its investment in the Trojan plant. URP did not participate in the settlement. The settlement, which was approved by the OPUC in September 2000, allowed PGE to remove from its balance sheet the remaining before-tax investment in Trojan of approximately $180 million at September 30, 2000, along with several largely offsetting regulatory liabilities. The largest of such amounts consisted of before-tax credits of approximately $79 million in customer benefits related to the previous settlement of power contracts with two other utilities and the approximately $80 million remaining credit due customers under terms of the Enron/PGC merger. The settlement also allows PGE recovery of approximately $47 million in income tax benefits related to the Trojan investment which had been flowed through to customers in prior years; such amount is being recovered from PGE customers, with no return on the unamortized balance, over an approximate five-year period, 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. 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 denying all of URP's challenges, and approving the accounting and ratemaking elements of the settlement. URP appealed the decision 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, from the inclusion of a return on investment of Trojan in the rates PGE charges its customers. In March 2003, the Company was served with two identical cases filed in Multnomah County Circuit Court that were dismissed on October 24, 2003.

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 rate order and settlement order, 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.

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.

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. The IBEW has appealed the decision. Management cannot predict the ultimate outcome of these grievances.

Other Legal Matters - PGE is party to various other claims, legal actions, and complaints arising in the ordinary course of business. Management cannot predict the ultimate outcome of these matters; however, it believes these matters will not have a material adverse impact on its financial statements.

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

PGE adopted SFAS No. 143 on January 1, 2003. SFAS No. 143 requires the recognition of AROs, measured at estimated fair value, for legal obligations related to dismantlement and restoration costs associated with the retirement of tangible long-lived assets in the period in which the liability is incurred. 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 coal plants, Beaver and Coyote Springs gas turbine plants, and the Bull Run hydro project, is deferred as a regulatory liability pursuant to SFAS No. 71.

The ARO associated with 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 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 2003 effects and 2002 and 2001 proforma effects to the balances and activities in AROs had SFAS No. 143 been in effect for all periods:

	Year Ended December 31, 2003	Proforma Year Ended December 31, 2002	Proforma Year Ended December 31, 2001
Beginning Balance	$ 137	$ 145	$ 149
Activity			
AROs incurred	-	-	-
Expenditures (Trojan)	(21)	(18)	(11)
Accretion	6	6	7
Revisions	(1)	4	-
Ending Balance	$ 121	$ 137	$ 145

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.

Accumulated Asset Retirement Removal Costs

Prior to SFAS No. 143, accumulated asset retirement removal costs were recorded in Accumulated depreciation. For 2003 and 2002, $230 million and $205 million, respectively, in accumulated asset retirement removal costs were reclassified from Accumulated depreciation to Regulatory liabilities, in accordance with SFAS No. 143 and SFAS No. 71.

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 until permanent storage is available, was approved by the NRC in 2002. Fuel loading began in late 2002 and was completed in early September 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 2003, PGE updated the decommissioning plan cost estimate to reflect revised inflation rates, in compliance with NRC procedures. In accordance with SFAS No. 143, the asset retirement obligation, measured at estimated fair value, is $104 million as of December 31, 2003 (see Note 11, Asset Retirement Obligations). The current estimate assumes that most of the remaining decommissioning activities will be completed by 2005, while costs to operate and maintain the ISFSI will continue to the year 2019. The original Trojan decommissioning plan was a site-specific estimate performed by an engineering firm experienced in estimating the cost of decommissioning nuclear plants. Updates to the plan's original estimate 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).

ASSET RETIREMENT OBLIGATION (ARO)
(In Millions)

Decommissioning estimate, 12/31/02	$	176
SFAS No. 143 Transition adjustment		(55)
2003 Expenditures		(21)
2003 Accretion		5
2003 Estimate Revisions		(1)
ARO 12/31/03	$	104
Total expenditures through 12/31/03	$	190

PGE collects $14 million annually from customers through 2011 for decommissioning costs (and records an equal amount 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 2003 to cover the costs of general decommissioning and activities in support of the ISFSI. With the completion of the fuel transfer to the ISFSI, PGE made an additional $12 million contribution to the external trust fund to fulfill NRC funding assurance requirements (see "Decommissioning Funding Assurance" below). Decommissioning funds are invested in investment-grade preferred stock, tax-exempt bonds, and U.S. Treasury bonds. Year-end balances are valued at

DECOMMISSIONING TRUST ACTIVITY
(In Millions)

		2003		2002
Beginning Balance	$	31	$	30
Activity				
Contributions		26		14
Earnings		-		-
Disbursements		(22)		(13)
Ending Balance	$	35	$	31

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 at a cost of 0.1 cent per kilowatt-hour sold at Trojan, which the Company paid during the period of plant operation. Significant delays are expected in the USDOE acceptance schedule of spent fuel from domestic utilities, with no federal repository expected to be available until at least 2010.

In February 2002, the USDOE formally recommended that Yucca Mountain, Nevada become the nation's first long-term geologic (underground) repository for high-level radioactive waste produced in the United States. Lawsuits have been filed objecting to this recommendation. The proposed location is based on the conclusions of scientific studies of the site, conducted over 20 years, that 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 23, 2002 (P.L. 107-200). The USDOE must now apply to the NRC for an operating license. Further delays may create difficulties for PGE in disposing of its high-level radioactive waste by 2018. The availability of an off-site repository for the permanent storage of radioactive waste will allow PGE to remove spent nuclear fuel from the ISFSI, allowing final decommissioning and release of the Trojan site for unrestricted use. 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 the enactment of the legislation. Based on Trojan's 1.1% usage of total industry enrichment services, PGE's share of the total funding requirement is approximately $17 million. Amounts are paid in 15 installments, beginning in 1993; 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. 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 expected that corresponding similar orders (limited in scope) will be issued to the Trojan ISFSI in late-2004 or in 2005. Until NRC requirements associated with the expected orders are determined, it is not known whether any related implementation costs will impact the Trojan decommissioning cost estimate and related funding requirements. However, as new security requirements are evaluated, any additional costs will be determined and decommissioning cost estimates revised as necessary.

Nuclear Insurance - The Price-Anderson Amendment of 1988 limits public liability claims that could arise from a nuclear incident and provides for loss sharing among all owners of nuclear reactor licenses. Because Trojan has been permanently de-fueled, the NRC has exempted PGE 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 from

$200 million to $100 million following a 3-year cool-down period of the nuclear fuel that remains on-site. All fuel is now stored on-site in the ISFSI. The NRC has allowed PGE to self-insure for on-site decontamination. PGE continues to carry non-contamination property insurance on the Trojan plant in the amount of $25 million.

Decommissioning Funding Assurance - Decommissioning funding assurance is required by the NRC for the amount by which total estimated future radiological decommissioning costs exceed actual balances in decommissioning trust funds. Upon completion of the transfer of nuclear fuel to the ISFSI, PGE was required to provide such funding assurance. PGE initially utilized a $13 million letter of credit under its revolving credit facility to meet the funding assurance requirement in September 2003. The Company replaced the letter of credit in December 2003 with a $12 million cash contribution (the funding assurance requirement at that time), eliminating costs associated with maintaining a letter of credit. The funding assurance requirement is expected to decrease through early 2005 as radiological decommissioning is completed. As the funding assurance requirement decreases, PGE's cash contribution will be returned to the Company.

Note 13 - Related Party Transactions

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

	December 31, 2003	December 31, 2002
Receivables from affiliated companies		
Enron Corp and other Enron Subsidiaries in Bankruptcy:		
Merger Receivable	$ 73	$ 81
Allowance for Uncollectible - Merger Receivable	(73)	(81)
Accounts Receivable[(a)]	3	2
Other Allowance for Uncollectible Accounts[(a)]	(3)	(2)
Other Enron Subsidiaries:		
Portland General Holding, Inc. - in Bankruptcy		
Accounts Receivable[(a)]	5	5
Other Allowance for Uncollectible Accounts [(a)]	(2)	(2)
PGH2 and its subsidiaries - not in Bankruptcy		
Accounts Receivable[(a)]	2	4
Note Receivable[(a)]	1	1
Payables to affiliated companies		
Enron Corp:		
Accounts Payable[(b)]	6	19
Income Taxes Payable[(c)]	36	7

[(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	2003	2002	2001
Revenues from affiliated companies			
Other Enron subsidiaries:			
Sales of electricity and transmission[a]	$ -	$ 1	$143
Expenses billed to affiliated companies			
Enron Corp:			
Intercompany services[b]	-	-	4
Portland General Holdings, Inc. - in Bankruptcy:			
Intercompany services[b]	-	1	1
PGH2 and its subsidiaries - not in Bankruptcy:			
Intercompany services[b]	1	1	1
Expenses billed from affiliated companies			
Enron Corp:			
Intercompany services[b]	34	32	30
Other Enron subsidiaries:			
Purchases of electricity[c]	-	-	140
Interest, net from affiliated companies			
Enron Corp:			
Interest income (expense)[d]	(8)	7	7
PGH2 and its subsidiaries:			
Interest income[d]	-	3	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 Purchased power and fuel on the Consolidated Statements of Income
[d] Included in Other Income (Deductions) on the Consolidated Statements of Income

Merger Receivable - Under terms of the companies' 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. 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. At December 31, 2003, Enron owed PGE approximately $73 million, including interest accrued prior to Enron's bankruptcy filing. The realization of the Merger Receivable from Enron is uncertain at this time due to Enron's bankruptcy. Based on this uncertainty, PGE established a reserve for the full amount of this receivable in December 2001.

On October 15, 2002, PGE submitted proofs of claim to the Bankruptcy Court for amounts owed PGE by Enron and other bankrupt Enron subsidiaries, including approximately $73 million (including accrued interest) for the Merger Receivable balance as of December 2, 2001, the date of Enron's bankruptcy filing. For further information, see Note 16, 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 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 $36 million income taxes payable to Enron at December 31, 2003 represents a net current income taxes payable of $29 million related to income taxes owed since December 24, 2002 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). During 2003, PGE paid $38 million to Enron for income taxes payable related to the first and second quarters of 2003. Further income tax payments were withheld until PGE's December 24, 2002 reconsolidation with Enron was agreed to by the IRS. Agreement was received from the IRS on February 2, 2004. The remaining payment of $29 million of post-petition period income taxes due Enron was made in February 2004. For further information, see Note 16, Enron Bankruptcy.

Intercompany Receivables and Payable - As part of its ongoing operations, PGE bills affiliates for various services provided. These include services provided by PGE employees along with other corporate services and are billed at the higher of cost or market. Also, PGE is billed for services received from affiliates, primarily for employee benefit plans and corporate overhead costs, at the lower of cost or market. Affiliated interest transactions 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.

<u>Enron</u> - PGE receives corporate overhead and employee benefit charges from Enron and provides incidental services to Enron. In 2003, Enron billed PGE approximately $20 million for retirement savings plan matching and medical and dental benefits and an additional $14 million for corporate overhead costs. In 2002, Enron billed PGE approximately $19 million for retirement savings plan matching and medical and dental benefits and $13 million for corporate overhead costs. In 2001, Enron billed PGE approximately $30 million for allocated overhead and other direct costs, including $7 million for retirement savings plan matching, $7 million for medical and dental benefits, and $14 million for corporate overhead costs. In 2001, PGE billed Enron $4 million, including $3 million for costs related to the termination of a proposed merger with Sierra Pacific Resources.

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 in March 2003. During 2003, PGE paid $47 million to Enron, consisting of $27 million for corporate overhead costs and $20 million for employee benefits. At December 31, 2003, PGE had a $6 million payable to Enron, consisting of $4 million for corporate overhead costs and $2 million for employee benefit costs. Included in the $6 million liability is $4 million related to the pre-petition period, which is included as an offset in PGE's proofs of claim. The $19 million payable to Enron at December 31, 2002 consisted of $17 million for corporate overheads and $2 million for employee benefits.

At December 31, 2003, Enron owed PGE $1 million related to employee benefits (pre-petition), which has been fully reserved and is included in PGE's proofs of claim filing.

<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.

At December 31, 2002, PGE was owed a net $2 million by EPMI for power sales and transmission services, which remained outstanding at December 31, 2003. EPMI is part of Enron's bankruptcy proceedings. Due to uncertainties associated with the realization of this receivable from EPMI, a $2 million reserve has been established. PGE included amounts owed by EPMI for power sales and transmission services in the proofs of claim filed with the Bankruptcy Court.

On April 17, 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. For further information, see Note 16, 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, 2003 and 2002, 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. 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. 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 PGH2, reflecting an assumption by PGH2 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 PGH2 was the result of negotiations between Enron and Sierra Pacific Resources related to the proposed sale of PGE and PGH2 to Sierra (the sale of which was later terminated in April 2001). In the proposed sale of PGE and PGH2 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 Natural, 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.

<u>PGH2 and its Subsidiaries - not in Bankruptcy</u> - PGH2, a wholly owned subsidiary of PGH, is the parent company of various subsidiaries that receive services from PGE. PGH2 and its subsidiaries are not part of Enron's or PGH's bankruptcy proceedings. PGH2 subsidiaries include Portland General Distribution, LLC (PGDC), a telecommunications company, Microclimates, Inc., a project management company, and Portland Energy Solutions Company, LLC (PES), which provides cooling services to buildings in downtown Portland, Oregon.

In July 2003, PGDC's 100% equity interest in Portland General Broadband Wireless, LLC was sold, and $3 million of the sales proceeds were used during the third quarter to reduce the outstanding accounts receivable balances owed by PGH2 and its subsidiaries to PGE.

During 2003, PGE billed PGH2 and its subsidiaries $1 million for employee and other corporate governance services. As of December 31, 2003, PGE had outstanding accounts and notes receivable from PGH2 and its subsidiaries of $3 million, comprised of $2 million for employee and other corporate governance services ($1 million each owed PGE by PGDC and PES) and a $1 million secured loan to PES. At December 31, 2002, PGE had outstanding accounts and notes receivable from PGH2 and its subsidiaries of $5 million, comprised of $2 million related to non-regulated asset sales, $2 million for employee and other corporate governance services, and a $1 million secured loan to PES.

PGE and PES have entered into a revolving credit agreement under which PGE has agreed to advance funds to PES to complete a district cooling system project. Advances accrue interest at 16% per annum. Interest paid by PES to PGE in excess of PGE's authorized cost of capital (9.083%) is deferred for future refund to PGE's customers. PGE also has a security interest in certain contracts and equipment related to the project. The agreement was to expire on April 1, 2003. In July 2003, the OPUC approved an amendment extending the agreement to March 31, 2004 and reducing the maximum loan amount from $2 million to $1.5 million. As of December 31, 2003, PES owed PGE $1.3 million, including accrued interest, under the agreement.

PES is in the process of selling substantially all of its assets to an unrelated third party. Final regulatory approvals related to the sale are anticipated to be received in April 2004. Proceeds from the sale are expected to be used to repay amounts owed to PGE, including amounts due under the revolving credit agreement and trade payables. PGE expects to file an application with the OPUC for approval of an amendment to extend the revolving credit agreement to June 30, 2004.

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 PGH2 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. Beginning in 2001, interest was no longer accrued on those other outstanding balances with Enron due to the proposed merger with Sierra Pacific Resources. Although the proposed merger was terminated in April 2001, interest accrual has not resumed.

Note 14 - Receivables and Refunds on Wholesale Transactions

Receivables - California Wholesale Market

As of December 31, 2003, PGE has net accounts receivable balances totaling approximately $61 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 is pursuing collection of all past due amounts through the PX and PG&E bankruptcy proceedings and has filed a proof of claim in each of the proceedings. 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, including $22.5 million recorded in 2003. 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

In a June 2001 order adopting a price mitigation program for 11 states within the Western Electricity Coordinating Council (WECC) area, the FERC referred to a settlement judge the issue of refunds for non federally-mandated transactions made between October 2, 2000 and June 20, 2001 in the spot markets operated by the ISO and the PX.

On July 25, 2001, the FERC issued another order establishing the scope of and methodology for calculating the refunds and ordering 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. Although no final dollar amounts were included in the certification, the recommended methodology indicated a potential refund by PGE of $20 million to $30 million.

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, issued in December 2002, 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 estimated that the modified methodology could increase the amount of the potential refunds by approximately $20 million, with the Company's potential liability estimated at between $20 million and $50 million.

Numerous parties, including PGE, filed requests for rehearing of various aspects of the March 26, 2003 order, including the pricing methodology. 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.

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.

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 - Investigations - Wholesale Power Markets

Settlement of Certain Matters

On September 26, 2003, PGE filed a settlement agreement (Settlement) between and among itself, the Trial Staff of the FERC, the California Attorney General, the California Public Utilities Commission, the City of Tacoma, Washington, the OPUC, and several other parties resolving certain cases and investigations related to electricity prices in California in 2000 - 2001. The Settlement resolves all alleged violations by the Company in the FERC's investigation under Docket No. EL02-114-000 of Enron trading strategies in the California wholesale power markets. The Settlement also resolves People of the State of California ex rel. Bill Lockyer, Attorney General v. Portland General Electric Company and Does 1 through 100 and related non-public investigations by the California Attorney General, except that the California Attorney General is not precluded from pursuing any willfully fraudulent acts or omissions not known at the time of the Settlement or any criminal acts or omissions. Finally, the Settlement resolves, as to PGE, the investigation proposed in the OPUC draft staff report on "Trading Activities by Portland General Electric Company, PacifiCorp, and Idaho Power Company during the Western Electricity Crisis of 2000-2001".

Under the Settlement, PGE paid a Settlement Amount of $8.5 million (included within "Other Income (Deductions)" on the Consolidated Statements of Income. The Settlement Amount was paid in January 2004, except for $0.8 million recorded as a Regulatory liability for refund to OPUC customers. PGE also filed an amendment to its FERC market-based rates tariff that imposes a cost-based cap on prices charged for new wholesale electricity sales transactions for a prospective period of twelve months, beginning December 19, 2003. In addition, PGE agreed to conduct annual training for its trading floor employees on code of conduct, standards of conduct, antitrust and ethics, and to retain for five years recordings of affiliate trading transactions, affiliate postings, and related accounting records. The Settlement provides that it will not be deemed an admission of fault or liability by PGE for any reason and implies no admission or fault by PGE. The Settlement, which was uncontested, was approved by the FERC on December 17, 2003.

Management does not believe that the cost-based cap on prices charged for new wholesale electricity sales transactions will have a material adverse impact on the financial statements.

Note 16 - 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) have 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.

Although Enron is continuing the sale process for PGE, under the Chapter 11 Plan, if PGE is not sold, 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. The Chapter 11 Plan is subject to creditor approval and confirmation by the Bankruptcy Court.

Management cannot predict with certainty what impact Enron's bankruptcy, including the Chapter 11 Plan, may have on PGE. However, it does believe that the assets and liabilities of PGE will not become part of the Enron estate in bankruptcy. Although Enron owns all of PGE's common stock, 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. Regulatory and contractual protections restrict Enron access to PGE assets. Under Oregon law and specific conditions imposed on Enron and PGE by the OPUC in connection with Enron's acquisition of PGE in the merger of Enron and PGC in 1997 (Merger Conditions), Enron's access to PGE cash or assets (through dividends or otherwise) is limited. Under the Merger Conditions, PGE cannot make any distribution to Enron that would cause PGE's common equity capital to fall below 48% of total PGE capitalization (excluding short-term borrowings) without OPUC approval. The Merger Conditions also include notification requirements regarding dividends and retained earnings transfers to Enron. PGE is required to maintain its own accounting system as well as separate debt and preferred stock ratings. PGE maintains its own cash management system and finances its operations separately from Enron, on both a short-term and long-term basis. 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.

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, PGE is owed approximately $73 million by Enron at December 31, 2003 (Merger Receivable). Such amount was to have been paid to the Company for customer price reductions granted to customers, as agreed to by Enron at the time it acquired PGE in 1997. Because of uncertainties associated with Enron's bankruptcy, PGE has established a reserve for the full amount of this receivable, which was recorded in December 2001. On October 15, 2002, PGE submitted proofs of claim to the Bankruptcy Court for amounts owed PGE by Enron and other bankrupt Enron subsidiaries, including approximately $73 million (including accrued interest) for the Merger Receivable balance as of December 2, 2001, the date of Enron's bankruptcy filing. In addition, at December 31, 2003, PGE has outstanding accounts receivable of $8 million from Enron and its subsidiary companies which are part of the

bankruptcy proceedings, consisting of $5 million due from PGH, $2 million from EPMI, and $1 million from Enron. Based on management's assessment of the realizability of these balances, a reserve of $5 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.

<u>Pension Plans</u>

The pension plan for the employees of PGE (the PGE Plan) is separate from the Enron Corp. Cash Balance Plan (the Enron Plan). Although at December 31, 2003, the total fair value of PGE Plan assets was $15 million higher than the projected benefit obligation on a SFAS No. 87 (Employers' Accounting for Pensions) basis, the PGE Plan was over-funded on an accumulated benefit obligation basis by about $68 million as of December 31, 2003. Enron's management has informed PGE that, as of December 31, 2003, the assets of the Enron Plan were less than the present value of all accrued benefits by approximately $60 million on a SFAS No. 87 basis and approximately $162 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) in an amount equal to $424.1 million, including $352.3 million for the Enron Plan. 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. PBGC also currently estimates a UBL Claim of $57.5 million related to the PGE Plan. In addition, 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.

Subject to applicable law, separate pension plans established by companies in the same controlled group may be merged. If the Enron Plan and PGE Plan were merged, 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.

Because the Enron Plan is underfunded and Enron is in bankruptcy, 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 members of the Enron 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 and plans to make the next contribution on April 15, 2004.

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, as stated in the Disclosure Statement and as set forth in Enron's motion, 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. However, there can be no assurance that this proposal will remain in the Plan ultimately approved by the Debtors' creditors or that the Bankruptcy Court will approve Enron's motion. In addition, as stated in the Disclosure Statement, there can be no assurance at this time that the funding and termination will be approved by the Bankruptcy Court or that, upon such approval, Enron will have the ability to obtain funding on acceptable terms.

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 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 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 hard to insure or have preexisting 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. Enron obtained an agreement from the IRS on February 2, 2004 stipulating that PGE did become a member of the Enron consolidated group on December 24, 2002. Due to the uncertainty with the reconsolidation during 2003, PGE held certain tax payments due Enron. 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. Management understands that the IRS has completed an audit of the consolidated tax returns for 1996-2001.

B. 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 negotiation of the IRS audit for the taxable periods PGE was a member of Enron's consolidated federal income tax returns.

C. Enron's 2002 tax return was filed on September 12, 2003. As noted in paragraph B. above, Enron expects to have substantial NOLs from operations in years preceding 2002. Enron had 2002 NOLs sufficient to eliminate Enron's regular and alternative minimum income tax liabilities for 2002 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 seeks to apply $63 million in tax refunds admittedly due Enron against these claims. IRS claims for taxes and pre-petition interest have a priority over claims of general unsecured creditors, but claims for pre-petition penalties have no priority and claims for post-petition interest are not allowable in bankruptcy. The Company, along with other corporations in Enron's consolidated tax returns that are not in bankruptcy, are severally liable for pre-petition penalties and post-petition interest, as well as any portion of the claim allowed in the bankruptcy that the IRS does not collect from the debtors.

Enron's management has informed PGE management that Enron is negotiating with the IRS in an attempt to resolve issues raised by the IRS claims. If the parties do not reach a settlement, the Bankruptcy Court will decide the actual amount, if any, owed to the government with respect to tax, interest, and penalties.

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.

Enron Debtor in Possession Financing - PGE has been informed by Enron management that shortly after the filing of its bankruptcy petition in December 2001, Enron entered into a debtor in possession credit agreement with Citicorp USA, Inc. and JPMorgan Chase Bank. The agreement was amended and restated in July 2002 and in May 2003. PGE management has been advised by Enron management and its legal advisors that, under the amended and restated agreement and related security agreement, all of which were approved by the Bankruptcy Court, Enron has pledged its stock in a number of subsidiaries, including PGE, to secure the repayment of any amounts due under the debtor in possession financing. The pledge will be automatically released upon a sale of PGE otherwise permitted under the terms of the credit agreement. Enron also granted the lenders a security interest in the proceeds of any sale of PGE. The lenders may not exercise substantially all of their rights to foreclose against the pledged shares of PGE stock or to exercise control over PGE unless and until the lenders have obtained the necessary regulatory approvals for the transfer of PGE stock to the lenders.

Enron Auction Processes Related to PGE

On November 18, 2003, Enron and Oregon Electric Utility Company, LLC (Oregon Electric), a newly-formed Oregon limited liability company financially backed 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 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 FERC, and certain other regulatory agencies. On March 8, 2004, application for approval of the acquisition of PGE by Oregon Electric was filed with the OPUC. Filings will be made with the other agencies over the ensuing weeks. A decision is expected by year-end 2004.

If PGE is not sold, under the Chapter 11 Plan the shares of PGE's common stock will be distributed 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 Chapter 11 Plan or another filing related to the sale of PGE is approved, 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 2003 AND 2002 (Unaudited)

	March 31	June 30	September 30	December 31	Total
			(In Millions)		
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
2002					
Operating revenues (c)	$464	$439	$458	$494	$1,855
Net operating income (d)	51	33	24	27	135
Net income before cumulative effect of a change in accounting principle	36	16	8	6	66
Net income	36	16	8	6	66
Income available for Common stock	35	16	7	6	64

(a) The fourth quarter of 2003 reflects a $90 million reduction in Operating revenues related to the October 1, 2003 adoption of EITF 03-11, Reporting Gains and Losses on Derivative Instruments That are Subject to FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, and Not Held for Trading Purposes. Amounts for periods prior to October 1, 2003 have not been reclassified. For further information, see New Accounting Standards in 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. For further information, see Note 14, Receivables and Refunds on Wholesale Transactions, and Note 15, Investigations - Wholesale Power Markets, in the Notes to Financial Statements.

(c) Amounts for the first and second quarter of 2002 have been reclassified from those previously reported, in accordance with requirements of EITF 02-3, Accounting for Contracts Involved in Energy Trading and Risk Management Activities, which was adopted effective in the third quarter of 2002. For further information, see Note 1, Summary of Significant Accounting Policies, in the Notes to Financial Statements.

(d) The fourth quarter of 2002 includes 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. This adjustment was identified during a fourth quarter 2002 analysis of temporary differences related to deferred income taxes. This temporary difference arises when property taxes are fully deductible for tax purposes at the lien date of year one (i.e. July 1) while financial accounting establishes a prepayment and amortizes the prepayment to expense over a property tax fiscal year from July 1 of one year to June 30 of the next year. Based on ratemaking history, the Company believes that this deferred tax relates to the flow through of tax benefits to customers prior to 1993, which were to be recovered by the Company in a future period. Management assessed the potential for recovering this amount from customers, and based on the available evidence is unable to represent that recovery is probable.

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

(a) PricewaterhouseCoopers LLP

(i) On January 9, 2004, the Audit Committee of the Board of Directors of PGE dismissed PricewaterhouseCoopers LLP (PwC) as PGE's independent auditors. The decision to replace PwC was not related to its conduct of the audit of PGE, but rather the consideration of a potential claim against PwC by Enron or its affiliates that could potentially raise concerns about PwC's independence at some future point. Although PGE is a wholly owned subsidiary of Enron, it is not a debtor in the Enron bankruptcy proceedings.

(ii) The reports of PwC on the financial statements of PGE as of December 31, 2002 and 2001, and for the years then ended, contained no adverse opinion or disclaimer of opinion and were not qualified or modified as to uncertainty, audit scope or accounting principle.

(iii) The Audit Committee of PGE's Board of Directors approved the change in certifying auditors on January 9, 2004.

(iv) In connection with its audits of the financial statements of PGE as of December 31, 2002 and 2001, and for the years then ended and through January 9, 2004, there have been no disagreements with PwC on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure, which disagreements if not resolved to the satisfaction of PwC, would have caused them to make reference thereto in their report on the financial statements for such years.

(v) During the years ended December 31, 2002 and 2001 and through January 9, 2004, there have been no reportable events as defined in Regulation S-K Item 304(a)(1)(v).

(vi) PGE requested that PwC furnish it with a letter addressed to the SEC stating whether or not it agrees with the above statements. Such letter was provided, stating that PwC agreed with the above statements.

(b) Deloitte & Touche LLP

PGE engaged Deloitte & Touche LLP (D&T) as its new independent auditors as of January 12, 2004. During the two most recent fiscal years and through January 9, 2004, neither PGE nor any one on behalf of PGE has consulted with D&T regarding (i) the application of accounting principles to a specific transaction, either completed or proposed, or the type of audit opinion that might be rendered on PGE's financial statements; or (ii) any matter that was either the subject of a disagreement, as that term is defined in Item 304(a)(1)(iv) of Regulation S-K and the related instructions to Item 304 of Regulation S-K, or a reportable event, as that term is defined in Item 304(a)(1)(v) of Regulation S-K.

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.

(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.

Part III

Item 10. Directors and Executive Officers of the Registrant

Directors of the Registrant [1]

JOHN W. BALLANTINE, age 58 — Director since February 1, 2004

Mr. Ballantine has been an active private investor since 1998, when he retired from First Chicago NBD Corporation where he served as Executive Vice President and Chief Risk Management Officer. During his 28-year career with First Chicago, Mr. Ballantine was responsible for International Banking operations, New York operations, Latin American Banking, Corporate Planning, US Financial Institutions business and a variety of trust operations. Mr. Ballantine has been a director of Enron[2] since May 30, 2002. 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.

ROBERT S. BINGHAM, age 55 — 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 his tenure with Kroll Zolfo Cooper, LLC, he has served as Associate Director of Restructuring for Enron[2] since February 2002. 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.

Mr. Bingham is the Chair of PGE's Audit Committee and a member of PGE's Compensation Committee. The Board has determined that Mr. 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.

RAYMOND M. BOWEN, JR., age 44 — Director since July 2, 2002

Mr. Bowen has served as Executive Vice President, Chief Financial Officer and Treasurer of Enron[2] since January 2002. From November 2001 to January 2002, he served as Executive Vice President and Treasurer of Enron. He served from September 2000 to November 2001 as Chief Operating Officer of Enron Industrial Markets[3]. He served as Managing Director Commercial Transactions Group, for Enron North America[4], from August 1999 to August 2000. Mr. Bowen joined Enron in 1996 as Vice President of Enron Capital and Trade Resources[4].

Mr. Bowen is a member of PGE's Compensation Committee and PGE's Audit Committee.

Directors of the Registrant [1] - Continued

PEGGY Y. FOWLER, age 52 — 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. Ms. Fowler began her career with PGE in 1974 as a chemist. She also serves on the boards of Regence Blue Cross/Blue Shield of Oregon, Legacy Health Systems, 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[5] (an Enron affiliate) from March 1999 until June 2003.

CORBIN A. MCNEILL, JR., age 64 — Director since February 1, 2004

Mr. McNeill is Chair of the Board. He is the retired 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. Mr. McNeill has been a Director of Enron[2] since May 30, 2002. He also serves on the boards of CrossCountry Energy Corporation (an Enron affiliate), Associated Electric & Gas Services Limited, and the U.S. Naval Academy Alumni Association.

ROBERT H. WALLS, JR., age 43 — 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 for Enron from October 1999 until March 2002 and General Counsel for Enron International Inc[6] (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 for Enron Power Corp.[7] He is also a member of the Advisory Board of the Texas Children's Cancer Center.

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(1) As of February 29, 2004. Directors of PGE hold office until the next annual meeting of shareholders or until their respective successors are duly elected and qualified. Stanley C. Horton resigned as a Director of PGE, effective October 31, 2003. James J. Piro resigned as a Director of PGE, effective January 31, 2004, but remains an Executive Officer of PGE.

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

(3) Enron Industrial Markets filed for bankruptcy protection on December 4, 2001.

(4) Enron North America Corp., successor to Enron Capital and Trade Resources Corp., filed for bankruptcy protection on December 2, 2001.

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

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

(7) 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	52	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.
Frederick D. Miller Executive Vice President, Public Policy and Consumer Services	61	Appointed to current position on June 1, 2002. Served as Executive Vice President, Retail and Distribution Services from May 2001 until appointed to current position. Served as Senior Vice President, Public Policy and Administrative Services from December 1996 to May 2001. Served as Vice President, Public Affairs and Corporate Services from October 1992 until December 1996. Served as Director of Executive Department, State of Oregon, from 1987 until October 1992.
James J. Piro Executive Vice President, Finance, Chief Financial Officer and Treasurer	51	Appointed to current position on July 25, 2002. Served as Senior Vice President Finance, Chief Financial Officer and Treasurer from May 2001 until appointed to current position. Served as Vice President, Chief Financial Officer and Treasurer from November 2000 until May 2001. Served as Vice President, Business Development from February 1998 until November 2000. Served as General Manager, Planning Support, Analysis and Forecasting, from 1992 until 1998. Mr. Piro also served as Chief Financial Officer and Senior Vice President of Portland General Holdings, Inc[2] (an Enron affiliate) from July 2001 until June 2003.

Executive Officers of the Registrant [1] (Continued)

Name	Age	Business Experience
Arleen N. Barnett Vice President, Human Resources and Information Technology	52	Appointed to current position on May 1, 2001. Served as Vice President, Human Resources from February 1998 until appointed to current position. 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.
Carol A. Dillin Vice President, Public Policy	46	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, System Engineering, Utility Services and Customer Service	54	Appointed to current position on October 1, 2003. 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, Customer Resource Strategy and Generation Engineering	53	Appointed to current position on July 1, 2002. Served as Vice President, Power Supply, Resource Development and Engineering Services from January 2001 until appointed to current position. 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 and Federal Affairs	47	Appointed to current position on June 7, 2002. Served as Vice President, Public Policy and Regulatory Affairs from May 2001 until appointed to current position. 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	45	Appointed to current position on September 16, 2002. Served as Vice President, Risk Management Reporting, Controls and Credit from May 2001 until appointed to current position. 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	56	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	61	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.
Christopher D. Ryder Vice President, Residential and Business Services	54	Appointed to current position on October 2, 2002. Served as Vice President, Customer Service Delivery from July 1997 until appointed to current position. Served as General Manager, Customer Services and Southern Region Operations from 1996 until July 1997. Served as General Manager, Customer Services, Marketing and Sales from 1992 to 1996.
Stephen M. Quennoz Vice President, Generation	56	Appointed to current position on January 30, 2001. Served as Vice President Nuclear and Thermal Operations from October 1998 until appointed to current position. Joined PGE in 1991 and held the position of Trojan Site Executive and Plant General Manager from 1993 to 1998.

(1) As of February 29, 2004. Officers of PGE are elected for one-year terms or until their successors are elected and qualified. Frederick D. Miller will retire as an Executive Officer of PGE, effective March 31, 2004.

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

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 is a "code of ethics" as defined by the 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 the nature of the amendment or waiver, its effective date, and to whom it applies on the Company's web site.

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 2003.

Item 11. Executive Compensation

Summary Compensation Table

The following indicates total compensation earned for the years ended December 31, 2003, 2002, and 2001 by the Chief Executive Officer and the four most highly compensated executive officers of PGE (the "Named Executive Officers").

		Annual Compensation		
Name and Principal Position	Year	Salary(1)	Bonus	All Other Compensation(2)
Peggy Y. Fowler	2003	$350,004	$240,000	$413,792
Chief Executive Officer	2002	345,836	200,000	433,192
and President	2001	329,063	400,000	38,561
Frederick D. Miller	2003	$225,399	$140,000	$211,716
Executive Vice President, Public	2002	228,703	100,000	212,399
Policy and Consumer Services	2001	218,230	150,000	26,418
James J. Piro	2003	$215,129	$160,000	$136,970
Executive Vice President, Finance	2002	208,210	120,000	141,198
Chief Financial Officer and Treasurer	2001	183,670	170,000	13,782
Douglas R. Nichols	2003	$190,008	$138,000	$119,716
Vice President, General Counsel	2002	181,424	90,000	12,157
and Secretary	2001	161,558	85,000	9,677
Arleen N. Barnett	2003	$194,376	$ 95,000	$124,303
Vice President, Human Resources	2002	188,664	75,000	12,573
and Information Technology	2001	170,202	95,000	10,665

(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 2003:

	Split Dollar Insurance Cost	Contributions to 401(k) and MDCP	Retention Payments	Total
Peggy Y. Fowler	$638	$13,154	$400,000	$413,792
Frederick D. Miller	935	10,781	200,000	211,716
James J. Piro	-	11,970	125,000	136,970
Douglas R. Nichols	-	10,716	109,000	119,716
Arleen N. Barnett	-	9,303	115,000	124,303

Certain of the Named Executive Officers held unreleased restricted shares of Enron common stock as of December 31, 2003. Aggregate restricted stock holdings listed below are valued at $0.03 per share, the closing price of Enron common stock on December 31, 2003.

	Aggregate Restricted Stock Holdings	
	Aggregate Shares (#)	Value
Peggy Y. Fowler	-	$ -
Frederick D. Miller	-	-
James J. Piro	490	15
Douglas R. Nichols	330	10
Arleen N. Barnett	-	-

Each of the Named Executive Officers held options to purchase Enron common stock as of December 31, 2003. The following lists information concerning options to purchase shares of Enron common stock that were exercised by the Named Executive Officers during 2003 and the total options and their value held by each at December 31, 2003.

	Aggregated Option/SAR Exercises During 2003 And Option/SAR Values at December 31, 2003					
	Shares Acquired on Exercise	Value Realized	Exercisable Options	Unexercisable Options	Exercisable Amount	Unexercisable Amount
Peggy Y. Fowler	-	$ -	38,678	-	$ -	$ -
Frederick D. Miller	-	-	4,176	-	-	-
James J. Piro	-	-	90,570	-	-	-
Douglas R. Nichols	-	-	14,162	-	-	-
Arleen N. Barnett	-	-	10,594	-	-	-

The cost to exercise each option exceeded the market value of the underlying Enron common stock at December 31, 2003.

No new grants were made to Named Executive Officers during 2003.

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 $200,000 (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	12	15	20	25+
Pension Plan Only	$ 200,000	$ 38,161	$ 47,700	$ 63,601	$ 79,501
	300,000	108,000	135,000	157,500	180,000
	400,000	144,000	180,000	210,000	240,000
	500,000	180,000	225,000	262,500	300,000
	600,000	216,000	270,000	315,000	360,000
	700,000	252,000	315,000	367,500	420,000
	800,000	288,000	360,000	420,000	480,000
	900,000	324,000	405,000	472,500	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 $200,000 or pay annual benefits in excess of $160,000. 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). The PGE Pension Plan benefits are reduced 2% per year from age 60 to 64 and 5% per year from age 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.

Peggy Y. Fowler and Frederick D. Miller are participants 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, 30; Frederick D. Miller, 12; James J. Piro, 24; Douglas R. Nichols, 13; and Arleen N. Barnett, 25. Under the Company's SERP, the following Named Executive Officers are eligible to retire without a reduction in benefits upon attainment of the following ages: Peggy Y. Fowler, 55; and Frederick D. Miller, 62.

Compensation of Directors
There were no compensation arrangements for, or fees paid to, Directors of PGE solely for their service as Directors in 2003. Beginning in 2004, independent directors will receive 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.

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 Raymond M. Bowen, Jr. and Robert S. Bingham. Salary increases, annual incentive awards, and long-term incentive grants (if any) are reviewed annually to ensure consistency with PGE's total compensation philosophy.

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

On January 9, 2004, the Audit Committee of the Board of Directors of PGE dismissed PricewaterhouseCoopers LLP (PwC) as PGE's independent auditors. On January 12, 2004, Deloitte & Touche LLP (Deloitte & Touche) was engaged as PGE's new independent auditors. (For further information, see Item 9. - "Changes in and Disagreements with Accountants on Accounting and Financial Disclosure").

The Company incurred the following fees for services rendered by PwC and Deloitte & Touche for the years ended December 31, 2003 and 2002.

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, 2003 and 2002 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.

	PwC	Deloitte & Touche
2003	$ 366,359	$850,000
2002	1,041,555 (a)	-

(a) Includes fees of $481,723 for the re-audit of year 2000, necessitated by reclassifications required by EITF 02-3. See Note 8, Price Risk Management, in the Notes to Financial Statements.

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
2003	$ 137,183	$ -
2002	112,342	-

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
2003	$ 2,975	$ -
2002	-	-

All Other Fees

None.

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

During 2003, the Audit Committee established a policy to require 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 2003 was rendered by permanent full time employees and partners of Deloitte & Touche.

Part IV

Item 15. Exhibits, Financial Statement Schedules, and Reports on Form 8-K

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

Exhibits

See Exhibit Index on Page 139 of this report.

(b) **Reports on Form 8-K**

November 10, 2003 - Item 5. Other Events: Proposed Acquisition of Portland General Electric Company, Refunds on Wholesale Transactions - Pacific Northwest.

November 26, 2003 - Item 5. Other Events: FERC Investigations - Wholesale Power Markets, Portland General Electric Company v. Hardy Myers, Attorney General of the State of Oregon.

January 9, 2004 - Item 4. Changes in Registrant's Certifying Accountant.

January 9, 2004 - Item 4. Changes in Registrant's Certifying Accountant (Form 8-K/A)

February 5, 2004 - Item 5. Other Event: Proposed Acquisition of Portland General Electric Company.

Portland General Electric Company and Subsidiaries
Schedule II - Consolidated Valuation and Qualifying Accounts
For the Years Ended December 31, 2003, 2002, and 2001
(In Millions)

	Allowance for Uncollectible Accounts
Balance at January 1, 2001	$ 10
Provision charged to income	96
Amounts written off, less recoveries	(4)
Balance at December 31, 2001	102
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

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 19, 2004

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

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

/s/ Peggy Y. Fowler Peggy Y. Fowler	Chief Executive Officer and President and Director	March 19, 2004
/s/ James J. Piro James J. Piro	Executive Vice President, Finance Chief Financial Officer and Treasurer	March 19, 2004
/s/ Kirk M. Stevens Kirk M. Stevens	Controller and Assistant Treasurer	March 19, 2004
*John W. Ballantine	Director	March 19, 2004
*Robert S. Bingham	Director	March 19, 2004
*Raymond M. Bowen, Jr.	Director	March 19, 2004
*Corbin A. McNeill, Jr.	Director	March 19, 2004
*Robert H. Walls, Jr.	Director	March 19, 2004

*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 (filed herewith).
(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)].

PORTLAND GENERAL ELECTRIC COMPANY
AND SUBSIDIARIES

EXHIBIT INDEX

Number		Exhibit
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)].
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)].

PORTLAND GENERAL ELECTRIC COMPANY
AND SUBSIDIARIES

EXHIBIT INDEX

Number		Exhibit
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)].
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 (filed herewith).
10.16	*	Portland General Electric Company Management Deferred Compensation Plan, dated March 12, 2003 [Form 10-Q for the quarter ended March 31, 2003, Exhibit (10)].
10.17	*	Portland General Electric Company Supplemental Executive Retirement Plan, dated March 12, 2003 [Form 10-Q for the quarter ended March 31, 2003, Exhibit (10)].
10.18	*	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)].
10.19	*	Portland General Electric Company Umbrella Trust for Management, dated March 12, 2003 [Form 10-Q for the quarter ended March 31, 2003, Exhibit (10)].
10.20		Director Compensation Arrangement (filed herewith).
(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 Pursuant to Securities Exchange Act Rule 13a-14(a) for Annual Report on Form 10-K for the fiscal year ended December 31, 2003 (filed herewith).
31.2	Certification of Chief Financial Officer of Portland General Electric Company Pursuant to Securities Exchange Act Rule 13a-14(a) for Annual Report on Form 10-K for the fiscal year ended December 31, 2003 (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, for Annual Report on Form 10-K for the fiscal year ended December 31, 2003 (furnished herewith).

* Incorporated by reference as indicated.

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

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

EXHIBIT 31.1

CERTIFICATION OF
CHIEF EXECUTIVE OFFICER
OF PORTLAND GENERAL ELECTRIC COMPANY

I, Peggy Y. Fowler, certify that:

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

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

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

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

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

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

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

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

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

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

Date: March 19, 2004

/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 19, 2004

/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, Chief Financial Officer, 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, 2003, 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
Date: March 19, 2004	Date: March 19, 2004