PORTLAND GENERAL ELECTRIC CO /OR/
Form 10-K/A
March 17, 2003

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, 2002
		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. [ ]

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes ___ No _X_

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

Number of shares of Common Stock outstanding as of February 28, 2003: 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 wholesale electric energy to utilities, brokers, and power marketers located throughout the western United States. PGE's service area is located entirely within Oregon and covers 3,150 square miles. It includes 51 incorporated cities, of which Portland and Salem are the largest, within a state-approved service area allocation of 4,095 square miles. PGE estimates that at the end of 2002 its service area population was approximately 1.5 million, comprising about 44% of the state's population. The Company added approximately 7,700 customers during 2002, and at December 31, 2002 served approximately 743,000 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 is not included in the filing. For further information, see "Enron Bankruptcy" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operations".

As of December 31, 2002, PGE had 2,757 employees. This compares to 2,790 and 2,781 employees at December 31, 2001 and 2000, respectively. A total of 902 employees are covered under agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 885 employees for a three-year period effective from March 1, 2002 through February 29, 2004; negotiations on a new agreement are expected to begin in late 2003. In addition, 17 employees at Coyote Springs are covered under an agreement effective from September 1, 2001 through August 1, 2006.

Operating Revenues

Retail

PGE's diverse retail customer base has helped mitigate the effects of a significant downturn in Oregon's economy. Residential, the largest customer class, comprises about 88% of the Company's total number of customers, and in 2002 provided 38% of total retail MWh energy sales and 41% of retail tariff revenues. Residential demand is sensitive to the effects of weather, with revenues highest during the winter heating season. Commercial and industrial customers provided about 40% and 19%, respectively, of retail tariff revenues in 2002. While total retail MWh energy sales decreased somewhat from 2001, reflecting the continuing effect of Oregon's slow economy and conservation efforts, revenues increased approximately 35%, reflecting a general rate increase that became effective October 1, 2001 (see "Retail Rate Changes" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operations" for further information).

Commercial and industrial customer classes are not dominated by any single industry. While the 20 largest customers constitute about 21% 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 3.4% of PGE's total retail load.

Wholesale (Non-Trading)

Non-trading wholesale electricity sales related to activities to serve retail load requirements comprised about 21% of total operating revenues in 2002, down from about 54% in 2001. The decrease was due to significantly lower wholesale market prices. 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 power for its customers at the lowest cost available.

Other Operating Revenues

Other operating revenues include net gains and losses from PGE's energy trading activities, which seek to take advantage of price movements in electricity, natural gas, and crude oil. 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:

	2002	2001	2000
Operating Revenues (Millions)			
Residential	$ 567	$ 475	$ 448

Commercial(*)	550	424	388
Industrial	269	222	208
Tariff Revenues	1,386	1,121	1,044
Accrued (Collected) Revenues	82	(31)	14
Retail	1,468	1,090	1,058
Wholesale (Non-Trading)	391	1,313	774
Other Operating Revenues:			
Trading Activities - net	(1)	(11)	30
Other	(3)	28	25
Total Operating Revenues	$1,855	$2,420	$1,887
Megawatt-Hours Sold (Thousands)			
Residential	7,058	7,080	7,433
Commercial(*)	7,101	7,285	7,527
Industrial	4,612	4,675	4,912
Retail	18,771	19,040	19,872
Wholesale (Non-Trading)	12,645	9,764	12,858
Trading Activities - net	-	15	(55)
Total MWh Sold	31,416	28,819	32,675

(*) Includes public street lighting

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

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 further ensures that prices are fair, equitable, 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.

PGE is also subject to the jurisdiction of the FERC with regard to the transmission and sale of wholesale electric energy, licensing of hydroelectric projects, and certain other matters. The Company is a "licensee" and a "public utility" as those terms are used in the Federal Power Act and is, therefore, also subject to regulation by the FERC as to accounting policies and practices, transmission and wholesale prices, issuance of short-term debt, and other matters.

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. In October 2002, the NRC approved the transfer of spent nuclear fuel from the Trojan spent fuel pool to the Trojan Independent Spent Fuel Storage Installation (ISFSI), using a separately licensed dry cask storage system. 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 11, Trojan Nuclear Plant, in the Notes to Financial Statements.

PGE is a subsidiary of a holding company (Enron) exempt under PUHCA, except for Section 9(a)(2) with respect to the acquisition of the securities of other public utilities. In February 2002, Enron applied to the SEC to continue its exemption, which requires that PGE's utility activities be predominantly intrastate in nature. In February 2003, an administrative law judge issued an Initial Decision that denied Enron's application for exemption, holding that PGE does not meet the criteria to be predominantly intrastate in character. On February 27, 2003, Enron filed a Petition for Review with the SEC requesting that the SEC review the Administrative Law Judge's Initial Decision, reverse such Initial Decision, and find that Enron is entitled to exemption from PUHCA. Filing of the Petition for Review stays the effect of the Initial Decision until such time as the SEC may act on the Petition for Review. The SEC could act on the Petition for Review at any time. Possible responses of the SEC to the Petition for Review include setting the matter down for further hearings before the full Commission or summarily affirming the Initial Decision. In the event that the Initial Decision is affirmed by the SEC, either summarily or after further hearings, Enron could be required to register as a holding company under PUHCA, and PGE would become a subsidiary of a registered holding company. If PGE were be become a subsidiary of a registered holding company, it would become subject to additional regulation by the SEC with respect to certain matters, including transactions with Enron. For further information, see "Public Utility Holding Company Act of 1935" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operations".

Regulatory Matters

Electric Power Industry Restructuring

On March 1, 2002, Oregon's electric energy industry restructuring plan was implemented. Signed into law as State Senate Bill 1149 by the state's governor, the restructuring plan provides all commercial and industrial customers of investor-owned utilities direct access to competing energy suppliers. Residential and small business 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. For further information, see "Regulation and Competition" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operations".

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

Integrated Resource Plan

In August 2002, PGE filed a new Integrated Resource Plan. In its Plan, PGE describes its strategy to meet the electric energy needs of its customers, with an emphasis on cost, long-term price stability, and supply reliability. The Plan, which considers resource actions over the next two to three years, includes reduced reliance on short-term wholesale power contracts and increased emphasis on longer-term supplies. It also considers future investment in additional generating resources (including upgrades to existing resources), an increase in renewable resources, long-term power purchases, and meeting seasonal peaking requirements through seasonal exchanges, demand-side management, capacity tolling contracts, and combustion turbine development.

PGE filed a supplement to the Plan on February 28, 2003. The OPUC has initiated a schedule for input and review, with an acknowledgement of the Company's Plan, as supplemented, anticipated by mid-2003. PGE then anticipates issuing a request for proposals (RFP) to acquire energy and capacity resources. The Company will continue to evaluate its options with regard to the construction of additional generation (including the Port Westward gas turbine project), and the availability of reasonably priced medium to long-term power purchases from the market. PGE will continue to monitor changes in economic conditions and the effect of restructuring legislation that allows large customers to purchase power directly from electricity service suppliers.

Based upon results of the RFP process, PGE will update its action plan with specific resource recommendations and request acknowledgement that the Company's final action plan is consistent with least cost planning principles established by the OPUC.

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 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 be on a single network transmission tariff, and operational control of the transmission network would be administered by the RTO. The FERC is expected to issue further clarification on the implementation of Standard Market Design in April 2003.

In September 2002, the formation plan of RTO West received preliminary FERC approval, with some modification and further development of certain details. In its approval ruling, the FERC stated that the RTO West proposal, with some modification and further development of certain details, will satisfy Order No. 2000 requirements and provide a basic framework for a Standard Market Design for the West.

Also in September 2002, the FERC granted preliminary approval of a proposed rate structure for TransConnect, a new company proposed by PGE and two other regional utilities. Conditional approval from the FERC was received in 2001. As proposed, TransConnect would be an independent, jointly owned, for-profit transmission company that will participate in RTO West and which could own or lease the high-voltage transmission facilities currently held by PGE and its other participants. 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.

Decisions to move forward with 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 (NW Natural), 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 electric power restructuring law, related regulations, and PGE's tariff. For additional information, see "Regulation and Competition" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operations".

Wholesale Competition and Marketing

Competition has transformed the electric utility industry at the wholesale level. The Energy Policy Act, passed in 1992, opened wholesale competition to energy brokers, independent power producers, and power marketers, and provided 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, requiring investor-owned utilities to allow others access to their transmission systems for wholesale power sales. This access must be provided at the same price and terms the utilities would apply to their own wholesale customers. It also requires reciprocity from municipals, cooperatives, and federal power marketers receiving service under the tariff and allows public utilities to recover stranded costs in accordance with the terms, conditions, and procedures set forth in the order.

The Company'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.

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 take advantage of price movements in electricity, natural gas, and crude oil.

Public Ownership Initiatives

In addition to the potential loss of revenues from those commercial and industrial customers that may choose to purchase energy directly from competing energy suppliers, there is also 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 examined by ratepayer activists and by certain local governments. 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 electric power 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 the Company's cost of power and its ability to economically displace more expensive thermal generation and spot market power purchases. In the last half of 2000 and first half of 2001, both the cost and availability of power were adversely affected by a reduction in the availability of surplus generation and weather conditions in California and the Southwest that resulted in high demand. In addition, higher natural gas prices and very poor Northwest hydro conditions (accentuated by fish protection spill requirements) further resulted in increased costs and reduced supply. From mid-2001 through the end of 2002, however, additional generation from both new plants and from those returning to service, moderating weather conditions, near-average hydro conditions, additional natural gas supplies, federal price mitigation, and a reduction in demand from both a significant downturn in Oregon's economy and conservation efforts have resulted in significantly lower market prices for both electricity and natural gas. These events have affected the balance of market supply and demand, and several independent power producers have delayed or cancelled plans for new generating plants.

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 1,945 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. For further information, see "Hydro Relicensing" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operations".

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.

On January 1, 2002, PGE sold a 33.33% undivided interest in its 450-MW Pelton Round Butte hydroelectric project to the Confederated Tribes of the Warm Springs Reservation of Oregon (Tribes). PGE has entered into contracts to purchase the Tribes' share of the power from the project for approximately five years, beginning January 2002. For further information, see Note 15, Sale of Pelton Round Butte Hydroelectric Project, in the Notes to Financial Statements.

In early 2001, PGE filed a "Notice of Intent" with Oregon's EFSC to build the Port Westward Generating Project, a new 650-MW gas turbine plant adjacent to the Beaver plant site. An air contamination discharge permit application has been approved, with a site certificate issued on November 8, 2002. All other required permits have either been obtained or are anticipated in the first half of 2003. PGE has not made a decision whether to develop this project at this time.

Assuming OPUC acknowledgement of PGE's Integrated Resource Plan, the Company anticipates issuance of a request for proposals (RFP) to acquire energy and capacity resources. The Company will continue to evaluate its options with regard to the construction of Port Westward (as well as other additional generation), considering the results of the RFP process, changes in economic conditions and resultant demand, and the effect of restructuring legislation that allows large customers to purchase power directly from electricity service suppliers. Further decisions regarding the Port Westward project are subject to both of these processes as well as required corporate approvals.

Purchased Power

PGE supplements its own generation with long-term and short-term contracts as needed to meet its retail load requirements. Under the provisions of state electricity restructuring legislation, the Company remains obligated to serve all of its customers. Under terms of a separate tariff schedule, certain non-residential customers may provide the Company notice 12 months prior to the start of a calendar year that they do not want PGE to include their loads in Company power purchases for the noticed year. Customers providing such notice may either obtain their power supply directly from an electricity service supplier or they may purchase power from PGE at then prevailing market rates (with price terms of one day to one year in length) for delivery in the noticed year. These customers are also required by the tariff to provide a year's advance notice should they choose to return to PGE for cost of service rates for a subsequent calendar year. For further information, see "Regulation and Competition" ("State") in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operations".

PGE has long-term power contracts with four hydroelectric projects on the mid-Columbia River, which provide approximately 652 MW of firm capacity. PGE also has firm contracts, ranging from one to twenty-six years, to purchase 828 MW of power from BPA, other Pacific Northwest utilities, and the Tribes. In addition, PGE has an exchange contract with a summer-peaking Southwest 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 145 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 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 2012, assuming the timely completion of planned new generation.

PGE's peak load in 2002 was 3,408 MW, reached on August 13th; this exceeded the Company's previous summer peak consumption of 3,341 MW in July 1998. Approximately 43% of the Company's 2002 peak load was met with short-term purchases. At December 31, 2002, PGE's total firm resource capacity, including short-term purchase agreements, was approximately 4,434 MW (net of short-term sales agreements of 3,927 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 given rise to 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. While long-term recovery plans for these species may include major operational changes to the region's hydroelectric projects, including PGE's, the impacts to date have been minimal. The biggest change has been modifying the timing of releases of water stored behind the dams in the upper part of the Columbia 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 hydroelectric relicensing efforts, in combination with endangered species consultations among the FERC, National Marine Fisheries Service (NMFS) and the United States Fish and Wildlife Service (USFWS), address issues associated with the protection of fish runs on those rivers where PGE operates, including authorization of "take" of listed species. The agencies have completed an ESA consultation on the Deschutes River, the location of the Company's Pelton Round Butte Project, that will be in effect until a new license is granted by the FERC; no significant operational changes to the project have been indicated. The Company awaits conclusion by the federal agencies of consultation with respect to its hydroelectric project on the Sandy River. The Company currently is supporting the federal agencies' ESA consultation activities regarding the Company's projects on the Clackamas and Willamette rivers, with minor operational changes implemented in February 2003 on the Clackamas and planned for 2004 on the Willamette. Completion by the FERC, NMFS, and USFWS of ESA consultation 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

Fuel supply contracts are negotiated to support annual planned plant operations. Flexibility in contract terms allows for the most economic dispatch of PGE's thermal resources in conjunction with the current 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 2003. 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 contracts with the Burlington Northern Santa Fe and Union Pacific Railroads. Coal purchases in 2002, totaling about 2.1 million tons, contained approximately 0.4% 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 provided under contract with Western Energy Company, a wholly owned subsidiary of Westmoreland Mining LLC. The contract provides for delivered 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 utilizes long-term, short-term, and spot market purchases to secure transportation capacity and gas supplies sufficient to fuel plant operations. PGE re-markets natural gas and transportation capacity in excess of its needs.

Beaver

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. Firm gas supplies for Beaver, based on anticipated operation of the plant, are purchased at fixed prices for 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. PGE believes that sufficient market supplies of gas are available to fully meet requirements of the plant in 2003 and beyond.

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 purchased at fixed prices for up to 24 months in advance. PGE believes that sufficient market supplies of gas are available to fully meet requirements of the plant in 2003 and beyond.

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 19-day supply of oil at the plant site at December 31, 2002.

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 Note 10, Legal and Environmental Matters, in the Notes to Financial Statements.

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 are also charged with monitoring and administering certain portions of the Act and are required to 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 emission 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. In addition, current emission allowances are sufficient to operate Colstrip, which utilizes wet scrubbers. If necessary, PGE intends to acquire sufficient additional allowances in order to meet excess capacity needs. 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, 2002 (*)	
Wholly Owned:				
Faraday	Clackamas River	Hydro	48	
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	529	
Coyote Springs	Boardman, OR	Gas/Oil	245	
Jointly Owned:				PGE Interest
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	227	66.67%
Total			1,945	
(*) PGE ownership share.				

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 five of the plants. Licenses for the Sullivan and Bull Run projects expire in 2004 and licenses for all projects on the Clackamas River expire in 2006. 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 FERC requires that a notice of intent to relicense hydroelectric projects be filed approximately five years prior to license expiration. The Company has filed notice to relicense and is actively pursuing renewal of licenses for all of its hydroelectric generating plants except Bull Run, which will not be relicensed. For further information, see "Hydro Relicensing" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operations".

On January 1, 2002, PGE sold a 33.33% undivided interest in its Pelton Round Butte hydroelectric project to the Tribes. For further information, see Note 15, Sale of Pelton Round Butte Hydroelectric Project, in the Notes to Financial Statements.

The rated generating capability at Beaver increased 5 MW based upon revised measurements of the plant's performance in 2002. The generating capability at Faraday increased 4 MW in 2002 due to turbine replacement and rehabilitation.

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

Leased Properties

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

Item 3. Legal Proceedings

Citizens' Utility Board of Oregon v. Public Utility Commission of Oregon and Utility Reform Project and Colleen O'Neill v. Public Utility Commission of Oregon

, Marion County Oregon Circuit Court, the Court of Appeals of the State of Oregon, the Oregon Supreme Court

Following the closing of 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 regarding recovery of the Trojan investment and decommissioning costs. In August 1993, the OPUC issued the 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, 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. 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 Oregon Court of Appeals 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 decision relating to PGE's recovery of its undepreciated investment in Trojan.

In June 1999, Oregon's governor signed into law Oregon House Bill 3220 authorizing the OPUC to allow recovery of a return on the undepreciated investment in utility property that the utility retires from service. The law retroactively affirmed the OPUC's authority to allow PGE's recovery of a return on its undepreciated investment in Trojan.

Relying on the new legislation, in July 1999, PGE requested the Oregon Supreme Court to vacate the 1998 ruling of the Oregon Court of Appeals denying a return on its undepreciated investment in Trojan and affirm the validity of the OPUC's order allowing such recovery. The URP and CUB opposed the request on the ground that an effort was underway to gather sufficient signatures to place on the ballot a referendum to negate the new legislation. Sufficient signatures were gathered, and in the November 7, 2000 election, the voters approved the referendum rejecting House Bill 3220.

In September 2000, PGE, CUB, and the OPUC Staff settled proceedings related to PGE's recovery of its investment in the Trojan plant (Settlement). Under the agreements, CUB agreed to withdraw from the litigation and support the settlement as the means to resolve the Trojan litigation. 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. Following the Settlement, PGE requested the Oregon Supreme Court to hold in abeyance the PGE and URP Petitions for Review of the 1998 Court of Appeals decision, pending resolution of URP's complaint 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, 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 July 1, 2002, PGE filed a notice and motion to dismiss and vacate with the Oregon Supreme Court seeking to dismiss the pending review of the 1998 decision of the Oregon Court of Appeals and to vacate that decision. On November 19, 2002, the Oregon Supreme Court denied PGE's motion to dismiss and vacate and also 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 remand to the OPUC became effective.

On December 31, 2002, PGE was granted intervention in the Marion County proceeding filed by URP challenging the March 2002 Settlement Order approving PGE's application of the accounting and ratemaking elements of the Settlement.

On January 17, 2003, URP filed a Petition to Reconsider and Motion to Recall Appellate Judgment and Modify with the Court of Appeals. This pleading requests the Court of Appeals to remand the matter to the Marion County Circuit Court and not to the OPUC as required in the Court of Appeal's 1998 ruling. PGE and the OPUC filed in opposition to this request. A decision from the Court is pending.

For further information, see Note 10, Legal and Environmental Matters, in the Notes to Financial Statements.

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 actions suits were filed 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. PGE intends to vigorously defend these cases.

For further information, see Note 10, Legal and Environmental Matters, in the Notes to Financial Statements.

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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 but the order was not immediately implemented. The Duke and Reliant Parties filed an appeal to the United States Ninth Circuit Court of Appeals and applied to the District Court for a stay of the remand to the California state court. On January 24, 2003, the District Court denied the application for a stay and deferred certain motions for reconsideration. 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 and set a briefing schedule that will not be completed until mid-September 2003. 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. The complaint seeks fines and penalties under the California Business and Professions Code for each sale from 1998 through 2001 above a "capped price" or a reasonable price and for each alleged regulatory violation. No specific damage claim is stated. On July 10, 2002, PGE filed a Notice of Removal to the U.S. District Court. On July 17, 2002, PGE filed a Motion to Dismiss on preemption grounds with the U.S. District Court.

Following PGE's filing to remove the case to the U.S. District Court, the Attorney General filed a motion with U.S. District Court to remand the case to the state court. The motion has been denied. The Attorney General filed an appeal to the Ninth Circuit Court of Appeals of the denial of the motion to remand, and a motion to stay with the U.S. District Court. The U.S. District Court, finding the appeal to the Court of Appeals frivolous, denied the motion to stay the case. The motion to dismiss filed by PGE was argued on September 26, 2002 and is currently under advisement by the U.S. District Court.

Symonds v. Dynegy, Inc. et al

. United States District Court Western District of Washington. Case No. CV02-2522

On December 20, 2002, a class action suit on behalf of consumers in the State of Washington was filed against participants in the Pacific Northwest electric power markets, including PGE. The suit alleges violation of the Washington Consumer Protection Act, fraud by concealment, and negligence. The relief sought includes treble damages, attorney fees, and injunctive relief to prohibit the unlawful practices alleged. No monetary amount is specified. Plaintiff has agreed to extend the time for PGE to respond until after April 2, 2003.

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, 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. PGE has 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. The IBEW filed an answer and counterclaim that the issue is arbitrable, and PGE filed a reply that denied the counterclaim and raised four affirmative defenses. The Circuit Court has set a trial date of May 22, 2003. See Note 10, Legal and Environmental Matters, in the Notes to Financial Statements for further information.

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

None.

Part II

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

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

Quarter	2002	2001
1	$ -	$ 20
2	-	20
3	*	-

4 - -

* PGE declared a non-cash dividend of $27 million in July 2002. For further information, see Note 12, 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 facilities prohibit the payment of common stock dividends to Enron (excluding the non-cash dividend described above). For further information, see "Dividends" in the "Liquidity and Capital Resources" section of Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 4, Common and Preferred Stock, in the Notes to Financial Statements.

Item 6. Selected Financial Data

	For the Years Ended December 31				
	2002	2001	2000	1999	1998
			(In Millions)		
Operating Revenues (a)	$1,855	$2,420	$1,887	$1,378	$1,176
Net Operating Income	135	134	206	190	200
Net Income	66	34	141	128	137
Total Assets	3,250	3,474	3,452	3,167	3,162
Long-Term Obligations (b)	1,046	972	880	763	876

(a) Amounts for 2000 and 2001 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. For further information, see Note 1, Summary of Significant Accounting Policies, in the Notes to Financial Statements.

(b) Includes long-term debt and preferred stock subject to mandatory redemption requirements. Long-term capital lease obligation of $1 million is included in 1998; there were no capital lease obligations from 1999-2002.

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

Results of Operations

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	2002		2001		Increase/(Decrease)		
(In Millions)					Amount		%
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 replaced 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. For further information regarding trading activities, see Note 8, Price Risk Management, in the Notes to Financial Statements.

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 was 60% of last year (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 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 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) for the last two years (excludes energy trading activities). Average variable power costs indicated exclude the effect of credits to purchased power and fuel costs related to PGE's power cost 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. Based on ratemaking history, the Company believes that this deferred tax relates to the flow through of tax benefits to customers in periods 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. Management does not believe the related charge is significant to 2002 results of operations. 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 and its subsidiaries. The Company also reversed a $3 million credit reserve established in 2001 related to receivables from Enron. (For additional information, see Note 12, Related Party Transactions, in the Notes to Financial Statements). 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 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.

<u>2001 Compared to 2000</u>

PGE's net income in 2001 was $34 million compared to $141 million in 2000. Significantly higher power costs and lower energy loads in 2001, partially offset by a general rate increase that became effective at the beginning of the fourth quarter, contributed to an approximate 35% decrease in net operating income. Results for 2001 also include 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, the Company recorded after tax provisions of approximately $13 million in 2001 related to amounts receivable for energy sales in the California wholesale market, a franchise fee audit, and costs associated with the cancellation of a proposed gas turbine generation project.

The following table summarizes Operating Revenues and Energy Sales for 2001 and 2000:

Operating Revenues	2001	2000	Increase/(Decrease)	
(In Millions)			Amount	%
Retail	$1,090	$1,058	$ 32	3%
Wholesale (Non-Trading)	1,313	774	539	70%
Other Operating Revenues:				
Trading activities - net	(11)	30	(41)	*

Other	28	25	3	12%
Total Operating Revenues	$2,420	$1,887	$533	28%
Energy Sales				
(In Thousands of MWhs)				
Retail	19,040	19,872	(832)	(4%)
Wholesale (Non-Trading)	9,764	12,858	(3,094)	(24%)
Trading Activities	3,862	5,690	(1,828)	(32%)
Total Energy Sales	32,666	38,420	(5,754)	(15%)
			(*not meaningful)	

The increase in total Operating Revenues in 2001 was due primarily to higher prices for wholesale energy sales. The increase in wholesale (non-trading) revenues was attributable to prices that more than doubled due to the combined effect of higher natural gas prices, below normal hydro conditions, and market forces within the region. Wholesale sales volume decreased 24% as power activities slowed due to uncertainty and volatility in energy markets during the year.

The increase in retail revenues was due to a general rate increase that became effective October 1, 2001. Retail energy sales decreased 4% as a slowing economy, mild weather, conservation, and PGE's Demand Buyback program more than offset an approximate 11,000 (1.5%) increase in total customers from the end of 2000. A total of $42 million in retail revenues was deferred to 2002 to reflect amounts collected in excess of net variable power costs.

Other operating revenues decreased $38 million, primarily as the result of losses incurred in the Company's electricity and fuel trading activities. In 2001, PGE sustained losses in its trading activities as the Company sold higher-cost wholesale purchases at prevailing market prices that had moderated significantly from the prior year. Conversely, in 2000 PGE achieved gains on such activities as the Company's cost of power and fuel sold in the wholesale market was significantly exceeded by prevailing market prices. For further information regarding trading activities, see Note 8, Price Risk Management, in the Notes to Financial Statements.

Purchased power and fuel costs increased $639 million (58%), as PGE's average variable power cost increased 91% from 2000. During the fourth quarter of 2000 and through the first quarter of 2001, PGE entered into electricity and natural gas forward contracts for the last half of 2001 at forward prices reflecting the higher prevailing market prices. Western wholesale power prices moderated significantly in the last half of 2001 due to the combined effects of mild weather, additional generation capacity in the West, increased natural gas supplies, lower retail loads, and conservation. As prices declined, PGE was unable to sell excess wholesale power at prices covering the cost of such power, resulting in historically high net variable power costs in the last half of 2001. Conversely, in 2000, PGE achieved significantly lower net variable power costs in the last half of the year as the Company sold on the wholesale market excess power purchases, made in anticipation of higher retail demand, at prices significantly higher than cost. The Company also recorded additional provisions in 2001 related to the collectibility of receivable balances associated with certain energy sales in the California wholesale market. For further information, see Note 13, Receivables - California Wholesale Market, in the Notes to Financial Statements.

Partially offsetting the effect of increased prices was a 12% decrease in total system load, as both wholesale and retail energy sales decreased from 2000. PGE's Demand Buyback program, by which certain large customers voluntarily reduced their electricity usage during certain peak periods during the first nine months of 2001, reduced manufacturing sector sales by 6.4% and partially offset the Company's increased cost of power. In addition, Purchased power and fuel costs in 2001 include an approximate $84 million credit related to the Company's power cost mechanism, in which a portion of net variable power costs exceeding a baseline amount were deferred for future recovery from customers. (See "Power Cost Mechanisms" in the Financial and Operating Outlook section for further information).

Company generation increased 8% in 2001, with a 15% increase in combustion turbine and coal generation partially offset by reduced hydro production. Total generation met approximately 61% of PGE's retail load during 2001, compared to 54% in 2000.

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 indicated exclude the effect of credits to purchased power and fuel costs related to PGE's power cost mechanisms, as discussed above.

Megawatt-Hours/Variable Power Costs

	Megawatt-Hours (thousands)		Average Variable Power Cost (Mills/KWh)	
	2001	2000	2001	2000
Generation	12,331	11,430	18.9	14.5
Term Purchases	16,098	20,143	83.4	30.2
Spot Purchases	1,626	2,419	112.2	119.6
Total Send-Out	30,055	33,992	60.0*	32.3*

(* includes wheeling costs)

Operating expenses (excluding purchased power and fuel, depreciation and amortization, and taxes) increased $16 million (6%). Increased energy efficiency expenditures and customer service and support activities were the primary causes of the increase. (Energy efficiency expenditures were deferred and amortized prior to October 1, 2000, but in 2001 were expensed and recovered by additional revenues). Partially offsetting these increases were lower employee benefit costs and the effect of a nonrecurring 2000 provision made against deferred costs related to the proposed sale of the Company's 20% interest in Units 3 and 4 of the Colstrip power plant. (The sale was denied by the OPUC and the Company was granted rate recovery of a portion of such costs in its 2001 general rate proceeding).

Depreciation and amortization expense increased $6 million (4%), due primarily to the effect of normal capital additions and to the removal of certain regulatory liabilities from the balance sheet as part of 2000's Trojan settlement agreement. (For additional information, see Note 10, Legal and Environmental Matters, in the Notes to Financial Statements). Partially offsetting these increases were decreases in regulatory amortization, including that related to the Company's SAVE program promoting energy efficiency.

Income taxes decreased $56 million (60%) primarily due to lower taxable income, $5 million in adjustments to deferred income taxes, and the utilization of $2 million in state energy tax credits.

Other income decreased $85 million primarily due to a $79 million provision for uncollectible accounts receivable from Enron and affiliated companies recorded in December 2001 due to uncertainties surrounding Enron's bankruptcy proceedings. (For additional information, see Note 12, Related Party Transactions, in the Notes to Financial Statements). In addition, in 2000, PGE received $15 million related to the termination of its membership in Nuclear Electric Insurance Limited (NEIL) and also wrote off $5 million of its remaining investment in the Trojan plant as part of a settlement agreement. In 2001, PGE incurred a $5 million loss in the value of trust owned life insurance (compared to a $1 million loss in 2000). These were partially offset in 2001 by a $7 million increase in interest income, including $6 million related to the Enron merger credit and SCE contract termination, both of which were offset in the Trojan settlement agreement, with related interest reflected in income. Taxes on other income provided a $39 million benefit resulting from the decrease in taxable income.

Interest charges remained the same for both 2000 and 2001. An increase in interest on long-term debt and other, due to both interest on wholesale trading deposits and to the March 2000 issuance of $150 million in unsecured notes, was offset by reduced interest on a lower average level of commercial paper outstanding during 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 depreciation and amortization of utility plant charges which are recovered in customer revenues but require no current period cash outlay. Changes in accounts receivable and accounts payable can also be significant contributors or users of cash.

Cash provided by operating activities totaled $298 million in 2002 compared to $67 million of cash used in such activities in 2001. The increase was due primarily to a $312 million reduction in cash collateral deposit requirements with wholesale customers related to the settlement of certain energy contracts, and to increased receipts from wholesale and retail energy sales.

Cash from operations and remaining proceeds from the October 2002 issuance of long-term debt and early retirement of first mortgage bonds (described below) were invested primarily in government money market funds at December 31, 2002.

Investing Activities

consist primarily of improvements to PGE's distribution, transmission, and generation facilities. A $38 million reduction in capital expenditures in 2002 is primarily attributable to reduced expenditures for generation construction and intangible plant, consisting primarily of computer software development costs. Capital expenditures in 2001 included $14 million related to construction of a new 24.5 megawatt combustion turbine unit at the Company's Beaver plant site, as well as certain large transmission substation and production plant improvements. Capital expenditures are expected to approximate $180 million in 2003, with the majority of expenditures expected to consist of improvements to, and expansion of, PGE's distribution system to support both new and existing customers within the Company's service territory.

Financing Activities

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

Short-term -

During 2002, PGE repaid $174 million of short-term borrowings. Cash collateral deposits returned by wholesale customers and cash from operations were used to repay $129 million in commercial paper, with proceeds from the issuance of long-term debt used to retire $45 million of short-term bank loans.

Although PGE has traditionally utilized commercial paper borrowings in meeting its day-to-day cash requirements, the Company has been unable to access the commercial paper market due to ratings reductions by credit rating agencies.

In June 2002, PGE entered into a new $72 million 364-day revolving credit facility with a group of commercial banks, replacing a $200 million credit facility that expired in June 2002. Under this facility, PGE has the option to use letters of credit, in addition to borrowings, totaling up to the $72 million. The Company also has a three-year $150 million revolving credit facility that expires in July 2003. Together, the two credit facilities provide available liquidity to PGE of $222 million.

Each facility contains rating sensitive pricing, though neither facility contains rating triggers that would cause acceleration, default, or puts. The facilities have material adverse change clauses and covenants that limit consolidated indebtedness, as such term is defined in the facilities, to 60% of total capitalization, and that require a minimum 2.25:1 ratio of earnings before interest and taxes (EBIT) to consolidated interest expense. PGE's indebtedness to total capitalization and interest coverage ratios at December 31, 2002 were 45.5% and 2.67:1, respectively. Both facilities are secured by First Mortgage Bonds. Borrowings under these credit facilities, along with cash provided by operations, have replaced the use of commercial paper in meeting PGE's day-to-day cash requirements.

PGE is evaluating alternatives for the replacement of its credit lines expiring in June and July 2003, including the issuance of First Mortgage Bonds and/or new revolving credit facilities. As of December 31, 2002, the Company has sufficient capacity under its Indenture of Mortgage to issue additional First Mortgage Bonds for this purpose.

For additional information, see Note 5, Credit Facilities and Debt, in the Notes to Financial Statements.

Long-term -

In October 2002, PGE issued $250 million in First Mortgage Bonds, consisting of $150 million of 8 1/8% bonds maturing February 2010 and $100 million of 5.6675% bonds maturing October 2012. The Company purchased a policy insuring the principal and interest payments on the latter issue, which adds approximately 1.5% to annual interest costs. Both bond issues were private placements, with net proceeds from both issues used to reduce short-term debt, refinance current maturities of long-term debt, and for other general corporate purposes. In October 2002, PGE utilized a portion of the proceeds of these two bond issues for the early retirement of $150 million in First Mortgage Bonds due in December 2002. Also in 2002, PGE retired $15 million in matured First Mortgage Bonds and $9 million of conservation bonds and other long-term debt, and retired $2 million of preferred stock.

In 2001, PGE issued $150 million of variable rate First Mortgage Bonds, which were used to reduce commercial paper borrowings and bank loans under the Company's revolving credit facilities. The bonds were retired early in October 2002, as described above. In addition, PGE repaid $58 million in matured First Mortgage Bonds, pollution control bonds, and conservation bonds during 2001.

PGE has $49 million in long-term debt maturing in 2003, consisting of $40 million in First Mortgage Bonds that mature in August and $9 million of conservation bonds maturing throughout the year. The Company anticipates meeting these obligations through the sale of other long-term debt, the use of its existing credit facilities, or from cash from operations. In addition, PGE expects to re-market $142 million of tax-exempt pollution control bonds that will be put back to the Company in May 2003. If the bonds are not re-marketed, PGE anticipates using cash from operations and proceeds from the sale of other long-term debt to repurchase the bonds.

PGE currently plans to utilize letters of credit to provide funding assurance for certain future decommissioning activities at Trojan. 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 accounts. It is currently anticipated that such funding assurance, for an estimated initial amount of $25 million, will be required upon completion of the transfer of spent nuclear fuel to an on-site dry storage facility in late 2003. Such amount would decrease through late 2005, as radiological decommissioning is completed. The timing and amount of actual funding assurance requirements are subject to change. PGE does not expect that such obligation will have a material effect on its financing requirements.

The issuance of additional First Mortgage Bonds and preferred stock requires PGE to meet earnings coverage and security provisions set forth in the Articles of Incorporation and the Indenture securing the bonds. As of December 31, 2002, PGE has the capability to issue additional First Mortgage Bonds in amounts sufficient to meet its anticipated capital requirements.

Dividends -

In 2002, PGE paid $2 million in preferred stock dividends. In July 2002, upon approval of the Company's board of directors, PGE made a non-cash dividend of $27 million to Enron related to the transfer of a receivable balance due from PGH (for further information, see Note 12, Related Party Transactions, in the Notes to Financial Statements). No other common stock dividends were declared in 2002. In 2001, PGE paid $40 million in common stock dividends to Enron and $2 million in preferred stock dividends.

Management continues to evaluate the future declaration of common stock dividends in light of expected cash requirements and other considerations. PGE is restricted, without prior OPUC approval, from making dividend distributions to Enron that would reduce PGE's common equity capital below 48% of total capitalization (excluding short-term borrowings). In addition, the Company's revolving credit facilities prohibit the declaration or payment of dividends on PGE's capital stock except for regularly scheduled dividends on its preferred stock and the $27 million non-cash dividend to Enron described above.

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), with Fitch Ratings (Fitch) currently carrying a below investment grade rating on the Company. In their 2002 reviews of PGE ratings, credit agencies cited PGE's reduced financial flexibility resulting from its status as a subsidiary of an insolvent parent (Enron), a difficult capital market environment, and uncertainty regarding ongoing federal investigations into the Company's energy trading activities in the western U.S. power markets. Also cited in such reviews was the expectation that PGE would be sold, the significant credit enhancement and strengthened liquidity resulting from PGE's creation of a ring fence structure (described in the following paragraph), as well as the Company's fundamentally sound operations, healthy capitalization ratios, and levels of earnings and cash flows.

PGE 's current credit ratings are as follows:

	Moody's	S&P	Fitch2
First Mortgage Bonds	Baa2	BBB+	BB+
Senior unsecured debt	Baa3	BBB	BB-
Preferred stock	Ba2	BBB-	B
Commercial paper	Prime-3	A-2	Withdrawn
Outlook:	Negative	Developing	Ratings Watch Negative

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.

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, 2003, PGE had posted, in the form of letters of credit, $16 million of collateral. Based on the Company's non-trading and trading portfolio, estimates of current energy market prices, and the current level of collateral outstanding, as of January 31, 2003, the approximate amount of additional collateral that could be requested upon such a downgrade event is $36 million and decreases to approximately $29 million by year-end 2003. In addition to collateral calls, such a credit rating reduction would likely have an adverse effect on the terms and conditions of future long-term debt. In addition, any such rating reductions would increase interest rates on PGE's two revolving credit facilities, increasing the cost of funding its day-to-day working capital requirements.

PGE's ability to access the commercial paper market has been adversely affected by the May 2002 ratings reduction for commercial paper by Moody's and Fitch. Management believes that it has the ability to use its existing lines of credit, along with cash from operations, to provide the Company with sufficient liquidity to meet its day-to-day cash requirements.

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, it does believe 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 proceeding 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, 2002 (in millions):

	Payments Due											
												After
	Total		2003		2004		2005		2006		2007		2007
Long-Term Debt	$1,018		$ 191		$ 55		$ 28		$ 9		$ 50		$ 685
Preferred Stock	28		1		1		1		1		24		-
Operating Leases	174		10		10		8		6		7		133
Purchase Commitments	37		31		2		1		1		1		1
Purchased Power and Fuel:													

Electricity Purchases	931	540	137	120	101	5	28
Capacity Contracts	275	19	19	19	19	19	180
Natural Gas Agreements	208	63	23	15	14	14	79
Public Utility Districts	88	9	8	7	6	6	52
Coal Agreements	12	12	-	-	-	-	-
Trojan:							
Decontamination and							
Decommissioning Fund	4	1	1	1	1	-	-
Decommissioning Funding							
Assurance (*)	51	28	19	4	-	-	-
Total Contractual							
Cash Obligations	$2,826	$ 905	$ 275	$ 204	$ 158	$ 126	$1,158

(*) Indicated amounts represent average amount of required collateral during year. See Note 11, Trojan Nuclear Plant, in the Notes to Financial Statements for further information.

<u>Other Financial Obligations and Guarantees</u>

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. For further information, see "Purchased Power" in Note 7, Commitments, in the Notes to Financial Statements.

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 2003, is approximately $250 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

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 are in compliance with the requirements and ratemaking practices of regulatory authorities having jurisdiction. For certain transactions where revenues, costs, and gains would otherwise be recorded in income under GAAP, they are deferred for future ratemaking treatment under SFAS No. 71, Accounting for the Effects of Certain Types of Regulation, to reflect the effects of regulation. (These assets and liabilities, titled Unamortized regulatory assets and Unamortized regulatory liabilities on the Consolidated Balance Sheets, total $544 million and $16 million, respectively, at December 31, 2002). 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.

The preparation of the financial statements requires management to use estimates and make judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related contingency disclosures. PGE evaluates its estimates on a continuing basis and makes revisions based upon historical experience, new information, and other assumptions that are reasonable under the circumstances. Actual results could differ from such estimates.

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; gain contingencies are recognized upon realization and are disclosed when material. Reserves established reflect management's assessment of inherent risks, credit worthiness, and complexities involved in the collection process.

Revenues are recognized when customers are billed for electricity sold. In addition, unbilled revenues are recorded for services provided to retail customers from the meter read date to month-end. In certain situations, PGE defers the recognition of revenues until the period in which costs are incurred, in accordance with the provisions of SFAS No. 71.

PGE engages in price risk management activities for both non-trading and trading purposes, utilizing derivative instruments such as electricity forward and option, and natural gas forward, swap and futures contracts. Derivative contracts entered into for non-trading purposes are anticipated to serve the Company's regulated retail load. Non-trading derivative contracts are utilized to protect the Company against variability in expected future cash flows due to associated price risk and to manage power and fuel costs for retail customers. PGE enters into derivative contracts for trading purposes to take advantage of price movements in electricity, natural gas, and crude oil; 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 and SFAS No. 138. (Prior to 2001, trading contracts were recorded at fair value pursuant to Emerging Issues Task Force (EITF) Issue 98-10, Accounting for Energy Trading and Risk Management Activities). For non-trading activities, certain derivative instruments are recorded at fair value on the balance sheet, with changes in fair value reflected as 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 the changes in fair value in current earnings.

Accounts receivable are evaluated for collectibility based upon past experience and the best available information. Management continues to assess PGE's exposure to all accounts receivable balances and establishes an appropriate allowance for doubtful accounts for amounts due.

For additional information, see Note 1, Summary of Significant Accounting Policies, in the Notes to Financial Statements.

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 OPUC regulation. Most affiliated interest transactions are made under a Master Service Agreement (MSA) approved by the Commission. Any transactions not covered by the MSA must be separately approved by the Commission. 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. In addition to affiliated services, PGE provides transmission services under an existing contract for an Enron subsidiary, which is part of Enron's bankruptcy proceedings. The ultimate disposition of the intercompany receivable and payable balances with Enron and its subsidiaries at December 31, 2002 is uncertain due to Enron's bankruptcy proceedings. The Company has recorded provisions against certain receivable balances due from Enron companies in bankruptcy. For further information, see Note 12, Related Party Transactions, and Note 16, Enron Bankruptcy, in the Notes to Financial Statements.

Trading Activities Accounted for at Fair Value

PGE trading activities utilize electricity forward and option contracts, natural gas forward, swap and futures contracts, and crude oil futures contracts to take advantage of price movements in electricity, natural gas, and crude oil. Valuation of these instruments reflects management's best estimates of market prices, including closing NYMEX and over-the-counter quotations, time value, and volatility factors underlying the commitments. At December 31, 2002, 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 2002 and 2001, as well as the source of the fair value of the unrealized loss at December 31, 2002 and unrealized gain at December 31, 2001 (in millions):

		Unrealized Gain (Loss)		
		2002		2001
Unrealized gain of contracts as of January 1		$ 3		$ 13
Less contracts realized during year:				
	Contracts entered in prior years	(4)		(6)

	Contracts entered in current year	1	7
Change in fair value attributable to market changes:			
	Contracts entered in prior years	1	(7)
	Contracts entered in current year	(2)	(4)
Unrealized gain (loss) of contracts as of December 31		$ (1)	$ 3

	Unrealized Loss of Trading Contracts at Year End			
Source of Fair Value	Maturity	Maturity	Maturity over	Total Unrealized
At December 31, 2002	0 - 6 mos.	6 - 12 mos.	1 yr.	Loss
Prices actively quoted	$ -	$ (1)	$ -	$ (1)
Prices provided by other external sources	-	-	-	-
Prices based on models and other valuation methods	-	-	-	-

	Unrealized Gain of Trading Contracts at Year End			
Source of Fair Value	Maturity	Maturity	Maturity over	Total Unrealized
At December 31, 2001	0 - 6 mos.	6 - 12 mos.	1 yr.	Gain
Prices actively quoted	$ 2	$ 1	$ -	$ 3
Prices provided by other external sources	-	-	-	-
Prices based on models and other valuation methods	-	-	-	-

Financial and Operating Outlook

Enron Bankruptcy

Commencing in December 2001, Enron and certain of its subsidiaries filed for bankruptcy under Chapter 11 of the federal Bankruptcy Code. Neither PGE nor numerous other Enron subsidiaries, including subsidiaries owning gas pipelines and related facilities, are included in the bankruptcy. 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. In March 2002, Enron, substantially all of its subsidiaries and several former officers were suspended by the General Services Administration from contracting with the federal government.

Although PGE is not included in the Enron bankruptcy, it has been affected. The Company has been included in requests for documents related to Congressional and regulatory investigations, with which it is fully cooperating. PGE was also included among those Enron subsidiaries suspended from contracting with the federal government. PGE believes it does not merit suspension and has initiated the process to have the suspension removed. No federal, state, or local governmental entity has ceased to transact business with PGE, and the BPA has stated that the suspension does not affect its sales and purchases of electricity with the Company. Management believes the suspension will not have a material adverse effect on PGE business and operations.

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 -** As described in Note 12, Related Party Transactions, in the Notes to Financial Statements, PGE is owed approximately $81 million (including accrued interest) by Enron at December 31, 2002 (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 has established a reserve for the entire amount of this receivable, of which $74 million 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 $73 million for the Merger Receivable balance as of December 2, 2001, the date of Enron's bankruptcy filing. In addition, due to uncertainties associated with other receivable balances from Enron subsidiary companies which are part of the bankruptcy proceedings, a credit reserve has been established for the entire net $2 million remaining balance of such receivables at December 31, 2002.

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

Pension Plans

Funding Status

The pension plan for the employees of PGE (the PGE Plan) is separate from the Enron Corp. Cash Balance Plan (the Enron Plan). Although at December 31, 2002 the total fair value of PGE Plan assets was $16 million lower than the projected benefit obligation on a SFAS No. 87 (Employers' Accounting for Pensions) basis, the PGE Plan remains over-funded on an accumulated benefit obligation basis by about $30 million. Enron's management has informed PGE that, as of December 31, 2001 (the most recent date for which information is available), the assets of the Enron Plan were less than the present value of all accrued benefits by approximately $90 million on a SFAS No. 87 basis and approximately $120 million on a plan termination basis. Further, Enron's management has informed PGE that the PBGC has claims in the Enron bankruptcy cases. The claims are duplicative in nature, representing unliquidated claims for PBGC insurance premiums (the "Premium Claims") and unliquidated claims for due but unpaid minimum funding contributions (the "Contribution Claims") under the Internal Revenue Code of 1986, as amended (the "Tax Code") 29 U.S.C. Section 412(a) and 1082 and claims for unfunded benefit liabilities (the "UBL Claims"). Enron and the relevant sponsors of the defined benefit plans are current on their PBGC premiums and their contributions to the pension plans. Therefore, Enron has valued the Premium Claims and the Contribution Claims at $0. The total amount of the UBL Claims is $305.5 million (including $271 million for the Enron Plan, and $24.8 million for 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 provided no 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 management, PGE is a solvent entity that does not meet the financial distress test. Consequently, 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. Management believes that any lien asserted by the PBGC would be subordinate to that lien.

Management of PGE has been informed by management of Enron that on November 15, 2002, Enron informed its employees that it is taking steps to terminate the Enron Plan. As an initial step in terminating the Enron Plan, Enron amended the Enron Plan to cease monthly accruals effective January 1, 2003, so that only interest credits would accrue after that date. Enron also informed its employees that it intends to seek the approval of its Unsecured Creditors' Committee and the U.S. Bankruptcy Court to fully fund and then terminate the Enron Plan. Approval to terminate the Enron Plan also will be requested from the PBGC and the Internal Revenue Service. Enron informed its employees that, if approved, the termination process could take 12 months or longer.

PGE management believes that the proposal to fully fund the Enron Plan and terminate it in a standard termination, if approved and consummated, should eliminate any need for the PBGC to attempt to collect from PGE any liability related to the termination of the Enron Plan. There can be no assurance at this time that the funding and termination will be approved by the Unsecured Creditors' Committee or the Bankruptcy Court or that, upon such approval, Enron will have the ability to obtain funding on acceptable terms.

If 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 management understands that Enron has made all required contributions to date and the next contribution is not due until July 15, 2003. PGE does not know if Enron will make contributions as they become due. 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

Under COBRA, retirees of a bankrupt employer who lose coverage under a group health plan of the employer as a result of certain bankruptcy proceedings are entitled to elect continuation of health coverage in a group health plan maintained by the bankrupt employer or a member of its controlled group. PGE management understands, based on discussion with Enron management, that Enron provides a plan for health insurance for certain retirees, and that the actuarial liability for such coverage amounted to approximately $70 million at December 31, 2001 (the most recent date for which information is available). Management further understands that to meet its obligation, as of December

31, 2001, Enron had set aside approximately $34 million of assets in a VEBA trust that may be protected under ERISA from Enron's creditors, leaving an unfunded liability of approximately $36 million at December 31, 2001.

In the event that Enron terminates its retiree group health plan, the retirees must be provided the opportunity to purchase continuing coverage from Enron's group health plan, if any, or the appropriate group health plan of another member of the controlled group. Neither Enron nor any member of the controlled group would be required to fully fund the benefit or create new plans to provide coverage, and retirees would not be entitled to choose from which plan 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 continue 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 coverage under COBRA. Retirees will be able to shop for coverage from third party sources and determine which is the least expensive coverage.

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 discussion 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. 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, 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. Management believes that the additional cost to PGE to provide 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 Portland General Corporation. Based on discussions with Enron's management, PGE management understands that PGE ceased to be a member of Enron's consolidated group on May 7, 2001 and became a member of Enron's consolidated group once again on December 24, 2002. Simultaneously with PGE's rejoining the Enron consolidated group, 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'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 is currently auditing the consolidated returns for 1996-2001. Enron's consolidated tax return for 2001 was filed on September 13, 2002 and Enron expects this return and claims by the IRS, if any, to be included in the bankruptcy process, as described below.

B. For years 1996-1999, 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 loss, which will be carried back to tax year 2000, and is anticipated to result in a tax refund for taxes paid in 2000. The carryback of the 2001 loss to 2000 is expected to provide Enron and its subsidiaries substantial NOLs for any additional income tax liabilities that may result from the ongoing IRS audit for the periods in which PGE was a member of Enron's consolidated federal income tax returns. However, to the extent that such audit results in interest owing by the Enron consolidated group for periods after Enron filed its bankruptcy petition ("postpetition interest") or in penalties that would not have a statutory priority over general unsecured creditors, the IRS could seek to collect such amounts from consolidated group members not in bankruptcy, such as PGE. The last day that the IRS can file a proof of claim for prepetition taxes in the bankruptcy case, absent a court-approved extension of time, is March 31, 2003. It is anticipated that the IRS will file a proof of claim for periods through 2001 prior to that date. If there were additional tax liabilities claimed by the IRS, these would be satisfied by funds in the bankruptcy estate ahead of unsecured Enron creditors, but claims for postpetition interest would not be allowed, and claims for penalties would be treated on a par with the claims of general unsecured creditors.

Although Enron's management cannot predict with certainty the outcome of the IRS audit, based on the above, it believes it is unlikely at this time that any tax claims by the IRS would exceed the substantial NOLs available to the Enron consolidated tax returns. Claims for postpetition interest and claims for penalties, if any, could not be offset by these NOLs. If the IRS did seek payment and Enron did not pay, the IRS could look to one or more members of the consolidated group, including PGE. If the IRS did 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 obtain contributions from the other solvent members of the consolidated group, who are not debtors in the bankruptcy case. 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.

C. Enron's 2002 tax return has not yet been filed. As noted in paragraph B. above, Enron expects to have substantial NOLs from operations in years preceding 2002. Enron expects that, in addition to offsetting its income tax liabilities for years before 2002, these NOLs will be sufficient to fully offset Enron's regular and alternative minimum income tax liabilities for 2002 and its regular income tax liability for all subsequent periods through the date of consummation of its plan of reorganization.

PGE management cannot predict with certainty what impact Enron's bankruptcy 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 Portland General Corporation 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 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. PGE believes that in a bankruptcy, Enron would lose most, if not all control over PGE. It would become merely 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. As debtor in possession, PGE would owe fiduciary obligations to its creditors. It would be the creditors of PGE, not Enron or the creditors of Enron, that would form a creditors' committee with oversight over the activities of PGE management. PGE believes that any plan of reorganization would be devised by PGE management and subject to confirmation by the Bankruptcy Court after the vote of PGE's (not Enron's) 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 Bankruptcy Court after notice to PGE's creditors. 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 years of litigation and effectively preclude any transfer of stock, assets, or other funds from PGE to Enron or any other party. 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. See Note 4, Common and Preferred Stock, in the Notes to Financial Statements for further information.

Management cannot predict the ultimate outcome of the above matters due to the uncertainties surrounding Enron's bankruptcy. For additional information, see Note 16, Enron Bankruptcy, in the Notes to Financial Statements.

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. 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 May 3, 2002, Enron presented to its Unsecured Creditors' Committee a proposal under which certain of Enron's core energy assets, including PGE, would be separated from Enron's bankruptcy estate and operated prospectively as a new integrated power and pipeline company. If Enron's proposal were to be adopted, the inclusion of PGE in the new company would be subject to potential sale to a different buyer under a bankruptcy code Section 363 auction process, which would be supervised by the Bankruptcy Court. Enron's proposal has not been endorsed or approved by the Unsecured Creditors' Committee and is one of many options Enron may pursue.

On August 27, 2002, Enron announced that it has commenced a formal sales process for its interests in certain major assets, including PGE. In its announcement, Enron indicated that it is extending invitations to visit electronic data rooms containing information on 12 of its most valuable businesses to a broad universe of potential bidders with whom Enron has executed confidentiality agreements.

Enron's announcement stated that the sales process continues Enron's efforts to maximize value and enhance recovery for its creditors. Enron and its advisors, in consultation with the Unsecured Creditors' Committee and its advisors, will evaluate all offers received to determine the combination of bids that maximizes the value of all assets.

PGE has been informed by Enron management that Enron and its advisors are continuing to review bids received on certain of its North American properties, including PGE. However, Enron has stated that it reserves the right not to sell any assets if the bids received are not deemed fully reflective of the aggregate value of such assets. A sale of PGE would require the consideration and approval of regulatory agencies, including the OPUC. Until there is a filing with the Bankruptcy Court, management cannot assess the impact of a sale or other arrangement on PGE's business and operations.

Public Ownership Initiatives

In August 2002, the City Council of Portland, Oregon passed a resolution authorizing the expenditure of up to $500,000 for professional advice regarding the City's potential acquisition of PGE, including possible condemnation of the Company's assets. The City has signed a confidentiality agreement with Enron to permit it to participate in the Enron auction process relating to PGE.

Initiative petitions circulated in Multnomah County obtained sufficient signatures to place a measure on an election ballot in the fall of 2003 that, if passed, could result in the formation of a Peoples' Utility District (PUD) in Multnomah County. In addition, if this measure succeeds, the expressed intent of its supporters is to hold additional elections to expand the boundaries of the district to include all of PGE's service territory. If a PUD is formed, it would have the authority to condemn PGE's distribution assets within the boundaries of the district. Oregon law prohibits the PUD from condemning thermal generation plants. It is uncertain under Oregon law whether the PUD would be able to condemn PGE's hydro-generation plants.

PGE opposes the formation of the PUD and will oppose any efforts to condemn the Company's assets.

Complaint to OPUC - State and Local Taxes

On March 7, 2003, the Utility Reform Project and Linda K. Williams (Complainants) filed a Petition to Open Investigation and Complaint with the Public Utility Commission of Oregon. Complainants request the Commission open an investigation to determine the amount of state and local taxes paid by PGE since 1997. Complainants allege PGE's rates were not just and reasonable from 1997 because they contained charges for state and local taxes that PGE may never have paid. PGE will file an answer to the Complaint and oppose the relief sought by Complainants.

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. Under this mechanism, PGE shared with its retail customers differences 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. (See "Power Cost Mechanisms" below).

Power Cost Mechanisms

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. During the initial power cost 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, 2002, the remaining balance to be collected was approximately $73 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 for recovery from customers both 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 balance is being collected from large industrial customers over a one-year period (2003) and over a two-year period (2003-2004) from all other customer classes. At December 31, 2002, the balance to be collected, which is subject to a prudence review and audit by the OPUC, was approximately $36 million.

Although PGE does not currently have a power cost mechanism in place in 2003, the Company has filed with the OPUC an application to defer for later ratemaking treatment increases in power costs related to adverse hydro conditions (see "Hydro Replacement Power Costs" for further information).

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. 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 its projected power costs change from those included in its 2001 general rate case. It provides for an adjustment, filed annually on November 15, 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 utilized in the Company's 2001 general rate case. Accordingly, the OPUC authorized reductions in the Company's retail prices, effective January 1, 2003. Price decreases range 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 have decreased in the 2003 forecast. The smaller decrease in residential rates reflects the higher cost of electricity from BPA, which increased its rates in October 2002, as well as PGE's cost of generation. Based upon projected energy sales, it is estimated that such price decreases will reduce PGE's 2003 revenues by approximately $100 million.

Included in the price reduction is the effect of the Commission's disallowance of approximately $15 million related to four power purchase contracts, entered into in the first half of 2001, providing 125 megawatts of on-peak delivery in 2003. The disallowance was based upon a prudency review that included an evaluation and comparison of average prices contained in such contracts, reflecting the volatile wholesale market that existed at the time of their inception, with current market prices.

The new prices also reflect a resolution regarding the recovery period for the approximate $36 million balance related to PGE's power cost mechanism covering the period October 2001 through December 2002. This amount includes the effect of a settlement stipulation related to estimated 2003 power costs, in which PGE agreed to reduce its recovery under the power cost mechanism by approximately $4.6 million; such reduction was recorded by the Company in 2002.

Integrated Resource Plan

In August 2002, PGE filed a new Integrated Resource Plan. In its Plan, PGE describes its strategy to meet the electric energy needs of its customers, with an emphasis on cost, long-term price stability, and supply reliability. The Plan, which considers resource actions over the next two to three years, includes reduced reliance on short-term wholesale power contracts and increased emphasis on longer-term supplies. It also considers future investment in additional generating resources (including upgrades to existing resources), an increase in renewable resources, long-term power purchases, and meeting seasonal peaking requirements through seasonal exchanges, demand-side management, capacity tolling contracts, and combustion turbine development.

PGE filed a supplement to the Plan on February 28, 2003. The OPUC has initiated a schedule for input and review, with an acknowledgement of the Company's Plan, as supplemented, anticipated by mid-2003. PGE then anticipates issuing a request for proposals (RFP) to acquire energy and capacity resources. The Company will continue to evaluate its options with regard to the construction of additional generation (including the Port Westward gas turbine project), and the availability of reasonably priced medium to long-term power purchases from the market. PGE will continue to monitor changes in economic conditions and the effect of restructuring legislation that allows large customers to purchase power directly from electricity service suppliers.

Based upon results of the RFP process, PGE will update its action plan with specific resource recommendations and request acknowledgement that the Company's final action plan is consistent with least cost planning principles established by the OPUC.

Receivables - California Wholesale Market

As of December 31, 2002, PGE has net accounts receivable totaling approximately $62 million from the California Independent System Operator (ISO) and the California Power Exchange (PX) that may be affected by the financial condition of two major California utilities. 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). Both the PX and PG&E have filed for bankruptcy. PGE is pursuing collection through the PX and PG&E bankruptcies. A credit reserve has been established by PGE for a portion of the total amount due under its wholesale electricity contracts. Due to uncertainties surrounding both the bankruptcy filings and regulatory reviews of sales made during this time period, management cannot predict the ultimate realization of these receivables. Management believes that the outcome of this matter 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. For further information, see Note 13, Receivables-California Wholesale Market, in the Notes to Financial Statements.

Refunds on Wholesale Transactions

The FERC has issued an order to consider refunds for sales by electricity suppliers, including PGE, in the California spot market between October 2, 2000 and June 20, 2001. Hearings were held during 2002 to determine the amount of these refunds and also to determine amounts still owed to sellers. The presiding administrative law judge issued a certification of facts and the matter is now pending decision by the FERC. FERC hearings were also held in 2001 to determine whether there may have been unjust and unreasonable charges, and whether refunds may be due, for spot market sales of electricity in the Pacific Northwest by PGE and other suppliers from December 25, 2000 through June 20, 2001. An administrative law judge recommendation that no refunds be ordered is also pending before the FERC.

In late 2002, the FERC reopened the records in both the California case and the Pacific Northwest case to allow the parties to conduct additional discovery and to submit additional evidence regarding possible manipulation of the two markets. On March 3, 2003, numerous parties filed documents in both refund dockets addressing that issue. The most comprehensive filings were by the City of Tacoma in the Pacific Northwest case and by the California Parties in the California case. In addition to alleging that the markets were manipulated and that the refund cases should thus be expanded, those two parties alleged that numerous sellers, including PGE, participated in various strategies that adversely affected the market. PGE will be filing responses to the allegations in both dockets in late-March 2003.

The FERC has indicated that any refunds PGE may be required to pay related to California sales can be offset by accounts receivable related to sales in California. In addition, any refunds paid or received by PGE applicable to spot market electricity transactions on and after January 1, 2001 in California and the Pacific Northwest may be eligible for inclusion in the calculation of net variable power costs under the Company's power cost mechanism in effect during 2001-2002, which could further mitigate the financial effect of any refunds made or received by the Company.

Management cannot predict the ultimate outcome of these matters. 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. See Note 13, Receivables - California Wholesale Market, and Note 14, Refunds on Wholesale Transactions, in the Notes to Financial Statements for further information.

Wholesale Price Mitigation

In June 2001, the FERC adopted a price mitigation program for the power system serving 11 Western states, adopting a new benchmark formula limiting prices for electricity sold in the spot markets at all times throughout the region through September 2002. The program applied to power generators, marketers, and investor-owned utilities under FERC jurisdiction, as well as public power providers, municipal utilities, and electric cooperatives that use FERC-regulated transmission lines.

Under the program, a ceiling price was set by FERC for wholesale electricity sold in the spot market coordinated by the California Independent System Operator (ISO) and in markets in the other Western states. Such price, initially set at $91.87/MWh, reflected specified fuel, operations, and maintenance costs, and was based upon the bid submitted by the highest cost gas-fired generating unit supplying power during a Stage 1 supply emergency.

In December 2001, the FERC temporarily modified the method for calculating the ceiling price for markets in Western states not coordinated by the ISO, recognizing differences between Northwest and California markets, including those related to hydropower utilization and seasons of peak usage. The changes, including a ceiling price of $108/MWh, were in effect until May 1, 2002, at which time the previous methodology and ceiling price again became effective.

In July 2002, the FERC raised the ceiling price on Western wholesale electricity prices from $91.87/MWh to $250/MWh, effective October 31, 2002. The new ceiling price applies to all sales of electricity in the WECC. In addition to the new price ceiling, the FERC order established conditions and rules guiding participation in Western wholesale electricity markets, including automatic price mitigation procedures to be implemented during periods of tight supplies.

Federal Investigations - Wholesale Power Markets

On February 13, 2002, the FERC initiated a fact-finding investigation into whether any entity manipulated short-term prices in electric energy or natural gas markets in the West, or otherwise exercised undue influence over wholesale prices in the West, since January 1, 2000. On March 5, 2002, all sellers with wholesale sales in the U.S. portion of the WECC were directed to provide certain historical and projected information for all energy transactions in calendar years 2000 and 2001. In April 2002, the Company submitted the requested information. Additionally, on March 15, 2002 the FERC enforcement staff issued a subpoena to Enron, which Enron then forwarded to the Company. In response to this subpoena, the Company provided information related to its trading organization, its trading policies and procedures, its price curves and their derivation, and its trading position reports.

As a result of an internal investigation, PGE discovered that it had failed to properly post on a public web site information about a number of energy transactions with an affiliate, Enron Power Marketing, Inc. The preliminary results of this investigation were disclosed to FERC Staff on April 15, 2002 and final results on August 1, 2002. This issue was subsequently included in the investigation in Docket No. EL02-114-000 described below.

Enron Trading Strategies

In early May 2002, the FERC received information contained in memos released by Enron, indicating that Enron, through its subsidiary Enron Power Marketing, Inc. (EPMI), may have engaged in several types of trading strategies that raised questions regarding potential manipulation of electricity and natural gas prices in California in 2000-2001.

On May 8, 2002, the FERC ordered all sellers of wholesale electricity or ancillary services into the California markets during 2000-2001 to respond to the FERC whether they engaged in any transactions falling within any of the enumerated types of trading strategies, and, if they did, to provide information about the transactions. Although PGE was not specifically named in the FERC order, on May 22, 2002, PGE voluntarily submitted the results of its investigation to the FERC. The material submitted to FERC did not show any instances where the Company engaged in or knowingly aided deceptive or misleading trading strategies. However, PGE reported that it was among other intermediaries in a series of trading activities that occurred on 15 days from April through June 2000 where EPMI was found to be at both ends of the transaction chain. The trading transactions identified during the 15-day period moved about 2,300 megawatt hours (0.12%) of the total 2 million megawatt hours traded by PGE on those days, and about 0.02% of the total 13 million megawatt hours traded by PGE during the three-month period. The services provided by PGE may have been used by EPMI as a step in one of the enumerated strategies. In addition, it is conceivable that in the normal course of business, PGE could have provided services to third parties that may have resulted in PGE being used, unknowingly, as an intermediary in partial execution of one or more of the enumerated strategies.

On June 4, 2002, the FERC issued an order to PGE and three other companies to show cause why their authority to charge market-based rates should not be revoked. The order stated that the companies' responses to the FERC's May 8, 2002 data request (discussed above) are indicative of a failure to cooperate with its investigation. On June 14, 2002, PGE filed a response indicating that a thorough review of Company documents again found no evidence of deception or market manipulation by PGE. PGE believes that it has fully cooperated with the FERC's inquiry.

On August 13, 2002, the FERC issued two orders initiating investigations into instances of possible misconduct by PGE and certain other companies. In the first order (Docket No. EL02-114-000), the FERC ordered investigation of PGE and EPMI related to possible violations of their codes of conduct, the FERC's standards of conduct, and the companies' market-based rate tariffs, and whether PGE has cooperated by providing all relevant information related to the FERC's May 8, 2002 data request and June 4 Show Cause Order. In the second order (Docket No. EL02-115-000), the FERC ordered investigation of Avista Corporation and Avista Energy, Inc. (collectively, Avista) with respect to, among other things, transactions in which Avista engaged in or facilitated the trading strategies identified in the Enron memoranda or acted as a middleman with respect to sales of electric energy between PGE and EPMI. PGE and EPMI are included as parties in that Docket. In the orders, the FERC established October 15, 2002 as the "refund effective date." Issues involving PGE and EPMI in Docket No. EL02-115-000 have now been consolidated into Docket No. EL02-114-000. If PGE were to lose its market-based rate authority, purchasers of electric energy from PGE at market-based rates after that date could be entitled to a refund of the difference between the market-based rates and cost-based rates deemed just and reasonable by the FERC.

On December 10, 2002, the FERC trial staff released a Revised Statement of Asserted Violations (Revised Statement) and its initial testimony in its investigation of PGE (Docket No. EL02-114-000). The assertions in the Revised Statement and testimony are limited to PGE's self-reported failure to properly post information about energy transactions with EPMI, and alleged violations for affiliate dealings with EPMI relating to a series of transactions that occurred on certain days in April-June 2000, involving PGE, EPMI, and Avista Corporation. The latter transactions were previously reported by PGE to FERC on May 22, 2002 in response to the FERC's May 8, 2002 data request. The trial staff recommended a remedy of revocation of PGE's market-based rate authority for two years, and a requirement that PGE's application for reinstatement of market-based rates include documentation supporting revised procedures to ensure that posting errors and violations of affiliate rules do not occur again. The City of Tacoma, Washington filed testimony seeking a refund from PGE of $3.2 million. The California Attorney General and the California Public Utilities Commission (California Parties) have filed testimony that PGE should refund amounts to compensate market participants for PGE's alleged unlawful conduct, but the testimony specifies no amount of refunds.

PGE's initial response testimony was filed on February 24, 2003. In its testimony, PGE describes the posting errors it self-reported, most of which were technical in nature, and the cooperation it has extended to the FERC, the investigative staff, and the trial staff to furnish all requested information to aid the investigation. PGE also provided testimony that the April-June 2000 transactions with EPMI did not involve violations of affiliate rules, except for certain posting errors.

The hearing in Docket No. EL02-114-000 is scheduled to begin on June 2, 2003, with an initial decision from the presiding FERC judge scheduled for July 17, 2003. The schedule in Docket No. EL02-115-000 is currently suspended pending the disposition of a settlement proposal submitted between Avista and the FERC trial staff.

PGE will continue to cooperate with the investigations. PGE continues to believe that it has fully complied with the FERC investigation initiated on February 13, 2002, and that it has not engaged in deception or market manipulation.

Wash Sales - Electricity

On May 21, 2002, the FERC issued a data request and request for admissions to all sellers of wholesale electricity and/or ancillary services in the U.S. portion of the WECC during the years 2000-2001. Such request ordered sellers to admit or deny engagement in activities referred to as "wash," "round trip," or "sell/buyback" type transactions. Although PGE was not listed in the data request, PGE conducted an investigation and submitted the results in a response to the FERC on May 31, 2002. Such response denied that PGE engaged in trading activities described in the FERC data request to the extent that such activities artificially inflated trading volumes, revenues or market prices. PGE's response also noted that it had no reason or incentive to artificially inflate trading volumes or revenues, as the primary purpose of its wholesale trading operations is to manage risk and reduce costs for its retail customers by balancing load requirements and maximizing the value of owned generation and purchase contracts to the extent that available supply exceeds the needs of the Company's firm customers.

Wash Sales - Natural Gas

On May 22, 2002, the FERC issued a data request and request for admissions to all sellers of natural gas in the U.S. portion of the WECC and in Texas during the years 2000-2001. Such request ordered such sellers to admit or deny engagement in activities referred to as "wash," "round trip," or "sell/buyback" type transactions. PGE conducted an investigation and submitted the results in a response to the FERC on June 5, 2002. Such response denied that PGE engaged in trading activities described in the FERC data request.

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, where briefing is now underway.

Other

On June 17, 2002, the U.S. Commodity Futures Trading Commission (CFTC), which regulates futures contracts traded on U.S. exchanges, subpoenaed documents from PGE regarding the Company's electricity and natural gas trading, including any "wash" trading used to inflate revenue and trading volume. PGE forwarded documents previously prepared for the FERC investigation (described above). In addition, PGE has been requested to provide information and documents with respect to various federal and state actions and investigations of Enron. PGE will continue to cooperate to the fullest extent with these investigations.

Antitrust Litigation

In late 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) 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.

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, 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 cross complaint against PGE and the other utilities, generators, traders and other entities similar to the cross complaint filed by the Duke Parties. The cases were remanded to Federal Court by certain parties. The parties have stipulated to place the cross complaints in abeyance until 30 days after a ruling on the motions to dismiss the Master Complaint.

On December 13, 2002, a United States District Court signed an order granting the plaintiff's motions to remand the cases to the California state court, but the order was not immediately implemented. The Duke and Reliant Parties filed an appeal to the United States Ninth Circuit Court of Appeals and applied to the District Court for a stay of the remand to the California state court. On January 24, 2003, the District Court denied the application for a stay and set for hearing certain motions for reconsideration. 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 and set a briefing schedule that will not be completed until mid-September 2003. 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.

At this time, management is unable to make any assessment of, or determination with respect to, these complaints.

California Attorney General Complaint

In May 2002, the Attorney General of California filed a complaint in state court alleging failure of PGE to comply with the Federal Power Act (FPA) and with the FERC requirements for its market based sales of power in California. The complaint seeks fines and penalties under the California Business and Professions Code for each sale from 1998 through 2001 above a "capped price" or a reasonable price and for each alleged regulatory violation. No specific damage claim is stated. In July 2002, PGE filed a Notice of Removal to U.S. District Court and a Motion to Dismiss on preemptive grounds. The Attorney General moved to remand to state court, which was denied. The Attorney General filed an appeal to the Ninth Circuit Court of Appeals of the denial of the motion to remand, and moved to stay action in the District Court pending the outcome of the appeal. The District Court, finding the appeal frivolous, refused to stay the case. Motions to dismiss the case were argued on September 26, 2002 and are currently under advisement by the District Court. At this time, management is unable to make any assessment of, or determination with respect to, this complaint. See Note 13, Receivables - California Wholesale Market, and Note 14, Refunds on Wholesale Transactions, in the Notes to Financial Statements for further information.

Washington Consumers' Class Action Suit

On December 20, 2002, a Class Action suit on behalf of consumers in the State of Washington was filed against participants in the Pacific Northwest electric power markets, including PGE. The suit alleges violation of the Washington Consumer Protection Act, fraud by concealment, and negligence. The relief sought includes treble damages, attorney fees, and injunctive relief to prohibit the unlawful practices alleged. No monetary amount is specified. Plaintiff has agreed to extend the time for all defendants to respond until after April 2, 2003.

Trojan Investment Recovery

Due to the closure of the Trojan Nuclear Plant in 1993 and issuance of a 1995 OPUC general rate order in connection with the recovery of and a return on the Trojan investment, numerous legal challenges, appeals, and regulatory actions have taken place. As a result of a settlement agreement that was implemented in 2000, the recovery of the Trojan plant investment is no longer included in rates charged to customers. The Company continues to collect for costs related to the decommissioning of the plant.

On January 17, 2003, two class actions suits were filed 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. PGE intends to vigorously defend these cases.

Although management cannot predict the ultimate outcome of the above legal challenges, it believes that they 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. For further information, see Note 10, Legal and Environmental Matters, in the Notes to Financial Statements.

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, with respect to losses in their pension/savings plan attributable to the collapse of the price of Enron's stock. For further information, see Note 10, Legal and Environmental Matters, in the Notes to Financial Statements.

Regulation and Competition

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 energy suppliers.

State

In 1999, Oregon's governor signed into law State Senate Bill 1149, which became effective March 1, 2002. It provides all commercial and industrial customers of investor-owned utilities direct access to energy suppliers 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 new 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 payment of "transition charges" by non-residential customers that choose to purchase energy at market rates from investor-owned utilities or from electricity service suppliers. Such charges reflect the above-market cost of energy resources owned or purchased by the utility and are designed to ensure that such costs do not unfairly shift to the utility's remaining energy customers.

The new 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 of Oregon's electric energy restructuring law indicate a measured response. Although numerous customers have chosen among available rate options, no customers have yet left PGE's system for competing electricity service suppliers.

PGE continues to operate as a cost-based regulated electric utility, where 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 bundled ("full") 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 will continue to periodically assess the applicability of the statement to its business, or separable portions thereof. Such assessment will 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.

In accordance with the new law and an order from the OPUC, PGE is deferring certain costs related to implementation of the restructuring plan for later recovery in electricity rates. At December 31, 2002, unrecovered costs totaled approximately $20 million. The OPUC staff recently completed an audit and prudency review of such costs, and in January 2003 issued a report that found these costs to be prudently incurred, with only minor adjustments proposed.

Federal

The Energy Policy Act of 1992 (Energy Act) set the stage for change in federal regulations aimed at increasing 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.

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 Customer Growth and Energy Sales

Weather adjusted retail energy sales decreased 1.9% in 2002. Excluding the effects of the Demand Buyback program, in which PGE paid large customers to reduce their load during peak demand times in 2001, weather adjusted sales declined about 3.2%. Such decreases are attributable to the continuing effect of a significant downturn in Oregon's economy. Manufacturing sector sales decreased about 2.1%, as large paper, chemical, food, lumber and metals manufacturers reduced their energy use; excluding the effects of the Demand Buyback program, manufacturing sector sales declined about 7%. Commercial sales declined 3.0% compared to 2001. Sales to residential customers, adjusted for the effects of weather, decreased 0.8% as average use declined in response to conservation efforts; such decrease was partially offset by an approximate 1% increase in residential customers served. PGE forecasts minimal retail energy sales growth in 2003 due to Oregon's continued slow economy.

Energy Efficiency

PGE has consistently promoted the efficient use of electricity, utilizing Demand Side Management programs that provide a range of services to all customer classes and that seek to maximize those opportunities in which energy efficiency measures are most cost-effective. To accomplish this, the Company focuses on both commercial and industrial new construction and retrofitting, industrial process improvements, and residential weatherization measures, including an expanded program that encouraged the use of compact fluorescent lighting and a program for low-income families.

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 (ETO), 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. As the ETO more fully develops its energy efficiency programs, it is utilizing transition contracts with utilities to assure energy efficiency programs are available to customers.

In 2002, PGE acquired total energy savings for residential, commercial, and industrial customers estimated at 11 average megawatts, including 6 average megawatts under the Company's transition contract with ETO. PGE will continue to offer customers general energy information to assist them in managing their energy costs.

Wholesale Sales

The amount of surplus electric generating capability in the western United States, the amount of the 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. During 2002, PGE's wholesale sales accounted for about 21% of total revenues and 40% of total energy sales. 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 take advantage of price movements in electricity, natural gas, and crude oil.

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 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.

During 2002, PGE generated approximately 38% of its retail load requirement, compared to approximately 61% in 2001, as lower cost power purchases displaced the Company's thermal generation. Short-term and long-term purchases were utilized to meet the remaining load. PGE has long-term power contracts with four hydro projects on the mid-Columbia River providing capability of 652 MW, and has also relied increasingly upon short-term purchases to meet its energy 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 hydro conditions in 2003 will be significantly below normal. 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 2003 runoff at 73% of normal, compared to 97% in 2002 and 54% in 2001. Efforts to restore salmon runs on the Columbia and Snake rivers may additionally reduce the amount of water available for generation, which could affect the availability and price of purchased power. PGE continues to evaluate the impact of current and potential listings of salmon species for protection under the federal Endangered Species Act on its purchased power supply and the operation of its hydroelectric projects on the Deschutes, Sandy, Clackamas, and Willamette Rivers.

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.

Hydro Replacement Power Costs

A region-wide drought throughout the Pacific Northwest has resulted in adverse hydro conditions for PGE and other utilities, with early forecasts indicating hydro conditions significantly below normal. In anticipation of the effects of such conditions, PGE has begun to acquire replacement power resources for the expected shortfall in hydro-based power, incurring substantially higher variable power costs than those contained in the Company's current energy rates.

On February 11, 2003, PGE filed with the OPUC an Application for Deferral of Hydro Replacement Power Costs, in which the Company requests authorization to defer for later ratemaking treatment increases in power costs incurred from the application date through December 31, 2003. The Company's application requests authorization for the deferral of 95% of the difference between actual net variable power costs and those allowed in current rates, with interest accrued at PGE's authorized rate of return. As proposed, the deferral would be adjusted for the impact that changes in load would otherwise have on net variable power costs. Although the amount of the deferral is not yet determinable due to the effect of uncertain and unpredictable weather patterns for the remainder of the year, PGE estimates that the amount could range from $20 million to $60 million.

Residential Exchange Program

PGE and 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 in the form of lower prices, are reflected within Purchased power and fuel expense.

Hydro Re-licensing

PGE Hydro

- PGE's five FERC-licensed hydroelectric projects consist of eight facilities which provide economical generation and flexible load following capabilities. In 2002, they produced approximately 1.8 million MWh of renewable energy, about 9% of PGE's total retail customer load. The plants operate under federal licenses, which will be up for renewal through 2006. Costs of relicensing the Company's hydroelectric projects are being capitalized for future rate recovery.

The Clackamas River hydroelectric projects have a combined output of 175 MW. PGE continues to involve resource agencies, environmental groups, tribal governments, and members of the public in the design and implementation of studies that will help PGE and the parties understand the projects' impacts and opportunities for mitigation and enhancements in the new license. The existing license expires in August 2006 and a draft application will be filed with the FERC in 2003.

PGE filed a license application with the FERC in December 2002 for its 16-MW Willamette River hydroelectric project, whose current license expires in December 2004. In 2003, the Company and participants in the relicensing process will continue to develop a plan for the timing and monitoring of proposed modifications to the generating project and facilities. Biological evaluation, to be used in ESA consultation undertaken by the FERC, will continue in 2003.

PGE and the Tribes filed their final joint application amendment for the Pelton Round Butte project on the Deschutes River in June 2001. PGE has a 300-MW ownership share in the 450-MW project following the January 2002 sale of a portion of the project to the Tribes. During 2003, participants in the relicensing process will continue in settlement discussions to seek agreement on the terms and conditions of the new license. The project has been operating on annual licenses since its FERC license expired in December 2001.

Mid-Columbia Hydro -

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. The new agreements are effective upon expiration of the current contracts 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 output will decline over time as Grant's needs increase, with an expected share of about 15 average megawatts in 2009.

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. PGE filed a request for rehearing with FERC on December 23, 2002 and expects an order by FERC on the merits in the spring of 2003.

For further information regarding the power purchase contracts on the mid-Columbia dams, including Priest Rapids and Wanapum, see Note 7, Commitments, in the Notes to Financial Statements

Hydroelectric Project Removal

In October 2002, PGE entered into an agreement with state and federal agencies, conservation groups, and others regarding the removal of the Company's 22-MW Bull Run hydroelectric project on the Sandy River, 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.

Under the terms of the agreement, PGE has requested that the term of the existing license, which expires in November 2004, be extended to allow the project to operate until the removal of Little Sandy Dam. 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.

The decision and agreement were based upon a comparison of projected future operating costs of the project, including required environmental measures necessary to protect several runs of endangered salmon, with the future value of the project's energy output. PGE has filed an application to amend the project license and an application to surrender the Bull Run license. A FERC decision on the amendment application and surrender application is expected in 2003.

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 is expected to be completed by the end of 2003. PGE also completed the final radiological survey of the containment building and areas impacted by the completed ISFSI. The Company supported the NRC's collection of confirmatory surveys of containment and ISFSI impacted areas with no significant findings or observations.

PGE currently estimates the total cost to decommission Trojan at $345 million (nominal dollars), with approximately $169 million expended through 2002. The total estimate assumes that the majority of decommissioning activities will be completed by 2005 after the spent fuel has been transferred to dry storage. The plan anticipates final site restoration activities will begin in 2018 after PGE completes shipment of spent fuel to a USDOE facility. Total decommissioning costs are currently estimated at approximately $25 million for 2003, compared to $18 million expended in 2002.

PGE expects remaining transition activities to extend through 2003; such activities consist of operating and maintaining the spent fuel pool and securing the plant until fuel is transferred to dry storage. 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.

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 such time as the NRC determines that the level of threat has diminished, or that other security changes are needed. The NRC has begun a comprehensive re-evaluation of current safeguards and security programs, and PGE anticipates formal regulations to be issued in late 2003. Until NRC requirements are determined, it is not known whether the costs associated with their implementation 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 11, Trojan Nuclear Plant, in the Notes to Financial Statements.

Environmental Matter

A 1997 investigation of a 5.5 mile segment of the Willamette River known as the Portland Harbor, conducted by the EPA, 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 2000.

In 1999, the DEQ asked that PGE perform a voluntary remedial investigation of its Harborton Substation site to confirm whether any regulated 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 accordance with the Voluntary Agreement, in March 2001, 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 a final investigation report to the DEQ summarizing its investigations conducted in accordance with the May 2000 Voluntary Agreement. The report indicated that such investigations demonstrated that there is no likely present or past source or pathway for release of hazardous substances to surface water or sediments at or from the Harborton Substation site. Further, the investigations 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.

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. Available information is currently not sufficient to determine either the total cost of investigation and remediation of the Portland Harbor or the liability of Potentially Responsible Parties, including PGE.

Management believes that the Company's contribution to the sediment contamination, if any, would qualify it as a de minimis Potentially Responsible Party. Nonetheless, management cannot predict the ultimate outcome of this matter or estimate any possible loss.

For further information, see Note 10, Legal and Environmental Matters, in the Notes to Financial Statements.

RTO West and Independent Transmission Company

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 FERC issued an order in 1999 that requires all owners of electricity transmission facilities to file a proposal to join a Regional Transmission Organization (RTO). For further information, see "Regulatory Matters" in Part I, Item 1. - Business.

Public Utility Holding Company Act of 1935

All of the common stock of PGE is owned by Enron. As the owner of PGE's common stock, Enron is a holding company for purposes of PUHCA. Following Enron's acquisition of PGE in 1997, Enron annually filed on Form U-3A-2 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 on Form U-3A-2. As a result, in February 2002, Enron filed an application on Form U-1 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.

Following the submission of testimony by the parties to the proceeding, a hearing on Enron's application was held on December 5, 2002. On February 6, 2003, the administrative law judge issued an Initial Decision holding that PGE does not meet the criteria to be predominantly intrastate in character, and denying Enron's application for exemption under 3(a)(1). On February 27, 2003, Enron filed a Petition for Review with the SEC requesting that the SEC review the Administrative Law Judge's Initial Decision, reverse such Initial Decision, and find that Enron is entitled to exemption from PUHCA. Filing of the Petition for Review stays the effect of the Initial Decision until such time as the SEC may act on the Petition for Review. The SEC could act on the Petition for Review at any time. Possible responses of the SEC to the Petition for Review include setting the matter down for further hearings before the full Commission or summarily affirming the Initial Decision. In the event that the Initial Decision is affirmed by the SEC, either summarily or after further hearings, Enron could be required to register as a holding company under PUHCA and PGE would become a subsidiary of a registered holding company.

PUHCA imposes a number of restrictions on the operations of a registered holding company and its subsidiaries, including SEC approval of securities issuances (including those by utility subsidiaries that have not been authorized by the relevant state utility commissions) and engaging directly or indirectly in non-utility businesses. PUHCA also regulates transactions between the affiliates within the holding company system, including the provision of services by holding company affiliates to the system's utilities. If PGE were to become a subsidiary of a registered holding company, it would become subject to regulation by the SEC not only with respect to the acquisition of the securities of other public utilities, but also with respect to, among other things, payment of dividends out of capital and surplus, certain affiliate transactions, issuance of securities, and the acquisition of assets and interests in any other business.

Although PGE is unable to predict whether Enron will retain its status as an exempt holding company, PGE does not believe that becoming a subsidiary of a registered holding company would have a material adverse affect on its financial condition or results of operations. However, the finding that PGE is not an intrastate utility could make it more difficult for any future owner of PGE to obtain a 3(a)(1) exemption from PUHCA.

New Accounting Standards

See Note 1, Summary of Significant Accounting Policies, in the Notes to Financial Statements for information regarding new accounting standards.

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;
- effects of electric industry restructuring in Oregon and in the United States, including 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 which include changes in commodity prices, foreign exchange rates and interest rates. These changes may affect the Company's future financial results.

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 seasonal 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, 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 2002 was $0.1 million, $0.4 million, and zero, respectively, in 2001 was $0.8 million, $3.6 million, and zero, respectively, and in 2000 was $0.3 million, $0.5 million, and zero, respectively. The instances of zero value at risk occur when there are no open positions in the trading portfolio. For 2002 and 2001, the value at risk on the non-trading portfolio is not meaningful since the majority of the portfolio is effectively accounted for on an accrual or settlements basis. Additionally, PGE had power cost mechanisms in 2001-2002 that allowed the Company to defer, for future ratemaking treatment, actual net variable power costs that differed from certain baseline amounts approved by the OPUC (see "Power Cost Mechanisms" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operations"). In 2002 and 2001, PGE did not reduce its non-trading value at risk by the amount of potential deferrals. For 2000, the average, high, and low value at risk on the non-trading portfolio was $2.0 million, $4.6 million, and $1.1 million, respectively.

Foreign Currency Exchange Rate Risk

PGE faces exposure to foreign currency risk associated with natural gas forward and swap contracts denominated in Canadian dollars, primarily in its non-trading portfolio. Foreign currency risk is the risk of changes in value of pending financial obligations in foreign currencies that could occur prior to the settlement of the obligation due to a change in the value of that foreign currency in relation to the U.S. dollar. PGE monitors its exposure to fluctuations in the Canadian exchange rate with an appropriate hedging strategy. Beginning in 2003, PGE implemented a strategy that utilizes forward contracts to acquire Canadian dollars in order to mitigate its currency exposure.

At December 31, 2002, a 10% change in the value of the Canadian dollar would result in a change in pre-tax income of approximately $4 million at the time the transactions settle over the next 22 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, 2002, the Company is typically exposed to risk resulting from changes in interest rates on variable rate short-term borrowings. The Company has also had exposure to interest rate changes on variable rate commercial paper, which it has recently been unable to issue due to reductions in its credit ratings. Although PGE currently has no financial instruments to mitigate such risk, it will consider such instruments in the future as necessary.

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

		Carrying Amounts by Maturity Date						
	Total Fair							After
	Value	Total	2003	2004	2005	2006	2007	2007
First Mortgage Bonds	$ 570	$ M63	$ 40	$ 45	$18	$ -	$50	$L10
Pollution Control Revenue Bonds	186	194	142	-	-	-	-	52
Other	254	261	9	10	10	9	-	223
Total	$1,010	$I,018	$191	$M5	$28	$9	$50	$N85

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

Credit Risk

PGE is exposed to credit risk in its commodity price risk management activities related to potential nonperformance by counterparties. PGE manages the risk of counterparty default according to its credit policies by performing financial credit reviews 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. Due to the settlement of power contracts in 2002, the Company's exposure to credit risk has decreased significantly.

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 1, Summary of Significant Accounting Policies, and Note 8, Price Risk Management, in the Notes to Financial Statements.

Item 8. Financial Statements and Supplementary Data

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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.

The system of internal controls of PGE is designed to provide reasonable assurance as to the reliability of financial statements and the protection of assets from unauthorized acquisition, use or disposition. This system is augmented by written policies and guidelines and 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 internal control system 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.

PricewaterhouseCoopers LLP was engaged to audit the 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 Report of Independent Accountants appears 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 accountants have direct access to the Audit Committee, and they meet with the committee from time to time, with and without financial management present, to discuss accounting, auditing and financial reporting matters.

Report of Independent Accountants

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

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a) present fairly, in all material respects, the financial position of Portland General Electric Company and its subsidiaries at December 31, 2002 and 2001, and the results of their operations and their cash flows for each of the three 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	2002	2001	2000
	(In Millions)		
Operating Revenues	$1,855	$2,420	$1,887
Operating Expenses			
Purchased power and fuel	1,157	1,734	1,095
Production and distribution	118	128	126
Administrative and other	147	151	137
Depreciation and amortization	161	170	164
Taxes other than income taxes	69	65	65
Income taxes	68	38	94
	1,720	2,286	1,681
Net Operating Income	135	134	206
Other Income (Deductions)			
Provision for uncollectible accounts receivable from affiliates	(6)	(79)	-
Miscellaneous	(2)	4	10
Income taxes	10	36	(3)
	2	(39)	7

Interest Charges					
	Interest on long-term debt and other	67	68	63
	Interest on short-term borrowings	4	4	9
		71	72	72
Net Income before cumulative effect of a change in accounting principle		66	23	141
Cumulative effect of a change in accounting principle, net of related taxes of $(6)		-	11	-
Net Income		66	34	141
Preferred Dividend Requirement		2	2	2
Income Available for Common Stock		$ 64	$ 32	$ 139

Portland General Electric Company and Subsidiaries

Consolidated Statements of Retained Earnings

For the Years Ended December 31	2002	2001	2000
	(In Millions)		

Balance at Beginning of Year		$ 451		$ 459		$ 401
Net Income		66		34		141
		517		493		542
Dividends Declared						
Common stock (non-cash dividend in 2002)		27		40		81
Preferred stock		2		2		2
		29		42		83
Balance at End of Year		$ 488		$ 451		$ 459
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		2002		2001		2000
		(In Millions)				
Accumulated other comprehensive income (loss) - Beginning of Year						
Minimum pension liability adjustment		$ (2)		$ -		$ -
Total		$ (2)		$ -		$ -
Net Income		$ 66		$ 34		$141

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 $(4) in 2002 and $37 in 2001	7	(56)	-
Reclassification adjustment for contract settlements included in net income, net of related taxes of $(1) in 2002 and $7 in 2001	1	(10)	-
Reclassification adjustment in net income due to discontinuance			
of cash flow hedges, net of related taxes of $(19)in 2001	-	30	-
Reclassification of unrealized gains (losses) to SFAS No. 71			
regulatory (liability) asset, net of related taxes of $3 in 2002 and $(1) in 2001	(5)	1	-
Total - Unrealized gains on derivatives classified as cash flow hedges	3	-	-
Minimum pension liability adjustment	(1)	(2)	-
Total Other comprehensive income (loss)	2	(2)	-

	Comprehensive income		$ 68		$ 32		$141
Accumulated other comprehensive income (loss) - End of Year							
	Unrealized gain (loss) on derivatives classified as cash flow hedges		$ 3		$ -		$ -
	Minimum pension liability adjustment		(3)		(2)		-
Total			$ -		$ (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			2002		2001
			(In Millions)		
Assets					
Electric Utility Plant - Original Cost					
	Utility plant		$ 3,706		$ 3,596
	Accumulated depreciation		(1,768)		(1,643)
			1,938		1,953
Other Property and Investments					
	Receivable from parent (less allowance for uncollectible accounts of $81 and $74)		-		-
	Nuclear decommissioning trust, at market value		31		30
	Non-qualified benefit plan trust		68		81
	Note receivable - Pelton Round Butte project sale		20		-
	Miscellaneous		28		35
			147		146

Current Assets				
	Cash and cash equivalents	51		8
	Accounts and notes receivable (less allowance for uncollectible accounts of $28 and $28)	241		272
	Contract termination receivable	-		28
	Unbilled and accrued revenues	84		80
	Assets from price risk management activities	77		170
	Inventories, at average cost	45		44
	Margin deposits	-		89
	Prepayments and other	90		78
	Deferred income taxes	3		6
		591		775
Deferred Charges				
	Unamortized regulatory assets	544		582
	Miscellaneous	30		18
		574		600
		$ 3,250		$ 3,474
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	488	451
Accumulated other comprehensive income (loss):		
Unrealized gain (loss) on derivatives classified as cash flow hedges	3	-
Minimum pension liability adjustment	(3)	(2)
Cumulative preferred stock subject to mandatory redemption	27	29
Limited voting junior preferred stock (Note 4)	-	-
Long-term obligations	827	769
	1,983	1,888
Commitments and Contingencies (Notes 7, 10-14, 16)		
Current Liabilities		
Long-term debt due within one year	191	173
Preferred stock maturing within one year	1	1
Short-term borrowings	-	174
Accounts payable and other accruals	244	250
Liabilities from price risk management activities	80	196
Customer deposits	5	5
Accrued interest	15	13
Dividends payable	1	1
Accrued taxes	22	15
Unamortized regulatory liabilities	-	42
	559	870
Other		
Deferred income taxes	383	339

Deferred investment tax credits	20		23
Trojan decommissioning and transition costs	186		205
Unamortized regulatory liabilities	16		44
Non-qualified benefit plan liabilities	59		62
Miscellaneous	44		43
	708		716
	$ 3,250		$ 3,474

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

Portland General Electric Company and Subsidiaries

Consolidated Statements of Cash Flows

For the Years Ended December 31	2002	2001	2000
	(In Millions)		
Cash Flows From Operating Activities:			
Reconciliation of net income to net cash provided by (used in) operating activities			
Net income	$ 66	$ 34	$ 141
Non-cash items included in net income:			
Cumulative effect of a change in accounting principle,			
net of tax	-	(11)	-
Depreciation and amortization	161	170	164
Deferred income taxes	55	(31)	(8)
Net assets from price risk management activities	(11)	30	(13)

Power cost adjustment	(19)	(89)	-
Provision for uncollectible accounts receivable from affiliates	6	79	-
Other non-cash income and expenses (net)	(17)	27	36
Changes in working capital:			
Net margin deposit activity	89	(223)	139
(Increase) Decrease in receivables	6	(10)	(158)
Increase (Decrease) in payables	1	(30)	118
Other working capital items - net	(23)	(29)	(14)
Other - net	(16)	16	18
Net Cash Provided by (Used in) Operating Activities	298	(67)	423
Cash Flows From Investing Activities:			
Capital expenditures	(165)	(203)	(173)
Proceeds from sales of assets	-	-	27
Other - net	12	10	(1)
Net Cash Used in Investing Activities	(153)	(193)	(147)
Cash Flows From Financing Activities:			
Net Increase (Decrease) in short-term borrowings	(174)	158	(250)
Repayment of long-term debt	(174)	(58)	(33)
Issuance of long-term debt	250	150	150
Preferred stock retired	(2)	-	-
Dividends paid	(2)	(42)	(83)

Net Cash Provided by (Used in) Financing Activities		(102)		208		(216)
Increase (Decrease) in Cash and Cash Equivalents		43		(52)		60
Cash and Cash Equivalents, Beginning of Period		8		60		-
Cash and Cash Equivalents, End of Period		$ 51		$ 8		$ 60
Supplemental disclosures of cash flow information						
Cash paid during the period:						
Interest, net of amounts capitalized		$ 62		$ 66		$ 62
Income taxes		2		35		109
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 PGE, merged with 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 covers 3,150 square miles. It includes 51 incorporated cities, of which Portland and Salem are the largest, within a state-approved service area allocation of 4,095 square miles. At the end of 2002, PGE's service area population was approximately 1.5 million, comprising about 44% of the state's population. The Company served approximately 743,000 retail customers at December 31, 2002.

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. 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. 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 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.

Emerging Issues Task Force Issue No. 02-3 (EITF 02-3), Accounting for Contracts Involved in Energy Trading and Risk Management Activities, which became effective in the third quarter of 2002, requires that unrealized and realized gains and losses associated with "energy trading activities" be reported on a net basis. Accordingly, PGE now records unrealized and realized gains and losses from trading activities on a net basis as a component of Operating Revenues. Previously, unrealized gains and losses from trading activities were recorded on a net basis in Purchased power and fuel; when such contracts were settled, sales were recorded in Operating Revenues and purchases were recorded in Purchased power and fuel. In accordance with requirements of EITF 02-3, all amounts in comparative financial statements for prior periods have been reclassified to conform to the new presentation. Such reclassification, which had no effect on margins from energy sales, resulted in $627 million and $366 million reductions to both Operating Revenues and Purchased power and fuel expense for 2001 and 2000, respectively.

As a result of this reclassification, PGE's financial statements were re-audited for the year 2000. Although Arthur Andersen LLP previously audited PGE's 2000 financial statements, the Company's current independent accountants, PricewaterhouseCoopers LLP, performed the re-audit as Arthur Andersen LLP no longer provides audit services.

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

Purchased Power

PGE and 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 mechanisms, as well as amortization of such amounts as recovery is made from customers, are also reflected within Purchased power and fuel expense.

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.

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

	2002		2001
Production	$1,347		$1,367
Transmission	349		350
Distribution	1,577		1,487
General	238		228
Intangible	114		67
Construction Work in Progress	81		97
Total	$3,706		$3,596

Depreciation and Amortization

Depreciation is computed using the straight-line method over the estimated average service lives of various classes of plant in service. It is based upon original cost and includes an estimate of expected salvage, less the cost of asset removal. Classes of plant in service and their estimated service lives (in years) are as follows: Production (31), Transmission (39), Distribution (33), and General (14). Depreciation expense as a percent of the related average depreciable plant in service was approximately 4.4% in 2002 and 4.2% in 2001 and 2000.

Periodic depreciation studies are conducted to update depreciation parameters (i.e. retirement dispersion patterns, average service lives, and net salvage rates). 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 together with cost of removal (net of salvage), is charged to accumulated depreciation when property is retired and removed from service.

Intangible plant, primarily computer software development costs, is amortized over estimated average service lives. Amortization expense for 2002, 2001, and 2000 was $8 million, $6 million, and $6 million, respectively, and is estimated at $12 million annually for the period 2003 through 2007. Accumulated amortization was $46 million and $41 million at December 31, 2002 and December 31, 2001, 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 2002, 2001, and 2000 were 5.0%, 6.0%, and 6.8%, respectively. AFDC from borrowed funds was $3 million in 2002, 2001 and 2000. AFDC from equity funds was $2 million in 2002, $3 million in 2001, and $0 in 2000.

Debt Issuance Costs

Underwriting, legal and other direct costs incurred in connection with 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, 2002 and 2001 were $21 million and $9 million, respectively, and are classified within "Deferred charges - miscellaneous" on the Balance Sheet. The December 31, 2002 balance includes a $12 million cost for a policy insuring principal and interest payments on $100 million of 5.6675% First Mortgage Bonds issued in October 2002.

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. 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 12, 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.

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 and option, natural gas forward, swap and futures contracts, and crude oil futures contracts. Prior to 2001, trading contracts were accounted for as prescribed by EITF 98-10, Accounting for Energy Trading and Risk Management Activities. 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.

Non-Trading

Non-trading electricity and natural gas forward contracts and electricity options that are entered into in anticipation of serving the Company's regulated retail load generally meet the requirements for treatment under the normal purchases and normal sales exception under SFAS No. 133. Other non-trading activities consist of certain natural gas forwards and swaps that qualify as cash flow hedges of forecasted transactions, and certain natural gas swaps along with forward contracts for acquiring Canadian dollars are classified as non-hedges. Such activities are intended to protect against variability in expected future cash flows due to associated price risk and are utilized to manage overall fuel costs for retail customers.

PGE's electric retail business is subject to OPUC regulation. The OPUC recognizes non-trading contracts only at the time of settlement. Contracts that qualify for the normal purchases and normal sales exception are not required to be recorded at fair value. Unrealized gains and losses from contracts that qualify as cash flow hedges are recorded net in Other Comprehensive Income (OCI) and contracts not designated as hedges are recorded net in purchased power and fuel on the Statement of Income. To reflect the effect of regulation, PGE records a regulatory asset or regulatory liability under SFAS No. 71, Accounting for the Effects of Certain Types of Regulation, to offset unrealized gains and losses on certain non-trading contracts recorded prior to settlement. The regulatory asset or regulatory liability is reflected as Unamortized regulatory assets or Unamortized regulatory liabilities, respectively, on the Balance Sheet. Upon settlement, the regulatory asset or regulatory liability is reversed. Due to performance risk and credit risk of the parties to each contract, sales are recorded in Operating revenues and purchases are recorded in Purchased power and fuel on the Statement of Income.

Trading

For energy trading activities, EITF 02-3, Accounting for Contracts Involved in Energy Trading and Risk Management Activities, which became effective in the third quarter of 2002, requires that all unrealized and realized gains and losses associated with "energy trading activities" be reported on a net basis for all periods presented. PGE records unrealized and realized gains and losses from trading activities on a net basis as a component of Operating revenues on the Statement of Income. Amounts for periods prior to 2002 have been reclassified to conform to the new presentation.

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

Cash and Cash Equivalents

Highly liquid investments with original maturities of three months or less are classified as cash equivalents.

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.

Non-Qualified Benefit Plan Trust

The non-qualified benefit plan trust (rabbi trust) is comprised of insurance contracts and cash. 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 $58 million at December 31, 2002 and $81 million at December 31, 2001. Trust cash balances were $10 million at December 31, 2002 and $0 at December 31, 2001.

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):

	2002		2001
Coal	$ 5		$ 5
Fuel oil	14		14
Natural gas	1		-
Materials and supplies	23		23

Unallocated stores account	2		2
Total	$45		$44

-

Trojan Decommissioning and Transition Costs

Trojan decommissioning costs consist of those expenditures related to the decommissioning of the plant, as well as certain transition costs associated with operating and maintaining the spent fuel pool and securing the plant until fuel is transferred to dry storage. Estimates of future expenditures are reflected as a liability on the Balance Sheet, with actual expenditures charged to the liability account as incurred. Estimated future expenditures are revised periodically and are stated in nominal dollars. See Note 11, 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 Current assets and Current liabilities, Deferred charges, and Other liabilities on the Balance Sheet and are amortized over the period in which they are included in billings to customers.

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

		2002		2001
Unamortized regulatory assets:				
	Trojan decommissioning costs	$158		$172
	Income taxes recoverable	116		127
	Prior tax benefits recoverable	28		37
	Debt reacquisition costs	18		20
	Conservation investments - secured	38		46
	Energy efficiency programs	31		35
	Power cost adjustment	109		89
	Price risk management	11		28
	Regulatory restructuring costs	20		14

	Miscellaneous	15		14
	Total	$544		$582
Unamortized regulatory liabilities:				
	NEIL distribution	$ -		$ 21
	Merger savings obligation	-		8
	Price risk management	7		-
	Information technology costs	6		-
	Miscellaneous	3		15
	Subtotal	16		44
	Deferred energy revenues (current)	-		42
	Total	$ 16		$ 86

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 allows 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.

Conservation investments-secured

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

Energy efficiency programs -

PGE's energy efficiency program expenditures, formerly deferred and amortized, have been expensed directly since October 1, 2000. The unamortized balance of those expenditures incurred prior to October 1, 2000, as well as amounts recoverable under the Company's SAVE energy efficiency program and certain other energy efficiency costs, have been combined within a single regulatory asset account. Beginning October 1, 2001, amounts are recovered from retail customers by a separate supplemental tariff schedule and amortized to expense over an approximate three-year period. 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 -

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 $73 million at December 31, 2002 and $89 at December 31, 2001 (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 balance, $36 million at December 31, 2002, is being recovered over a two-year period (one-year for large industrial customers) beginning January 1, 2003.

PGE currently has no power cost adjustment mechanism in place for 2003. The Company has, however, applied to the OPUC for the deferral, for later ratemaking treatment, increases in power costs related to adverse hydro conditions.

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, 2002 and 2001 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 $7 million is currently being recovered in rates charged to customers over a 6-year period. Application for recovery of the remaining $13 million in implementation costs has not yet been submitted to the Commission for consideration. The OPUC staff has recently completed an audit and prudency review of implementation costs, and in January 2003 issued a report that found these costs to be prudently incurred, with only minor adjustments proposed.

NEIL distribution

- In 2000, PGE received a distribution related to the termination of its membership in Nuclear Electric Insurance Limited (NEIL), with the customers' share deferred pending disposition by the OPUC. As authorized by the Commission, the balance was fully refunded in 2002.

Merger savings obligation

- As a condition of PGE's 1997 merger with Enron, retail customers were guaranteed $36 million in rate credits over a four-year period to reflect anticipated merger-related savings. In the Company's 2001 general rate proceeding, such savings were incorporated into operating expenses utilized to set new rates that became effective October 1, 2001. To reflect PGE's remaining liability for future customer credits, approximately $8 million was recorded as a regulatory liability at December 31, 2001; this amount was fully refunded during 2002.

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 retail customers are to receive a refund if the actual revenue requirements for such costs are less than the estimated revenue requirements. Accordingly, a regulatory liability of $8 million was recorded in 2002 to reflect the difference between actual and estimated revenue requirements related to CIS and IT capital expenditures; the balance at December 31, 2002 was $6 million. Customer refunds, which began in December 2002, are expected to be completed by the end of 2003. Differences between actual and estimated revenue requirements related to 2003 expenditures will likewise be recorded and subsequently refunded to retail customers.

Deferred energy revenues

- In PGE's 2001 general rate case, the OPUC authorized new electricity rates to cover forecast power costs that fluctuate materially due to market volatility. In order to properly match revenues and expenses, PGE deferred the difference between base energy revenues and base variable power costs over a 15-month test period utilized to determine the Company's authorized revenues. Beginning October 1, 2001, monthly differences were deferred and offset within Operating revenues, with deferred amounts fully recognized in 2002 revenues as expected power costs were incurred.

Other items

- As part of its August 2001 general rate order, the OPUC approved a supplemental tariff that refunded to retail customers the net unamortized balance of several regulatory liabilities and assets over an approximate one-year period beginning October 1, 2001. The largest of such items consisted of deferred gains on the sale of certain major assets and deferred Year 2000 remediation costs. The $8 million balance at December 31, 2001 (included within "Miscellaneous" regulatory liabilities) was fully refunded to customers in 2002.

Recovery/refund period -

As of December 31, 2002, the majority of the 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, within the next 9 years.

New Accounting Standards

SFAS No. 143, Accounting for Asset Retirement Obligations, requires the recognition of an Asset Retirement Obligation (ARO) for legal obligations related to the 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 those AROs that can be measured, 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. 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 income statement.

The Statement must be applied for fiscal years beginning after June 15, 2002. PGE has evaluated the impact of SFAS No. 143. The AROs have been identified with certain tangible long-lived assets, substantially all of which are included in rate-regulated operations. Pursuant to the regulatory process, the asset retirement cost of rate-regulated long-lived assets is included in depreciation expense allowed in rates. Substantially all the impact of adopting SFAS No. 143 on PGE's results of operations and financial condition is deferred by the application of SFAS No. 71, Accounting for the Effects of Certain Types of Regulation. As a result, the adoption of the accounting standard on January 1, 2003 is not expected to have a material impact on the Company's results of operations or financial condition.

SFAS No. 146, Accounting for Costs Associated with Exit or Disposal Activities, requires the recognition of a liability for costs related to exit or disposal activities when the costs are incurred. Previous accounting guidance required the liability to be recorded at the date of commitment to an exit or disposal plan. PGE is required to comply with SFAS No. 146 beginning January 1, 2003. Any future disposal will be accounted for under SFAS No. 146.

SFAS No. 148, Accounting for Stock-Based Compensation - Transition and Disclosure, provides two additional alternative transition methods for recognizing an entity's voluntary decision to change its method of accounting for stock-based employee compensation to the fair-value method. In addition, the new standard amends the requirements of SFAS No. 123, Accounting for Stock-Based Compensation, to require more prominent disclosures regarding pro forma effects of using the fair-value method of accounting for stock-based compensation and the presentation of such disclosures in a more accessible format in both annual and interim financial statement footnotes. SFAS No. 148 is effective for fiscal years ending after December 15, 2002. As PGE does not provide stock-based compensation to its employees, SFAS No. 148 has no effect on its financial statements.

The Company adopted Emerging Issues Task Force Issue No. 02-3 (EITF 02-3), Accounting for Contracts Involved in Energy Trading and Risk Management Activities, which became effective in the third quarter of 2002. EITF 02-3 requires that unrealized and realized gains and losses associated with "energy trading activities" be reported on a net basis. Accordingly, PGE now records unrealized and realized gains and losses from trading activities on a net basis as a component of Operating revenues. Previously, unrealized gains and losses from trading activities were recorded on a net basis in Purchased power and fuel; when such contracts were settled, sales were recorded in Operating revenues and purchases were recorded in Purchased power and fuel. In accordance with requirements of EITF 02-3, all amounts in comparative financial statements for prior periods have been reclassified to conform to the new presentation.

In October 2002, the Emerging Issues Task Force reached a consensus to rescind Issue 98-10 (EITF 98-10), Accounting for Energy Trading and Risk Management Activities, effective for fiscal periods beginning after December 15, 2002. With the rescission of EITF 98-10, only energy trading contracts that qualify as derivatives under SFAS No. 133 would be marked-to-market through earnings. This has no effect on PGE because all of the company's energy trading activities qualify as derivatives under SFAS No. 133.

FASB Interpretation No. 45 (FIN 45), Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Other, was issued in November 2002. FIN 45 contains requirements related to the guarantor's accounting for, and disclosure of, the issuance of certain types of guarantees. The disclosure requirements are effective for annual periods ending after December 15, 2002 and the provisions for initial recognition and measurement are effective on a prospective basis for guarantees that are issued or modified after December 31, 2002. PGE's guarantees are disclosed in Note 7, Commitments.

FASB Interpretation No. 46 (FIN 46), Consolidation of Variable Interest Entities, an interpretation of ARB No. 51, was issued on January 17, 2003. FIN 46 provides guidance on the identification and consolidation of entities (termed "variable interest entities") for which control is achieved through means other than through voting rights. FIN 46 also requires certain financial statement disclosures, some of which are immediately effective. PGE evaluated the impact of FIN 46 and determined that there were no material impacts related to its adoption by the Company.

Note 2 - Employee Benefits

Pension and Other Post-Retirement Plans

PGE participates in a non-contributory defined benefit pension plan with 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 primarily of trust owned life insurance policies (TOLI), are intended to be the primary source for financing these plans. Trust assets of $21 million and $22 million as of December 31, 2002 and 2001, respectively, are shown in the accompanying table for informational purposes only and are not considered segregated and restricted as defined by SFAS No. 87. In addition, the recognized losses on the TOLI assets of $1 million and $6 million for 2002 and 2001, respectively, are included in net periodic benefit cost.

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 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	
	2002	2001	2002	2001	2002	2001
Reconciliation of benefit obligation:						
Obligation at January 1	$306	$ 266	$ 19	$ 14	$ 35	$ 31
Service cost	9	9	-	-	1	1
Interest cost	21	20	2	1	3	2
Participants' contributions	-	-	-	-	1	1
Actuarial loss	32	28	-	5	5	3
Benefit payments	(15)	(17)	(2)	(1)	(3)	(3)

Obligation at December 31	$353	$ 306	$ 19	$ 19	$ 42	$ 35
Reconciliation of fair value of plan assets:						
Fair value of plan assets at January 1	$397	$ 424	$ 22	$ 29	$ 28	$ 30
Actual return (loss) on plan assets	(45)	(11)	(1)	(7)	(4)	-
Company contributions	-	-	2	1	-	-
Participants' contributions	-	-	-	-	1	1
Benefit payments	(15)	(16)	(2)	(1)	(3)	(3)
Fair value of plan assets at December 31	$337	$ 397	$ 21	$ 22	$ 22	$ 28
Funded status:						
Funded (unfunded) status at December 31 (*)	$(16)	$ 91	$ 2	$ 3	$ (20)	$ (7)
Unrecognized transition (asset)/liability	(4)	(5)	-	-	3	3
Unrecognized prior service cost	7	8	2	2	2	1
Unrecognized gain (loss)	81	(39)	1	3	12	1
Prepaid pension cost (liability)	$ 68	$ 55	$ 5	$ 8	$ (3)	$ (2)
Amounts recognized in the Balance Sheet						
consist of:						
Prepaid benefit cost	$ -	$ -	$ 8	$ 10	$ -	$ -

Accumulated other comprehensive income	-	-	(3)	(2)	-	-
Net amount recognized	$ -	$ -	$ 5	$ 8	$ -	$ -
Assumptions:						
Discount rate used to calculate benefit obligation	6.75%	7.25%	6.75%	7.25%	6.75%	7.25%
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	8.62%	9.50%
Components of net periodic benefit cost:						
Service cost	$ 9	$ 9	$ -	$ -	$ 1	$ 1
Interest cost on benefit obligation	21	20	2	1	3	2
Expected return on plan assets	(39)	(37)	-	-	(2)	(2)
Amortization of transition asset	(2)	(2)	-	-	-	-
Amortization of prior service cost	1	1	-	-	-	-
Recognized (gain) loss	(3)	(6)	1	8	-	-
Net periodic benefit cost (income)	$ (13)	$ (15)	$ 3	$ 9	$ 2	$ 1

(*) Due to the decline in the discount rate during 2002, 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 declined significantly, reflecting the general downturn in the equity markets. The impact of changing financial market conditions resulted in a total fair value of pension plan assets that was $16 million lower than the projected benefit obligation at December 31, 2002. However, the pension plan remains over-funded by $30 million with respect to the accumulated benefit obligation (the amount earned to-date by both current employees and retirees).

For measurement purposes, a 12.0% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2003. The rate was assumed to decrease to 5.0% 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	$0	$0
Effect on post-retirement benefit obligation	$1.0	$(0.9)

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 $45 million and $48 million at December 31, 2002 and 2001, 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 of $42 million and $56 million at December 31, 2002 and 2001, respectively, are intended to be the primary source for financing the MDCP Plan.

Retirement Savings Plan (401K)

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 continued for bargaining employees, in cash, under the union contract. Enron has indicated that it believes its existing equity has and will have no value and that any Chapter 11 plan of reorganization confirmed by the Bankruptcy Court will not provide its existing equity holders with any interest in the reorganized entity. 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. In 2002, PGE made matching contributions to its employees' savings plan accounts of approximately $10 million. 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.

All Employee Stock Option Plan

Enron stock options were granted to PGE employees on December 31, 1997 at the fair value of the stock at the date of the grant. As discussed above, shares of Enron common stock are no longer considered to have value. The Company has no stock option plans.

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):

		2002	2001	2000
Income Tax Expense				
Currently payable:				
	Federal	$ 5	$ 32	$ 88
	State and local	-	3	17
		5	35	105
Deferred income taxes:				
	Federal	46	(25)	(2)
	State and local	11	(5)	-
		57	(30)	(2)
Investment tax credit adjustments		(4)	(3)	(6)
Total income tax expense before cumulative				
	effect of a change in accounting principle	$ 58	$ 2	$ 97
Provision Allocated to:				
	Operations	$ 68	$ 38	$ 94
	Other income and	(10)	(36)	3

deductions			
Total income tax expense before cumulative			
effect of a change in accounting principle	$ 58	$ 2	$ 97
Effective Tax Rate Computation:			
Computed tax based on statutory federal			
income tax rate (35%) applied to income before			
before income taxes	$ 44	$ 9	$ 84
Flow through depreciation	8	5	6
State and local taxes - net of federal tax benefit	6	(1)	11
Investment tax credits	(4)	(3)	(6)
Excess deferred taxes	(1)	(1)	(1)
Deferred tax and other adjustments	5	(7)	3
Total income tax expense before cumulative			
	$ 58	$ 2	$ 97

	effect of a change in accounting principle				
Effective tax rate	46.8%			9.1% (*)	40.8%

(*) 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, 2002 and 2001, the significant components of PGE's deferred income tax assets and liabilities were as follows (in millions):

	2002	2001
Deferred income tax assets		
Depreciation and amortization	$ 18	$ 20
Employee benefits	8	11
Deferred energy revenue	-	17
Allowance for uncollectible accounts	10	10
Land reclamation costs	8	8
Regulatory liabilities		
NEIL distribution	-	8
Miscellaneous	1	8
Other	14	11
Total deferred income tax assets	59	93
Deferred income tax liabilities		

Depreciation and amortization	328	323
Receivable from parent	3	4
Price risk management	1	1
Regulatory assets		
Prior tax benefits recoverable	11	14
Debt reacquisition costs	7	8
Conservation investments	14	16
Energy efficiency programs	6	9
Power cost adjustment	43	35
Miscellaneous	16	7
Other	10	9
Total deferred income tax liabilities	439	426
Net deferred income taxes	$380	$333
Classification of net deferred income taxes		
Included in current assets	$ 3	$ 6
Included in non current liabilities	383	339
Net deferred income taxes	$380	$333

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

Note 4 - Common and Preferred Stock

Common Stock	Cumulative Preferred	Limited Voting Junior Preferred
Number of Shares		