UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 8-K

CURRENT REPORT

PURSUANT TO SECTION 13 OR 15(d) OF THE

SECURITIES EXCHANGE ACT OF 1934

Date of Report (Date of earliest event reported) February 22, 2001

PORTLAND GENERAL ELECTRIC COMPANY

(Exact name of registrant as specified in its charter)

Oregon	**1-5532-99**	**93-0256820**
(State or other jurisdiction of incorporation or organization)	Commission File Number	(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**

Item 5. Other Event

Management's Discussion and Analysis of

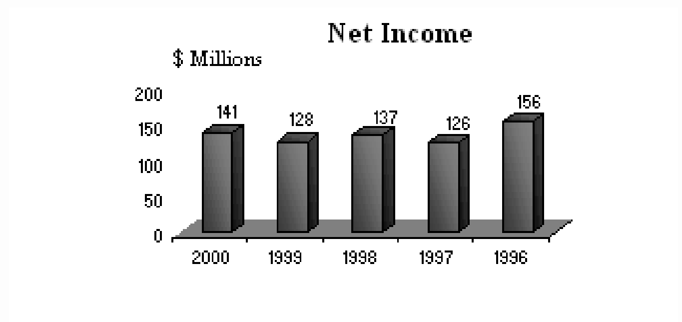
Financial Condition and Results of Operations

Results of Operations

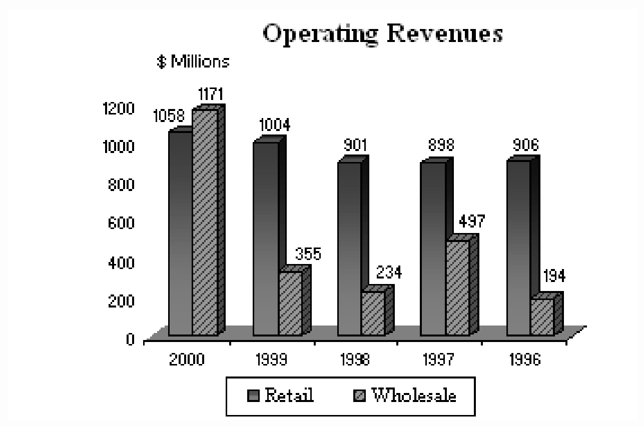
General

2000 Compared to 1999

Net income in 2000 increased to $141 million from $128 million in 1999 as a result of higher margins on energy sales. Such higher margins were partially offset by increased operating expenses during the year.

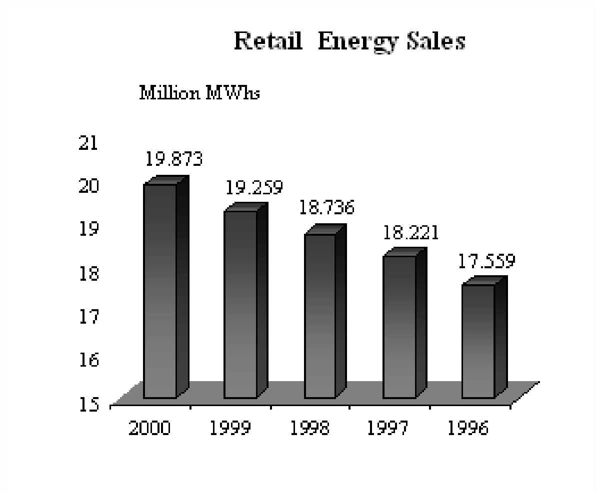


Total operating revenues increased $875 million (63%) primarily due to a significant increase in the price of energy sold in the wholesale market. The price increase was the result of various conditions, including higher natural gas prices, reduced hydro conditions, and increased regional demand. Wholesale revenues increased $816 million (from $355 million to $1,171 million), as Portland General Electric Company (PGE or the Company) sold on the wholesale market excess power purchases; wholesale energy sales increased 47% at average prices that increased 124% due to higher power prices. PGE entered into power and gas purchase contracts in anticipation of higher retail demand in 2000. However, due to mild temperatures, such demand was lower than expected and the Company was able to economically sell its excess power and gas in the wholesale market.



Retail revenues increased $54 million as large paper, chemical, high tech, and metals manufacturers increased their energy use; prices averaged 3% higher than last year due to higher prices for customers whose power prices were indexed to the market price of power. Total retail energy sales increased 3% as higher sales to industrial customers were partially offset by flat residential sales caused by warmer weather during the first half of the year. Total retail customers increased by about 5,900 (1%) from the end of last year; such increase includes the offsetting effect of the loss of approximately 7,150 customers who were transferred to two public utility districts upon the sale of a portion of PGE's service territory (for further information, see "Asset Sales" in the Financial and Operating Outlook section). Other operating revenues increased $5 million (26%) due largely to increased sales of natural gas in excess of generation requirements.

Purchased power and fuel costs increased $807 million (123%) due to significantly higher power prices and higher wholesale load. The average cost of firm and secondary power purchases doubled due to higher regional power and gas market prices. Combined with a 25% increase in power purchases, increased combustion turbine generation, and reduced hydro production, PGE's average variable power cost increased 86%. Partially offsetting the cost of purchased power and fuel was an approximate $13 million unrealized net gain on electricity trading contracts and natural gas swaps recorded during the year (see Note 8, Price Risk Management, in the Notes to Financial Statements for further information). In addition, PGE's Electricity Exchange pilot program, by which certain large commercial and industrial customers can voluntarily reduce their electricity usage during certain peak periods in exchange for energy credit payments, contributed to a reduction in the Company's net variable power costs during the second half of the year.



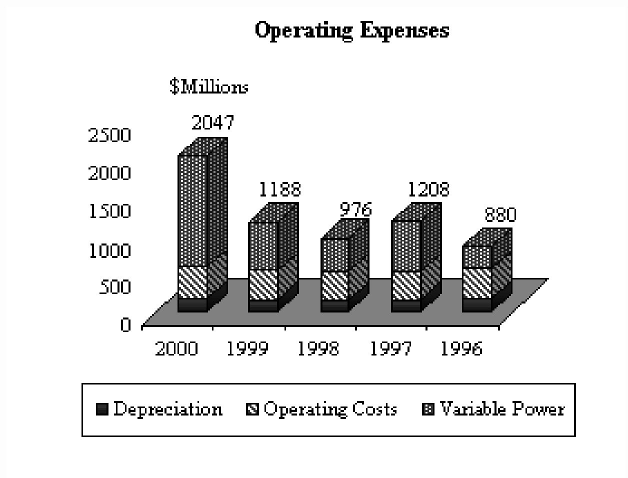
Company generation increased 9%, with a 69% increase in combustion turbine plant generation partially offset by reduced coal-fired and hydro production. Total generation met approximately 54% of PGE's retail load during the year, compared to 51% last year.

Megawatt-Hours/Variable Power Costs

	Megawatt-Hours (thousands)		Average Variable Power Cost (Mills/KWh)	
	2000	1999	2000	1999
Generation	11,430	10,515	14.5	11.3
Firm Purchases	25,049	18,897	34.9	23.2
Spot Purchases	3,258	3,712	123.6	19.7
Total Send-Out	39,737	33,124	37.2*	20.0*

(* includes wheeling costs)

Operating expenses (excluding purchased power and fuel, depreciation and taxes) increased $29 million (12%) as administrative, customer support, and fixed plant and delivery system costs all experienced increases from the prior year. Expenses last year were reduced by the effect of a non-recurring reduction in employee benefit accruals resulting from negotiated changes to union pension and Retirement Savings Plan enhancements. In 2000, the Company recorded a $2 million provision against deferred costs related to the proposed sale of its 20% interest in Units 3 and 4 of the Colstrip power plant. The sale was denied by the Oregon Public Utility Commission (OPUC), and in its recently filed restructuring plan, the Company seeks rate recovery of certain costs associated with this proposed sale. Other increases include approximately $5 million in maintenance and overhaul activities at the Boardman and Colstrip coal plants, $4 million in employee health insurance costs and insurance claim provisions, and $2 million in development expenditures related to the Company's customer information system. Beginning October 1, 2000, energy efficiency program expenditures, previously deferred and amortized over a five-year period, are charged to current operations, resulting in a $2 million increase in operating expenses. In addition, a $2 million contract termination settlement with an Oregon electric cooperative was



recorded in 2000; this amount was deferred, in accordance with an accounting order from the OPUC, and offset within Depreciation and amortization expense.

Depreciation and amortization expense increased $9 million (6%) due to both a net increase in regulatory amortization and to normal capital additions. The increase in regulatory amortization was primarily attributable to the accounting effect of settlement agreements between PGE, the OPUC, and the Citizens' Utility Board (CUB) related to the Company's investment in the closed Trojan nuclear plant (see Note 10, Legal Matters, in the Notes to Financial Statements for further information).

Taxes other than income taxes increased $4 million (7%) due primarily to increased payroll taxes. Income taxes increased $10 million (12%) primarily because of the increase in taxable operating income.

Other Income remained the same as last year. During 2000, the Company wrote off its remaining $5 million investment in the Trojan plant as part of a settlement (discussed above) and incurred a $1 million loss in the value of trust owned life insurance, compared to an $11 million gain in 1999. These were largely offset by PGE's $15 million share of a distribution received in connection with the termination of the Company's membership in Nuclear Electric Insurance Limited (NEIL).

Interest charges increased $3 million (4%), caused primarily by the replacement of short-term debt with higher interest long-term debt, as $150 million of 7.875% unsecured notes were issued in March 2000.

1999 Compared to 1998

Portland General Electric's net income for 1999 was $128 million compared to $137 million for 1998. Increased property, franchise, and income taxes, as well as a reduction from 1998's gains on the sale of Company land, were primarily responsible for the decrease. These were partially offset by an increased margin on higher electricity sales and by reduced interest charges.

Retail revenues increased $103 million primarily due to higher energy sales resulting from both the addition of 15,000 new customers as well as the termination of 1998's Customer Choice pilot program which enabled participating customers to purchase their electricity from other energy service providers. Revenues from power delivery services to energy service providers totaled $21 million in 1998; termination of the pilot program in 1999 caused the decrease in Other operating revenues.

Wholesale revenues increased $121 million (52%) due to both higher energy sales volume and prices. Increased energy sales resulted largely from sales in the wholesale market of excess power obtained to meet higher anticipated retail demand. Demand was lower than expected due to mild temperatures in 1999.

Purchased power and fuel costs increased $199 million (44%) due to higher prices for increased energy purchases. Higher regional power and gas market prices increased the cost of firm power purchases, resulting in a 25% increase in average power prices. Purchases were made to supply expected higher retail demand caused by weather volatility and customer growth, including the return of those customers participating in 1998's Customer Choice pilot program. Increased purchases also reflected PGE's ability to purchase power at a price more economical than generation. Company generation decreased from 37% to 32% of total power needs, primarily due to the economic displacement of gas powered generation, which declined about 21%. Coal and hydro generation in 1999 approximated that of 1998.

Operating expenses (excluding purchased power and fuel, depreciation and taxes) remained about the same as in 1998, as increased administrative and delivery system costs were offset by reduced generating plant expenses.

Depreciation and amortization expense increased $6 million (4%) primarily due to the effect of 1998's non-recurring $4 million gain on the sale of land formerly occupied by PGE's Western Division offices.

Taxes other than income taxes increased $4 million (7%) primarily due to higher state property taxes, caused by increases in taxable values, and city franchise fees that increased with higher electricity sales. Income taxes increased $3 million (4%) primarily because of the reversal of pre-1981 tax benefits related to the depreciation of certain regulatory assets; this was partially offset by a small decrease in net taxable income for the year.

Interest charges decreased $6 million (8%) due to a reduction in outstanding debt.

Cash Flow

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.

PGE maintains varying levels of short-term debt, primarily in the form of commercial paper, which serves as the primary form of daily liquidity. In 2000, monthly balances ranged from $16 million to $278 million. PGE has two committed borrowing facilities: a

$150 million facility maturing in July 2003 and a $100 million facility maturing in July 2001. Both facilities are used as backup for PGE's commercial paper facility.

A significant portion of cash provided by operations comes from 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 $424 million in 2000, compared to $238 million in 1999. The increase is due primarily to the receipt of $134 million in deposits from wholesale electricity customers and from an increase in accounts payable to power suppliers, both reflected in the year's increase in accounts payable. This was partially offset by an increase in accounts receivable from wholesale electricity customers. Increased "Other non-cash income and expenses (net)" was due largely to the effect of reductions in customer refunds related to Oregon excise taxes and to customer savings under the Company's energy efficiency programs. Reflected in the change from last year's "Other working capital items" were reduced fuel and material inventory purchases in 2000. Included in "Other - net" is a $19 million accrual for the refund to customers of a termination distribution received from NEIL and a $12 million reduction from 1999 expenditures for maintenance and overhaul activities at the Company's Coyote Springs combustion turbine generating plant.

Investing Activities consist primarily of improvements to PGE's distribution, transmission, and generation facilities. Capital expenditures of $173 million in 2000 were primarily for the expansion and upgrade of PGE's distribution system. In 1999, capital expenditures of $182 million included the $37 million purchase of six combustion turbine generators at the Beaver generating plant, previously operated under terms of a long-term lease. Proceeds from sales of assets consist primarily of amounts received from the sale of a portion of PGE service territory to two public utility districts and from the sale of the Company's interest in certain rights and facilities at its Coyote Springs combustion turbine generating plant (for further information, see "Asset Sales" in the Financial and Operating Outlook section).

Capital expenditures are expected to approximate $186 million in 2001. Over the next few years, anticipated expenditures are expected to approximate current levels, with the majority of expenditures comprised of improvements to the Company's expanding distribution system to support both new and existing customers within PGE's service territory.

Financing Activities provide supplemental cash for day-to-day operations and capital requirements as needed. PGE relies on commercial paper borrowings and cash from operations to manage its day-to-day financing requirements. In 2000, PGE issued $150 million of 7.875% unsecured notes maturing in 2010 and, with approximately $100 million in deposits received from wholesale electricity customers, reduced its short-term commercial paper by $250 million. In addition, PGE repaid $25 million in matured First Mortgage Bonds; issuance expenses on the newly issued notes and payment of conservation bonds, totaling $8 million, are also reflected in "Repayment of long-term debt".

In both 2000 and 1999, dividend payments totaled $83 million, consisting of $81 million in common stock dividends paid to its parent and $2 million in preferred stock dividends.

In July 1999, PGE received approval from the Federal Energy Regulatory Commission to issue short-term debt, including commercial paper, credit facilities, and other evidences of indebtedness up to $350 million. This approval is effective for two years and replaces and supercedes PGE's prior approval from the FERC authorizing short-term borrowing of $250 million. On July 27, 2000, PGE entered into a $250 million revolving credit facility with a group of commercial banks (see Note 5, Credit Facilities and Debt, in the Notes to Financial Statements for further information).

In November 1999, Standard & Poor's placed the ratings of the Company on CreditWatch Negative and Moody's Investors Services (Moody's) placed PGE's ratings, with the exception of Commercial Paper, on review for possible downgrade. Such actions were taken in response to the announced purchase and sale agreement of PGE to Sierra Pacific Resources and uncertainties surrounding the transaction. Standard & Poor's currently rates PGE's senior secured debt 'A', senior unsecured debt 'A-', preferred stock 'BBB+', and commercial paper 'A-1'. Moody's currently rates the Company's senior secured debt 'A2', senior unsecured debt 'A3', preferred stock 'a3', and commercial paper 'P-1'.

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 its First Mortgage Bonds. As of December 31, 2000, PGE has the capability to issue preferred stock and additional First Mortgage Bonds in amounts sufficient to meet its capital requirements.

Financial and Operating Outlook

Proposed Acquisition

On November 8, 1999, Enron announced that it had entered into a purchase and sale agreement to sell PGE to Sierra Pacific Resources (Sierra) for $2.1 billion, comprised of $2.02 billion in cash and the assumption of Enron's approximately $80 million merger payment obligation. The closing has been delayed by the effect of recent events in California and Nevada on the buyer.

On September 1, 2000, a merger settlement agreement was reached between PGE, OPUC staff, Sierra, the Citizens' Utility Board, and the Industrial Customers of Northwest Utilities. The agreement includes a six-year rate freeze on distribution, transmission, and customer service costs. The freeze does not affect PGE's ability to adjust prices in response to changing wholesale electricity and fuel costs; in addition, transmission rates may be adjusted to the extent that the Federal Energy Regulatory Commission (FERC) approves changes caused by implementation of a Regional Transmission Organization. In addition, the settlement agreement includes up to $97 million in customer rate credits to be paid over seven years, customer protections that guarantee a continued high level of service quality and reliability, and PGE's agreement to continue its leadership role and support of Oregon's electric restructuring legislation. On October 30, 2000, the OPUC approved Sierra's application to acquire PGE.

Receivables - California Wholesale Market

PGE has certain accounts receivable that may be affected by the financial condition of two major California utilities. Significant increases in wholesale power prices in 2000 and in early 2001, due in part to a sharp increase in natural gas prices paid by generators in producing electricity, have severely affected the financial stability of both companies. The utilities' recent wholesale power purchase costs have greatly exceeded revenues collected from customers through rates that are currently frozen, requiring the utilities to finance the majority of their power purchase costs. Adverse reaction of credit markets to continued regulatory uncertainty over the companies' ability to recover their power procurement costs has materially and adversely affected their liquidity (see Note 13, Receivables-California Wholesale Market, in the Notes to Financial Statements for further information).

Regulation and Competition

State

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 an open market competitive framework where customers have a choice of energy supplier. Federal laws and regulations now provide for open access to transmission systems and several states have adopted or are considering new regulations to allow open access for all energy suppliers.

In 1999, Oregon's governor signed into law State Senate Bill 1149 (SB1149) that provides all industrial and commercial customers of investor-owned utilities direct access to energy suppliers no later than October 1, 2001. Residential customers will be able to purchase electricity from a "portfolio" of rate options that will include a cost-of-service rate, a new renewable resource rate, and a market-based rate.

SB1149 also provides for a 10-year public purposes charge equal to 3% of retail revenues, designed to fund cost-effective conservation measures, new renewable energy resources, and weatherization measures for low-income housing. In addition, SB1149 provides for low-income electric bill assistance by affected utilities, which began in January 2000.

Also included in SB1149 is a requirement that investor-owned utilities unbundle the costs of service into power generation, transmission, distribution, and retail services. The law further provides for "transition" charges and credits that would allow recovery on prior uneconomic utility investment or a refund of benefits from prior economic utility investment. Utilities can propose incentives for the divestiture of generation assets, provided any divestiture does not deprive customers of the benefit of the utility's or the region's low cost resources. SB1149 further requires that its implementation have no material adverse impact on the ability of the affected investor-owned utilities to access cost-based power from the Bonneville Power Administration for its residential and small farm customers.

Following a series of issues discussion workshops and a formal rulemaking process, the Commission in September 2000 issued the first set of rules that provide a process for completing the steps necessary to move to direct access and protect all customer classes.

PGE filed its restructuring plan, including associated tariffs, with the OPUC on October 2, 2000. Such plan includes a request for increased revenues as well as rules and rate schedules that will allow the Company to implement direct access on October 1, 2001. As filed, the plan proposes a revenue requirement, based on a 2002 test year, of $1,452 million, an increase of $324 million over revenues derived from current base rates. The proposed increase in prices is largely attributable to higher wholesale electricity and natural gas fuel prices charged by PGE's suppliers; other factors include new facilities required to serve a growing number of customers, technology to meet customer service requirements, and rising labor costs. The increase to residential customers is expected to be partially offset by benefits from the Bonneville Power Administration. Business customers will have the option to purchase power on the open market. PGE remains subject to rate regulation and will continue to apply Financial Accounting Standards Board Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation", to reflect the effects of rate regulation in its financial statements.

In accordance with a March 17, 2000, rate order from the OPUC, PGE is deferring incremental costs of implementing SB1149 for recovery in future electricity rates; at December 31, 2000, such costs totaled approximately $4 million. In January 2001, the staff of the OPUC filed initial settlement proposals containing its positions and proposed adjustments regarding the Company's filed 2002 test year revenue requirements. PGE is currently considering a stipulation with OPUC staff which, if finalized, will settle many of the revenue requirement issues. PGE will continue to work with the OPUC staff and other parties in settlement discussions, with OPUC staff and intervenor testimony scheduled for filing on February 20, 2001.

In January 2001, the OPUC staff and PGE filed applications with the Commission for deferral of a portion of PGE's excess net variable power costs for 2001. PGE's application requests authorization to defer for later ratemaking treatment changes in net variable power costs, positive or negative, which differ from such costs approved by the Commission in the Company's last general rate case. This application and filing replaces a November 20, 2000 filing by PGE that sought a 16.5% average increase in electricity prices, effective January 1, 2001. This filing was withdrawn on December 22, 2000. On February 8, 2001, PGE stipulated to a power cost mechanism with OPUC staff and other parties that shares with retail customers any changes in PGE's power costs outside of a pre-determined range for the period January through September 2001. Such costs will be shared equally within certain limits, with 90% of costs in excess of such limits charged or credited to retail customers. On February 20, 2001, the OPUC consolidated the two applications and authorized PGE to defer, for future ratemaking treatment, any changes from a net variable power cost baseline amount of $176 million (for nine months). In a subsequent proceeding, PGE will request the recovery (or refund) of a portion of the deferred amount in accordance with the formula agreed to with OPUC staff on February 8, 2001. PGE's earnings for the nine month period will only reflect the expected recovery amount.

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, lower prices and more choices to wholesale energy customers.

Retail Customer Growth and Energy Sales

Weather adjusted retail energy sales increased 2.4% in 2000. Manufacturing sector energy sales increased 8.0% as large paper, chemical, high tech, and metals manufacturers significantly increased their energy use. Commercial sales growth remained strong at 2.2% over l999. Sales to residential customers, however, decreased 1.3% as average use declined and as approximately 6,000 residential customers were transferred to two public utility districts in the third quarter of the year, pursuant to the sale of a portion of PGE's service territory. PGE forecasts retail energy sales growth of approximately 2.5% in 2001.

Wholesale Sales

The decreasing surplus of electric generating capability in the western United States, the entrance of numerous wholesale marketers and brokers into the market, and open access transmission are contributing to increasing competitive pressure on the price of power. In addition, the development of financial markets, including the NYMEX electricity contract, has led to enhanced price discovery available for market participants, further adding to the pressure on wholesale prices and margins. During 2000, PGE's wholesale sales accounted for about 52% of total revenues and 48% of total energy sales. PGE will continue its participation 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.

Power & Fuel Supply

PGE's ability to purchase power in the wholesale market, along with its base of thermal and hydroelectric generating capacity, currently provides the Company the flexibility to respond to seasonal fluctuations in the demand for electricity both within its service territory and from its wholesale customers. However, surplus generation has diminished in recent years due to economic and population growth in the western United States; in addition, current uncertainty over restructuring deregulation has discouraged construction of new generating plants. Higher prices for natural gas, recent weather conditions in California and the Southwest, temporary closure of a number of generating plants due to maintenance and other related reasons, and fish protection flow limits affecting hydro generation, are expected to increase both price and demand pressure on available resources.

PGE has long-term power contracts with four hydro projects on the mid-Columbia River providing capability of approximately 650 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 Western Systems Coordinating Council should provide wholesale energy to supplement its generation and purchases under existing firm power contracts.

Early forecasts for 2001 indicate hydro conditions approximating only 63% of normal, compared to 92% of normal last year. 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. Additional factors that could affect the availability and price of purchased power 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.

PGE generated approximately 54% of its 2000 retail load requirement, compared to approximately 51% in 1999. Short-term and long-term purchases were utilized to meet the remaining load.

Restoration of Salmon Runs - 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 operations of hydroelectric projects on the Deschutes, Sandy, Clackamas, and Willamette Rivers.

Retail Competition

PGE operates within a state-approved service area and under current regulation is substantially free from direct retail competition with other electric utilities. PGE's competitors within its Oregon service territory include other fuel suppliers, such as the local natural gas company, which compete with PGE for the residential and commercial space and water heating market. In addition, there is the potential for the loss of PGE service territory from the creation of public utility districts or municipal utilities by voters.

An initiative petition was filed in February 2000 by a local political committee, which is attempting to amend the charter of the City of Portland to require the city's acquisition of privately owned electricity distribution systems and facilities within its boundaries under certain circumstances. The petition further provides that costs to purchase, condemn, or otherwise acquire such facilities be paid from the issuance of revenue bonds. If sufficient signatures are obtained (approximately 21,000), the proposed amendment would appear on the May 2002 ballot.

On March 20, 2000, PGE filed a complaint with the Multnomah County Circuit Court, asking the court to enjoin the city auditor from certifying the petition as a ballot measure on the grounds that the proposed amendment is unconstitutional under Oregon law. On October 30, 2000, the Court ruled against PGE in this matter. The Company has filed an appeal of this decision with the Oregon Court of Appeals.

Resource Plan

Under OPUC rules implementing Oregon's electric industry restructuring law, electric companies are required to file a Resource Plan proposing a disposition of their existing generating resources. Such disposition must facilitate a fully competitive market, provide consumers fair, non-discriminatory access to competitive markets, and retain the benefit of low-cost resources for customers.

On November 1, 2000, PGE filed with the OPUC its Resource Plan. Under the plan, PGE proposes to retain almost all of its resources, selling only its 20 percent share of Colstrip Units 3 and 4 in Montana. The plan also proposes that PGE's Coyote Springs combustion turbine generating plant be administratively valued and reclassified as an unregulated asset, with the Company retaining full ownership of the plant with the ability to sell its power within the western grid. All other generating resources would remain regulated, matching their output to the needs of PGE residential and small business customers. Following the Commission's review and public hearings, a decision by the OPUC on the Company's Resource Plan is anticipated by September 1, 2001.

Residential Exchange Program

The September 1998 Residential Exchange Termination Agreement with the Bonneville Power Administration provided approximately $35 million in BPA payments to PGE over two years, with benefits to PGE's residential and small farm customers continuing through the June 2001 termination of the agreement. At December 31, 2000, PGE had received the entire amount under the Agreement.

On October 31, 2000, PGE and BPA signed a Settlement Agreement that provides for BPA payments totaling $2.7 million, to be made from July through September of 2001; residential customer benefits will continue at the current rate through the end of this period. The Agreement further provides for additional residential exchange benefits, in the form of both cash payments and energy, over a ten-year period beginning October 1, 2001, with benefits continuing to pass directly to residential and small farm customers. The total amount of benefits will be determined based upon the outcome of BPA's current wholesale electric power and transmission rate proposals, approval of which is anticipated in 2001.

Asset Sales

In April 2000, upon approval by the OPUC and FERC, PGE sold 12% of its interest (representing a 10.5% tenancy-in-common share) in the Kelso-Beaver Pipeline to B-R Pipeline. PGE now owns approximately 79% of the pipeline, which directly connects its Beaver generating station to Northwest Pipeline, an interstate gas pipeline operating between British Columbia and New Mexico.

In July 2000, PGE sold its rights to build a combined cycle gas turbine power plant adjacent to its Coyote Springs 1 combustion turbine generating plant, along with 50% of its interest in the plants' common facilities, to Avista Corp. for approximately $14 million. Avista Corp. plans to build a 280-MW combined cycle gas turbine power plant on the site, which is scheduled for completion in June 2002. The new Coyote Springs 2 power plant will be owned by Avista Power LLC and operated by PGE under a 15-year operations and maintenance contract. The pre-tax gain on the sale, approximately $11 million, has been deferred for future refund to PGE customers.

In August 2000, following voter-approved condemnation and a settlement, PGE sold its service territory in four Columbia County cities to the Columbia River People's Utility District (CRPUD) and the Clatskanie Public Utility District (CPUD). After receiving approval from the OPUC, approximately 7,150 PGE customers were transferred to the two utility districts.

Hydro Relicensing

PGE Hydro - PGE's eight hydroelectric plants provide economical generation and flexible load following capabilities; in 2000, they produced 2.5 million MWh of renewable energy, about 13% of PGE's total retail customer load. The plants operate under federal licenses, which will be up for renewal between the years 2001 and 2006.

PGE's collaborative relicensing processes on the Willamette and Clackamas River hydroelectric projects are continuing. These projects are licensed until December 2004 and August 2006, respectively, and have a combined output of 181 MW. A significant number of biological, cultural, recreational, and engineering studies are being performed to determine the projects' impacts and opportunities for mitigation and enhancements. PGE's 22-MW Bull Run Project will not be relicensed when its existing federal license expires in November 2004.

During 2000, PGE resolved many of the outstanding issues associated with the relicensing of its 408-MW Pelton Round Butte Project on the Deschutes River, which provides about 20% of the Company's power-generating capacity. In April, PGE executed an agreement with the Confederated Tribes of Warm Springs (Tribes) that would result in shared ownership and control; PGE would continue to operate the project. Under terms of this agreement, the Tribes will acquire an increasing share of the project starting in January 2002, when it will purchase a one-third interest at the net depreciated book value on December 31, 2001. The settlement, which was approved by the OPUC in August 2000, will replace the fees PGE had been paying the Tribes for the inundation of their property along the Deschutes and Metolius River. PGE and the Tribes completed the draft of their joint 50-year license application in 2000, and anticipate filing the final application with the FERC in the spring of 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. Certain Idaho Electric Utility Co-operatives have initiated proceedings with the FERC seeking to change the allocation of generation from the Priest Rapids and Wanapum dams between electric utilities in the region upon expiration of the current contracts. In early 1998, the FERC ruled that the portion of the output from these dams made available to purchasers such as PGE be reduced to 30%, and that such purchases be at market-based rather than cost-based prices. This decision could change both PGE's percentage share and the price of power from these facilities, although such changes are not yet determinable.

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.

Trojan Investment Recovery

Due to the closure of PGE's 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. See Note 10, Legal Matters, in the Notes to Financial Statements for further information.

Nuclear Decommissioning

PGE currently estimates the total cost to decommission Trojan at $337 million (nominal dollars), with approximately $140 million expended through 2000. The total estimate assumes that the majority of decommissioning activities will be completed after the spent fuel has been transferred to a temporary dry spent fuel storage facility in 2003. The plan anticipates final site restoration activities will begin in 2018 after PGE completes shipment of spent fuel to a United States Department of Energy (USDOE) facility. See Note 11, Trojan Nuclear Plant, in the Notes to Financial Statements for further information.

Environmental Matter

A 1997 investigation of a portion of the Willamette River known as the Portland Harbor, conducted by the U.S. Environmental Protection Agency (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").

The Oregon Department of Environmental Quality (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 harbor sediments. While PGE does not believe that it is responsible for any contamination in Portland Harbor, the Company voluntarily completed on site testing and submitted a work plan for DEQ review and approval. Investigations of the site by PGE have shown no significant soil or groundwater contaminations with a pathway to the river sediments from the Harborton site. Remedial activities, if any, that PGE may ultimately perform with respect to this matter will depend on the results of further investigations.

PGE does not expect environmental matters to have a material adverse impact on the financial condition or results of operations of the Company.

RTO West and Proposed Independent Transmission Company

In December 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 plans for the formation of Regional Transmission Organizations (RTOs), to be implemented by December 15, 2001.

In response to this order, nine western utilities, including PGE and BPA, on October 22, 2000 filed an initial plan with the FERC to form RTO West, a regional non-profit transmission organization that would operate the transmission system in the Pacific Northwest, Nevada, and parts of neighboring states.

In addition, PGE and five other regional utilities filed a proposal with the FERC to form an independent transmission company (ITC), to be called TransConnect. The new company would participate in RTO West and as a transmission owner would own or lease the high voltage transmission systems of the member companies. TransConnect would be formed as a for-profit transmission company meeting the independence criteria established by FERC for RTOs. As such, PGE believes TransConnect would enhance the efficiency and reliability of RTO West, as well as more quickly implement the RTO's decisions and simplify ratemaking. Because it would be a relatively large for-profit business, it could more readily raise capital for system improvements and expansion, easing congestion and further enhancing reliability.

The proposal, filed on October 15, 2000, is also subject to approval by state regulators and the board of directors of each filing company. It is currently anticipated that RTO West and TransConnect will begin operations no earlier than December 2001.

New Accounting Standard

In June 1998, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities". The Statement establishes accounting and reporting standards requiring that every derivative instrument be recorded on the balance sheet as either an asset or liability measured at its fair value. The Statement requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows a derivative's gains and losses to offset related results on the hedged item in the income statement, and requires that a company must formally document, designate, and assess the effectiveness of transactions that receive hedge accounting.

SFAS No. 133 is effective for fiscal years beginning after June 15, 2000, and must be applied to (a) derivative instruments and (b) certain derivative instruments embedded in hybrid contracts that were issued, acquired or substantively modified after December 31, 1998 (effective dates noted are as amended by SFAS No. 137). In June 2000, the FASB issued SFAS No. 138, which amended certain guidance within SFAS No. 133.

PGE has evaluated the impact of SFAS 133, as amended, and adopted it on January 1, 2001. The derivative instruments identified were primarily, in the Company's evaluation, subject to the normal purchases and normal sales exception (see FASB issue below) with some as hedges of forecasted transactions and no hedging designation. The Company expects the transition adjustment upon adoption of SFAS 133 will be approximately an $11 million gain, net of tax, from a cumulative effect of a change in accounting principle, and about a $35 million increase, net of tax, in Other Comprehensive Income, a component of shareholders' equity, as of the effective date.

The impact of adoption, however, is dependent upon certain pending interpretations of the statement related to the application of the normal purchases and normal sales exception (i.e. electric utility's practice of "bookouts" and "net scheduling" of power contracts). For purposes of determining the impact upon adoption, the Company has elected to treat under the normal purchases and normal sales exception certain contracts for the purchase and sale of electricity that may be booked out or net scheduled. The interpretation of this issue is currently under consideration by the Derivatives Implementation Group and the FASB. Given the uncertainties of this issue, the Company cannot predict the ultimate outcome at this time. If the FASB ultimately rules that bookouts and net scheduling meet the net settlement provisions, then the affected power contracts would not qualify for the normal purchases and normal sales exception and would be required to be fair valued pursuant to SFAS No. 133. This may cause the amounts stated above and the relative impact to PGE's financial statements, to be materially different. However, pursuant to the regulatory process, the Company believes that any required revision that may impact PGE's results of operations and financial condition, would be mitigated by the application of SFAS 71, Accounting for the Effects of Certain Types of Regulation.

Information Regarding Forward-Looking Statements

This report includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Although PGE believes that its expectations are based on reasonable assumptions, it can give no assurance that its expectations will be achieved. Important factors that could cause actual results to differ materially from those in the forward-looking statements herein include political developments affecting federal and state regulatory agencies, the pace of electric industry deregulation in Oregon and in the United States, environmental regulations, changes in the cost of power, and adverse weather conditions during the periods covered by the forward-looking statements.

Quantitative and Qualitative Disclosures About Market Risk

PGE's primary business is to serve 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. 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 instruments that reduce commodity price risks are recognized in purchased power and fuel expense, or in wholesale revenue. In addition, Company policy allows the use of these instruments for trading purposes in support of its operations; gains or losses on such instruments are recognized within "Purchased power and fuel" expense on PGE's Income Statement.

The use of derivative commodity instruments may expose the Company to market risks resulting from adverse changes in commodity prices; the Company actively manages this risk to ensure compliance with its risk management policies. Market risks associated with commodity derivatives held at December 31, 1999, were not material. In 2000, PGE's market risk profile changed because of increased volatility in electricity and natural gas prices. However, due to continuing low trading limits and volumes, the Company has maintained a limited exposure to market movements. The Company is subject to limits on open commodity positions and monitors this using a value at risk methodology, which measures the potential impact of market movements over a given time interval. Value at risk remains at an immaterial level at December 31, 2000.

In addition, PGE is exposed to risk resulting from changes in interest rates as a result of its issuance of variable rate commercial paper. Although the Company currently has no financial instruments to mitigate such risk, it will consider such instruments in the future as necessary.

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.

Financial Statements and Supplementary Data

Management's Responsibility for Financial Reporting

The following financial statements of Portland General Electric Company and subsidiaries (collectively, PGE) were prepared by management, which is responsible for their integrity and objectivity. The statements have been prepared in conformity with accounting principles generally accepted in the United States 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 assessed its internal control system as of December 31, 2000, 1999 and 1998, relative to current standards of control criteria. Based upon this assessment, management believes that its system of internal controls was adequate during the periods to provide reasonable assurance as to the reliability of financial statements and the protection of assets against unauthorized acquisition, use or disposition.

Arthur Andersen LLP was engaged to audit the financial statements of PGE and issue reports 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 opinion on the financial statements. Arthur Andersen LLP was also engaged to examine and report on management's assertion about the effectiveness of PGE's system of internal controls over financial reporting and the protection of assets against unauthorized acquisition, use or disposition. The Reports of Independent Public Accountants appear in this report.

The adequacy of PGE's financial controls and the accounting principles employed in financial reporting are under the general oversight of the Audit Committee of Enron's Board of Directors. No member of this committee is an officer or employee of Enron or PGE. The independent public 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 Public Accountants

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

We have examined management's assertion that the system of internal control of Portland General Electric Company and its subsidiaries as of December 31, 2000, 1999 and 1998 was adequate to provide reasonable assurance as to the reliability of financial statements and the protection of assets against unauthorized acquisition, use or disposition, included in the accompanying report on Management's Responsibility for Financial Reporting. Management is responsible for maintaining effective internal control over the reliability of the financial statements and the protection of assets against unauthorized acquisition, use or disposition. Our responsibility is to express an opinion on management's assertion based on our examination.

Our examination was made in accordance with standards established by the American Institute of Certified Public Accountants and, accordingly, included obtaining an understanding of the system of internal control over financial reporting and the protection of assets against unauthorized acquisition, use or disposition, testing and evaluating the design and operating effectiveness of the system of internal control and such other procedures as we considered necessary in the circumstances. We believe that our examination provides a reasonable basis for our opinion.

Because of inherent limitations in any system of internal control, errors or irregularities may occur and not be detected. Also, projections of any evaluation of the system of internal control to future periods are subject to the risk that the system of internal control may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assertion that the system of internal control of Portland General Electric Company and its subsidiaries as of December 31, 2000, 1999, and 1998 was adequate to provide reasonable assurance as to the reliability of financial statements and the protection of assets against unauthorized acquisition, use or disposition is fairly stated, in all material respects, based upon current standards of control criteria.

Arthur Andersen LLP

Portland, Oregon

January 26, 2001

Report of Independent Public Accountants

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

We have audited the accompanying consolidated balance sheets of Portland General Electric Company (an Oregon corporation), and subsidiaries as of December 31, 2000 and 1999, and the related consolidated statements of income, retained earnings and cash flow for each of the three years in the period ended December 31, 2000. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Portland General Electric Company and subsidiaries as of December 31, 2000 and 1999, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States.

Arthur Andersen LLP

Portland, Oregon

January 26, 2001

(except with respect to the matter discussed in Note 13, as to which the date is February 21, 2001)

Portland General Electric Company and Subsidiaries

Consolidated Statements of Income

For the Years Ended December 31	**2000**	**1999**	**1998**
		(Millions of Dollars)	
Operating Revenues	$ 2,253	$ 1,378	$ 1,176
Operating Expenses			
Purchased power and fuel	1,461	654	455
Production and distribution	126	119	120
Administrative and other	137	115	114
Depreciation and amortization	164	155	149
Taxes other than income taxes	65	61	57
Income taxes	94	84	81
	2,047	1,188	976
Net Operating Income	206	190	200

Other Income (Deductions)			
Miscellaneous	10	13	13
Income taxes	(3)	(6)	(1)
	7	7	12
Interest Charges			
Interest on long-term debt and other	63	59	68
Interest on short-term borrowings	9	10	7
	72	69	75
Net Income	141	128	137
Preferred Dividend Requirement	2	2	2
Income Available for Common Stock	$ 139	$ 126	$ 135

Portland General Electric Company and Subsidiaries

Consolidated Statements of Retained Earnings

For the Years Ended December 31	2000	1999	1998
	(Millions of Dollars)		
Balance at Beginning of Year	$ 401	$ 356	$ 270
Net Income	141	128	137
	542	484	407
Dividends Declared			
Common stock - cash	81	81	49
Preferred stock	2	2	2
	83	83	51
Balance at End of Year	$ 459	$ 401	$ 356

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

Portland General Electric Company and Subsidiaries

Consolidated Balance Sheets

At December 31	2000	1999
	(Millions of Dollars)	
Assets		
Electric Utility Plant - Original Cost		
Utility plant (includes construction work in progress of $78 and $44)	$ 3,423	$ 3,295
Accumulated depreciation	(1,532)	(1,430)
	1,891	1,865
Other Property and Investments		
Contract termination receivable	57	85
Receivable from parent	80	89
Nuclear decommissioning trust, at market value	33	42
Trust owned life insurance	86	85
Miscellaneous	21	17
	277	318
Current Assets		
Cash and cash equivalents	60	-
Accounts and notes receivable	287	140
Unbilled and accrued revenues	60	49
Assets from price risk management activities	279	-
Inventories, at average cost	31	37
Prepayments and other	61	41
	778	267
Deferred Charges		

Unamortized regulatory assets	484	691
Miscellaneous	22	26
	506	717
	$ 3,452	$ 3,167

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	480	480
Retained earnings	459	401
Cumulative preferred stock		
Subject to mandatory redemption	30	30
Long-term obligations	798	701
	1,927	1,772
Current Liabilities		
Long-term debt due within one year	52	32
Short-term borrowings	16	266
Accounts payable and other accruals	286	163
Liabilities from price risk management activities	266	-
Customer deposits	139	4
Accrued interest	14	11
Dividends payable	1	1
Accrued taxes	8	12
	782	489
Other		
Deferred income taxes	365	351
Deferred investment tax credits	27	36
Trojan decommissioning and transition costs	218	234
Unamortized regulatory liabilities	34	197
Miscellaneous	99	88
	743	906
	$ 3,452	$ 3,167

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

Portland General Electric Company and Subsidiaries

Consolidated Statements of Cash Flow

For the Years Ended December 31	2000	1999	1998
		(Millions of Dollars)	
Cash Flows From Operating Activities:			
Reconciliation of net income to net cash provided by operating activities			
Net income	$ 141	$ 128	$ 137
Non-cash items included in net income:			
Depreciation and amortization	164	155	149
Deferred income taxes	(8)	(3)	(6)
Net assets from price risk management activities	(13)	-	-
Other non-cash income and expenses (net)	17	(10)	(11)
Changes in working capital:			
(Increase) decrease in receivables	(158)	(9)	(8)
Increase (decrease) in payables	257	(1)	(50)
Other working capital items - net	(14)	(18)	(1)
Other - net	38	(4)	55
Net Cash Provided by Operating Activities	424	238	265

Cash Flows From Investing Activities:			
Capital expenditures	(173)	(182)	(144)
Proceeds from sales of assets	27	-	-
Other - net	(2)	6	(4)
Net Cash Used in Investing Activities	(148)	(176)	(148)
Cash Flows From Financing Activities:			
Repayment of long-term debt	(33)	(113)	(214)
Net increase (decrease) in short-term borrowings	(250)	161	6
Issuance of long-term debt	150	-	142
Dividends paid	(83)	(83)	(51)
Repayment of loans on corporate owned life insurance	-	(32)	-
Other - net	-	1	1
Net Cash Used in Financing Activities	(216)	(66)	(116)
Increase (Decrease) in Cash and Cash Equivalents	60	(4)	1
Cash and Cash Equivalents, Beginning of Period	-	4	3
Cash and Cash Equivalents, End of Period	$ 60	$ -	$ 4
Supplemental disclosures of cash flow information			
Cash paid during the year:			
Interest, net of amounts capitalized	$ 66	$ 60	$ 63
Income taxes	109	139	133

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 1, 1997, Portland General Corporation (PGC), the former parent of PGE, merged with Enron Corp. (Enron) with Enron continuing in existence as the surviving corporation. PGE is currently a wholly owned subsidiary of Enron and subject to control by the Board of Directors of Enron. PGE is engaged in the generation, purchase, transmission, distribution, and sale of electricity in the State of Oregon. PGE also sells energy to wholesale customers, predominately utilities, marketers and brokers throughout the western United States. PGE's Oregon service area is 3,150 square miles, including 51 incorporated cities, of which Portland and Salem are the largest, within a state-approved service area allocation of 4,070 square miles. At the end of 2000, PGE's service area population was approximately 1.5 million, comprising about 44% of the state's population and serving approximately 725,000 customers.

On November 8, 1999, Enron announced that it had entered into a purchase and sale agreement to sell PGE to Sierra Pacific Resources (Sierra) for $2.1 billion. The closing has been delayed by the effect of recent events in California and Nevada on the buyer.

Note 1 - Summary of Significant Accounting Policies

Consolidation Principles

The consolidated financial statements include the accounts of PGE and its majority-owned subsidiaries. Inter-company 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.

Reclassifications

Certain amounts in prior years have been reclassified for comparative purposes.

Revenues

PGE accrues estimated unbilled revenues for services provided from the meter read date to month-end.

Purchased Power

PGE credits purchased power costs for the benefits received through a power purchase and sale contract with the Bonneville Power Administration (BPA). Reductions in purchased power costs that result from this exchange are passed directly to PGE's residential and small farm customers in the form of lower prices. A September 1998 agreement between PGE and BPA will continue to provide benefits to PGE's residential and small farm customers through at least June 30, 2001. A new agreement signed October 31, 2000, provides for continued benefits from July 1 through September 30, 2001 and provides for additional benefits over a ten-year period beginning October 1, 2001.

Depreciation

PGE's depreciation is computed on the straight-line method based on the estimated average service lives of the various classes of plant in service. Depreciation expense as a percent of the related average depreciable plant in service was approximately 4.2% in 2000 and 1999 and 4.3% in 1998.

The cost of renewal and replacement of property units is charged to plant, while repairs and maintenance costs are charged to expense as incurred. The cost of utility property units retired, other than land, is charged to accumulated depreciation.

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. AFDC is capitalized as part of the cost of plant and is credited to income but does not represent current cash earnings. The average rate used in 2000 was 6.8%.

Income Taxes

PGE's federal income taxes are a part of its parent company's consolidated federal income tax return. PGE pays for its tax liabilities when it generates taxable income and is reimbursed for its tax benefits by the parent company on a stand-alone basis. Deferred income taxes are provided for temporary differences between financial and income tax reporting. Amounts recorded for Investment Tax Credits (ITC) have been deferred and are being amortized to income over the approximate lives of the related properties, not to exceed 25 years. See Note 3, Income Taxes, for more details.

Price Risk Management

PGE engages in price risk management activities for both trading and non-trading purposes. Financial instruments utilized in connection with trading activities are accounted for using the mark-to-market method, pursuant to Emerging Issues Task Force (EITF) Issue 98-10, "Accounting for Energy Trading and Risk Management Activities". Under this method of accounting, instruments utilized for trading activities are reflected at fair value, with unrealized gains and losses recorded within "Purchase power and fuel" on the Income Statement and shown as "Assets and Liabilities from Price Risk Management Activities" in the Balance Sheet. Gains and losses on instruments utilized in non-trading activities are recognized in purchased power and fuel expense, or in wholesale revenue upon settlement. See Note 8, Price Risk Management, for further information.

Cash and Cash Equivalents

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

Trust Owned Life Insurance

Under the purchase and sale agreement between Enron and Sierra, PGE's investment in trust owned life insurance will be transferred to Enron before the sale of PGE to Sierra.

Energy Efficiency

Beginning October 1, 2000, PGE's Demand Side Management (DSM) program expenditures, formerly deferred and amortized over a five-year period, are being expensed. This change in cost recognition, approved by the OPUC, was accompanied by an approximate 1% increase in rates. PGE's unamortized DSM investment prior to implementation of the change continues to be recovered in rates over a five-year period. This change in cost recognition is in response to SB1149, which encourages a competitive marketplace for energy services and provides for a public service charge to fund conservation measures.

Major Maintenance and Overhaul Accruals

PGE performs periodic major maintenance inspections and overhauls at its Coyote Springs combustion turbine generating plant based upon manufacturers' specifications and hours of operation. The OPUC has authorized the Company to accrue and recover in rates the projected costs of such major maintenance and overhaul activities. The estimated cost of such activities is accrued each month to Production and distribution expense, with an equal amount recorded as a non-current miscellaneous liability on the balance sheet, with the actual cost of work performed charged to the liability account.

Regulatory Assets and Liabilities

The Company is subject to the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation". When the requirements of SFAS No. 71 are met, PGE 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 ultimately will be refunded to customers. Regulatory assets and liabilities reflected as deferred charges and other liabilities in the financial statements are amortized over the period in which they are included in billings to customers.

Amounts in the Consolidated Balance Sheets as of December 31 relate to the following:

	2000	1999
	(Millions of Dollars)	
Unamortized regulatory assets:		
Trojan investment	$ -	$202
Trojan decommissioning costs	190	196
Income taxes recoverable	136	165
Prior tax benefits recoverable	45	-
Debt reacquisition costs	21	23
Conservation investments - secured	54	61
Energy efficiency programs	19	22
Miscellaneous	19	22
Total	$484	$691
Unamortized regulatory liabilities:		
Deferred gain on SCE termination	$ -	$ 81
Merger payment obligation	-	88
NEIL distribution	19	-
Deferred gain on sale of major asset	11	-
Miscellaneous	4	28
Total	$ 34	$197

During 2000, the Company 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 of approximately $180 million, along with several largely offsetting regulatory liabilities. The largest of such amounts were the deferred gain on the termination of a power sales agreement with Southern California Edison Company (SCE) and the Enron/PGC merger payment obligation. The settlement also allows recovery of approximately $47 million in income tax benefits 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 Matters, for further information.

As of December 31, 2000, a majority of the Company's regulatory assets and liabilities are being reflected in rates charged to customers. Based on rates in place at year-end 2000, the Company estimates that it will collect substantially all of its regulatory assets within the next 11 years.

Conservation investments - secured - In 1996, $81 million of PGE's energy efficiency investment was designated as Bondable Conservation Investment upon PGE's issuance of 10-year 6.91% Conservation Bonds collateralized by OPUC-assured future revenues. These bonds provide savings to customers while granting PGE immediate recovery of its prior energy efficiency program expenditures. Revenues collected from customers fund the debt service obligation on the conservation bonds. At December 31, 2000, the outstanding balance on the bonds was $53 million.

Note 2 - Employee Benefits

Pension and Other Post-Retirement Plans

PGE participates in a non-contributory defined benefit pension plan (the Plan) with other affiliated companies. Substantially all of the plan members are current or former PGE employees. The plan's assets are held in a trust.

PGE also participates in non-contributory post-retirement health and life insurance plans ("Other Benefits" below). 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 employee's beneficiary association to fund these plans.

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

	Pension Benefits		Other Benefits	
	2000	1999	2000	1999
Reconciliation of benefit obligation:				
Obligation at January 1	$ 267	$ 284	$ 29	$ 29
Service cost	9	8	1	1
Interest cost	20	20	2	2
Plan amendments	-	6	-	-
Curtailments (a)	-	(8)	-	-
Participants' contributions	-	-	1	-
Actuarial loss (gain)	2	(25)	1	(1)
Benefit payments	(18)	(18)	(3)	(2)
Obligation at December 31	$ 280	$ 267	$ 31	$ 29
Reconciliation of fair value of plan assets:				
Fair value of plan assets at January 1	$ 439	$ 401	$ 35	$ 33
Actual return on plan assets	2	55	(3)	3
Participants' contributions	-	-	-	1
Company contributions	1	1	1	-
Benefit payments	(18)	(18)	(3)	(2)
Fair value of plan assets at December 31	$ 424	$ 439	$ 30	$ 35
Funded status:				
Funded status at December 31	$ 144	$ 172	$ (1)	$ 6
Unrecognized transition (asset)	(8)	(9)	4	4
Unrecognized prior service cost	12	13	2	2
Unrecognized gain	(121)	(162)	(5)	(13)
Prepaid Pension Cost	$ 27	$ 14	$ 0	$ (1)
Assumptions:				
Discount rate used to calculate benefit obligation	7.75%	7.75%	7.75%	7.75%
Rate of increase in future compensation levels	4.0 - 9.5%	4.0 - 9.5%	4.0 - 9.5%	4.0 - 9.5%
Long-term rate of return on assets	9.00%	9.00%	9.50%	9.50%
Components of net periodic pension expense:				
Service cost	$ 9	$ 8	$ 1	$ 1
Interest cost on benefit obligation	20	20	2	2
Expected return on plan assets	(35)	(31)	(3)	(2)
Amortization of transition asset	(2)	(2)	-	-
Amortization of prior service cost	2	1	-	-
Recognized gain	(6)	(3)	-	(1)

Effect of curtailment (a)	-	(5)	-	-
Net periodic pension expense (benefit)	$ (12)	$ (12)	$ 0	$ 0

(a) Represents one-time nonrecurring event associated with certain union employees ceasing participation in the pension plan as a result of union negotiations.

Included in the above Pension Benefits amounts are the unfunded obligations for the supplemental executive retirement plan. At December 31, 2000 and 1999, respectively, the projected benefit obligation for this plan was $13 million and $12 million. Under the purchase and sale agreement between Enron and Sierra, this obligation will be assumed by Enron before the sale of PGE to Sierra.

For measurement purposes, a 10.0% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2001. The rate was assumed to decrease .5% per year to 5.0% in 2010 and remain at that level thereafter. Assumed health care cost trend rates have a significant effect on the 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):

	1-Percentage Point Increase	1-Percentage Point Decrease
Effect on total of service and interest cost components	$0.1	$(0.1)
Effect on post-retirement benefit obligation	$0.7	$(0.6)

Deferred Compensation

PGE provides certain employees with benefits under an unfunded Management Deferred Compensation Plan (MDCP). Obligations for the MDCP were $40 million and $34 million at December 31, 2000 and 1999, respectively. Under the purchase and sale agreement between Enron and Sierra, this obligation will be assumed by Enron before the sale of PGE to Sierra.

Employee Stock Ownership Plan

PGE participated in the PGH Retirement Savings Plan through June 30, 1999. On July 1, 1999, the plan merged into the Enron Savings Plan and PGE continued participation. The successor plan includes an Employee Stock Ownership Plan (ESOP). Previously matched 50% by employer contributions, employee contributions up to 6% of base pay will be matched 100% by employer contributions in the form of Enron common stock, beginning in 2001.

All Employee Stock Option Plan

Enron stock options were granted to PGE employees on December 31, 1997. The options were granted at the fair value of the stock at the date of the grant. One-third of the options vested each year in 1998, 1999, and 2000. PGE pays Enron the estimated value of the shares vesting each year. The fair value of shares vesting in both 2000 and 1999 was $4 million. The value is calculated using the Black-Scholes option-pricing model.

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 (millions of dollars):

	2000	1999	1998
Income Tax Expense			
Currently payable			
Federal	$ 88	$ 78	$75
State and local	17	15	13
	105	93	88
Deferred income taxes			
Federal	(2)	(1)	(1)

State and local	-	2	(1)
	(2)	1	(2)
Investment tax credit adjustments	(6)	(4)	(4)
	$ 97	$ 90	$ 82
Provision Allocated to:			
Operations	$ 94	$ 84	$ 81
Other income and deductions	3	6	1
	$ 97	$ 90	$ 82
Effective Tax Rate Computation:			
Computed tax based on statutory federal income tax rates applied to income before income taxes	$ 84	$ 77	$ 77
Flow through depreciation	6	7	4
State and local taxes - net	11	11	7
Investment tax credits	(6)	(4)	(4)
Excess deferred taxes	(1)	(1)	(1)
Other	3	-	(1)
	$ 97	$ 90	$ 82
Effective tax rate	40.8%	41.3%	37.4%

As of December 31, 2000 and 1999, the significant components of PGE's deferred income tax assets and liabilities were as follows (millions of dollars):

	2000	**1999**
Deferred Tax Assets		
Depreciation and amortization	$ 24	$ 24
Employee benefits	13	15
Regulatory liabilities		
SCE termination	-	39
Merger payment obligation	-	35
NEIL distribution	8	-
Deferred gain on sale of major asset	4	-
Miscellaneous	5	10
Other deferred tax assets	13	20
	67	143
Deferred Tax Liabilities		
Depreciation and amortization	$330	$356
Trojan investment	-	56
Receivable from parent	31	35
Price risk management	5	-
Regulatory assets		
Prior tax benefits recoverable	18	-
Debt reacquisition costs	8	9
Conservation investments	18	19
Energy efficiency programs	8	8
Miscellaneous	-	9
Other deferred tax liabilities	14	2
	432	494
Total	$365	$351

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

(Millions of Dollars except share amounts)	Common Stock Number of Shares	Common Stock $3.75 Par Value	Cumulative Preferred Number of Shares	Cumulative Preferred No- Par Value	Paid-in Capital
December 31, 1998	42,758,877	$160	300,000	$30	$480
December 31, 1999	42,758,877	$160	300,000	$30	$480
December 31, 2000	42,758,877	$160	300,000	$30	$480

Cumulative Preferred Stock

PGE has authorized 30 million shares of cumulative preferred stock, no par value; there are 300,000 shares of the 7.75% series outstanding. The 7.75% series preferred stock has an annual sinking fund requirement, which requires the redemption of 15,000 shares at $100 per share beginning in 2002. At its option, PGE may redeem, through the sinking fund, an additional 15,000 shares each year. All remaining shares shall be mandatorily redeemed by the operation of the sinking fund in 2007. This series is only redeemable by operation of the sinking fund.

No dividends may be paid on common stock or any class of stock over which the preferred stock has priority unless all amounts required to be paid for dividends and sinking fund payments have been paid or set aside, respectively.

Common Stock Dividend

Enron is the sole shareholder of PGE common stock. PGE is restricted from paying dividends or making other distributions to Enron without prior OPUC approval to the extent such payment or distribution would reduce PGE's common stock equity capital below 48% of its total capitalization.

The purchase and sale agreement between Enron and Sierra requires PGE to pay dividends to Enron equal to the lesser of PGE's aggregate income available for common stock for the period January 1, 1999 through the closing date or, an amount equal to the aggregate of approximately $129 million for 1999, $143 million for 2000, and $144 million for 2001 (prorated to the date of sale). Based on net income and dividend payments made for these time periods, as of December 31, 2000, an additional cash dividend of $104 million would be due Enron under terms of the purchase and sale agreement.

Note 5 - Credit Facilities and Debt

At December 31, 2000, PGE had committed lines of credit totaling $250 million. Credit lines of $150 million, with an annual fee of 0.11%, expire in July 2003; credit lines of $100 million, with an annual fee of 0.085%, expire in July 2001. These lines of credit, which do not require compensating cash balances, are used primarily as backup for both commercial paper and borrowings from commercial banks under uncommitted lines of credit.

Unused committed lines of credit must be at least equal to the amount of PGE's commercial paper outstanding. Commercial paper and lines of credit borrowings are at rates reflecting current market conditions.

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

	2000	1999
As of year-end:	(Millions of Dollars)	
Aggregate short-term debt outstanding		
Commercial paper	$ 16	$ 266
Weighted average interest rate*		
Commercial paper	6.8%	6.1%

Committed lines of credit	$ 250	$ 300
For the year ended:		
Average daily amounts of short-term debt outstanding		
Commercial paper	$ 120	$ 162
Weighted daily average interest rate*		
Commercial paper	6.2%	5.5%
Maximum amount outstanding during the year	$ 278	$ 266

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

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

Schedule of long-term debt at December 31	2000	1999
	(Millions of Dollars)	
First Mortgage Bonds		
Maturing 2000 - 2005 6.47% - 9.07%	$ 163	$ 170
Maturing 2007 7.15%	50	68
Maturing 2021 - 2023 7.75% - 9.46%	160	160
	373	398
Pollution Control Bonds		
Port of Morrow, Oregon, variable rate, due 2031		
(Average rate 4.3% for 2000, 3.4% for 1999)	6	6
Port of Morrow, Oregon, variable rate, due 2033		
(4.60% fixed rate to 2003)	23	23
City of Forsyth, Montana, variable rate, due 2033		
(4.60% - 4.75% fixed rate to 2003)	119	119
Port of St. Helens, Oregon, variable rate due 2010 & 2014		
(4.80% - 5.25% fixed rate to 2003)	47	47
Port of St. Helens, Oregon, due 2014 (7.13% fixed rate)	5	5
	200	200
Other		
8.25% Junior Subordinated Deferrable Interest Debentures,		
due December 31, 2035	75	75
6.91% Conservation Bonds maturing monthly to 2006	53	61
7.875% Notes due March 15, 2010	150	-
Unamortized debt discounts	(1)	(1)
	277	135
	850	733
Long-term debt due within one year	(52)	(32)
Total long-term debt	$ 798	$ 701

The following principal amounts of long-term debt (excluding commercial paper) become due through regular maturities (millions of dollars):

2001	2002	2003	2004	2005

Maturities:					
PGE	$52	$23	$49	$55	$28

Note 6 - Other Financial Instruments

Financial Instruments

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

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

Other investments - Other investments approximate market value.

Redeemable preferred stock - The fair value of redeemable preferred stock is based on quoted market prices.

Long-term debt - The fair value of long-term debt is estimated based on the quoted market prices for the same or similar issues or on the current rates offered to PGE for debt of similar remaining maturities.

The estimated fair values of debt and equity instruments are as follows (millions of dollars):

	2000		1999	
	Carrying Amount	**Fair Value**	**Carrying Amount**	**Fair Value**
Preferred stock subject to mandatory redemption	$ 30	$ 30	$ 30	$ 32
Long-term debt including current maturities	$850	$869	$733	$714

Note 7 - Commitments

Natural Gas Agreements

PGE has entered into agreements for the purchase, sale, and transmission of natural gas from domestic and Canadian sources for its natural gas-fired generating facilities, requiring net payments of approximately $162 million in 2001, $72 million in 2002, $15 million in 2003 through 2005, and $93 million over the remaining years of the contracts. These contracts expire at varying dates from 2001 to 2015.

Purchase Commitments

Certain commitments have been made related to capital expenditures planned for 2001. As of December 31, 2000, total commitments of approximately $80 million have been made for system construction, hydro re-licensing, and information systems.

Coal Agreements

PGE has coal agreements with take-or-pay obligations totaling approximately $8 million for 2001.

Purchased Power

PGE has long-term power purchase contracts with certain public utility districts in the state of Washington and with the City of Portland, Oregon. PGE is required to pay its proportionate share of the operating and debt service costs of the hydro projects whether or not they are operable.

Selected information is summarized as follows (millions of dollars):

	Rocky Reach	Priest Rapids	Wanapum	Wells	Portland Hydro

Revenue bonds outstanding at December 31, 2000	$214	$165	$180	$178	$ 31
PGE's current share of:					
Output	12.0%	13.9%	18.7%	20.3%	100%
Net capability (megawatts)	154	133	194	171	36
Annual cost, including debt service:					
2000	$ 7	$ 4	$ 6	$ 6	$ 4
1999	6	4	6	6	4
1998	6	4	6	6	4
Contract expiration date	2011	2005	2009	2018	2017

PGE's share of debt service costs, excluding interest, will be approximately $7 million for 2001, $8 million for 2002, $9 million for 2003, and $7 million for 2004 and 2005. The minimum payments through the remainder of the contracts are estimated to total $59 million.

PGE has entered into power purchase and sale contracts with other utilities, requiring net payments of approximately $603 million in 2001, $187 million in 2002, $36 million in 2003, and $19 million in 2004 and 2005. After that date, contract charges will average $20 million annually until 2016.

Leases

PGE has operating lease arrangements for its headquarters complex, coal-handling facilities and certain railroad cars for Boardman. PGE's aggregate rental payments charged to expense amount to $20 million for 2000, $24 million for 1999, and $23 million for 1998.

Future minimum lease payments under non-cancelable leases are as follows (millions of dollars):

Year Ending December 31	Operating Leases (Net of Sublease Rentals)
2001	$ 20
2002	9
2003	9
2004	10
2005	8
Remainder	148
Total	$204

Included in the future minimum operating lease payments schedule above is approximately $104 million for PGE's headquarters complex.

Note 8 - Price Risk Management

PGE is exposed to market risk arising from the need to purchase power to meet the needs of its retail customers and to purchase fuel for its natural gas fired generating units. The Company uses instruments such as forward contracts, options, and swaps to mitigate risk that arises from market fluctuations of commodity prices. In 2000, PGE expanded the use of such instruments for trading purposes. Instruments utilized in connection with these trading activities are accounted for as prescribed by Issue 98-10 of the Emerging Issues Task Force of the Financial Accounting Standards Board ("EITF 98-10"). Under EITF 98-10, the Company's portfolio of electric forward contracts and natural gas swaps with third parties used in its trading activities are reflected at fair value, with gains and losses included in earnings and shown as "Assets and liabilities from price risk management activities" in the Consolidated Balance Sheet. Changes in assets and liabilities from energy trading activities result primarily from changes in the valuation of the portfolio of contracts, newly originated transactions, and the timing of settlement. Market prices used to value these transactions reflect management's best estimate considering various factors, including closing exchange and over-the-counter quotations, time value, and volatility factors underlying the commitments.

Unrealized gains and losses from newly originated contracts and the impact of price movements are recorded within "Purchased power and fuel" on the Income Statement. In 2000, an unrealized net gain of $16 million on electricity forward contracts was recorded, partially offset by an unrealized $3 million net loss on natural gas swaps.

The fair value as of December 31, 2000, and the average fair value of instruments related to price risk management trading activities held during the year are set forth below:

	Fair Value as of 12/31/2000		Average Fair Value for the Year Ended 12/31/2000[(a)]	
(Dollars in Millions)	Assets	Liabilities	Assets	Liabilities
Electric forward contracts	$ 270	$ 254	$ 78	67
Natural gas swaps	9	12	4	5
Total	$ 279	$ 266	$ 82	$ 72

(a) Computed using the balances at each month-end.

Note 9 - Jointly Owned Plant

At December 31, 2000, PGE had the following investments in jointly owned generating plants (millions of dollars):

Facility	Location	Fuel	MW Capacity	PGE % Interest	Plant In Service	Accumulated Depreciation
Boardman	Boardman, OR	Coal	561	65.0	$ 391	$232
Colstrip 3&4	Colstrip, MT	Coal	1,556	20.0	456	263

The dollar amounts in the table above represent PGE's share of each jointly owned plant. Each participant in the above generating plants has provided its own financing. The Company's share of the direct expenses of these plants is included in the corresponding operating expenses in the consolidated statements of income.

In April 2000, the Confederated Tribes of Warm Springs (Tribes) and PGE executed an agreement that would result in shared ownership and control of PGE's 408-MW Pelton Round Butte hydroelectric project, which provides about 20% of the Company's power-generating capacity. The agreement with the Tribes, which was approved by the OPUC in August 2000, provides for increased ownership by the Tribes over a proposed 50-year license period, which PGE and the Tribes are now jointly pursuing with the FERC. The Tribes will initially purchase a one-third interest at the net depreciated book value on December 31, 2001. PGE will continue to operate the project.

Note 10 - Legal Matters

Trojan Investment Recovery - In 1993, PGE sought full recovery of and a rate of return on its Trojan plant costs, including decommissioning, in a general rate case filing with the OPUC. The filing was a result of PGE's decision earlier in the year to cease commercial operation of Trojan as a part of its least cost planning process. In 1995, the OPUC issued a general rate order which granted the Company recovery of, and a rate of return on, 87% of its remaining investment in Trojan plant costs, and full recovery of its estimated decommissioning costs through 2011.

Numerous challenges, appeals and requested reviews have been filed in Marion County, Oregon Circuit Court, Oregon Court of Appeals and with the Oregon Supreme Court on the issue of the OPUC's authority under Oregon law to grant recovery of and a return on the Trojan investment. The primary plaintiffs in the litigation are the Citizens' Utility Board (CUB) and the Utility Reform Project (URP). Rulings issued to date by the Circuit Court and the Court of Appeals have been inconsistent on the issue. The Court of Appeals issued the latest ruling in 1998 stating that the OPUC does not have the authority to allow PGE to recover a return on the Trojan investment, but upheld the OPUC's authorization of PGE's recovery of the Trojan investment. PGE and the OPUC requested the Oregon Supreme Court to conduct a review of the Court of Appeals' decision on the return on investment issue. In addition, URP requested the Oregon Supreme Court to review the Court of Appeals decision on the return of investment issue. The Supreme Court has indicated it will conduct a review.

In 2000, PGE entered into settlement agreements with CUB and the staff of the OPUC of the litigation related to PGE's recovery of its investment in the Trojan plant. Under the agreements, CUB agreed to withdraw from the litigation and support the settlement as the means to resolve the Trojan litigation. The settlement, which was approved by the OPUC, allowed PGE to remove from its balance sheet the remaining before-tax investment in Trojan of approximately $180 million at September 30, 2000, along with several largely offsetting regulatory liabilities. The largest of such amounts consist of before-tax credits of approximately $79 million in customer benefits related to the previous settlement of power contracts with two other utilities and about $80 million remaining obligation under terms of the Enron/PGC merger. The settlement also allows PGE recovery of approximately $47 million in income tax benefits related to the Trojan investment which had been flowed 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. After offsetting the investment in Trojan with these credits and prior tax benefits, the remaining Trojan regulatory asset balance of approximately $5 million (after tax) was expensed. As a result of the settlement, PGE's investment in Trojan is no longer included in rates charged to customers, either through a return of or a return on that investment. The URP has challenged the settlement agreements and the OPUC order. Collection of decommissioning costs at Trojan is unaffected by the settlement agreements or the OPUC order.

With CUB's withdrawal, the URP is the one remaining significant adverse party in the litigation. The URP has indicated it plans to continue to challenge the orders that allow PGE recovery of and a return on its investment in Trojan. The Oregon Supreme Court's review is on hold pending resolution of the URP's latest challenge with the OPUC.

Management cannot predict the ultimate outcome of the above litigation. However, it 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 a future reporting period.

Other Legal Matters - PGE is party to various other claims, legal actions and complaints arising in the ordinary course of business. These claims are not material.

Note 11 - Trojan Nuclear Plant

Plant Shutdown and Transition Costs - PGE is a 67.5% owner of Trojan. In early 1993, PGE ceased commercial operation of the nuclear plant. Since plant closure, PGE has committed itself to a safe and economical transition toward a decommissioned plant. Transition costs associated with operating and maintaining the spent fuel pool and securing the plant until fuel is transferred to dry storage will be paid from current operating funds. Delays have extended the expected completion date of transferring the fuel to dry storage through 2003.

Decommissioning - In October 2000, PGE filed an updated decommissioning plan estimate with the OPUC. The plan estimates PGE's cost to decommission Trojan at $337 million reflected in nominal dollars (actual dollars expected to be spent in each year). The primary reason for the reduction from the $351 million 1994 estimate is a lower inflation rate, coupled with the acceleration of certain decommissioning activities and partially offset by cost increases related to the spent fuel storage project. The current estimate assumes that the majority of decommissioning activities will occur between 1998 and 2004, while fuel management costs extend through the year 2018. The original plan represents a site-specific decommissioning estimate performed for Trojan by an engineering firm experienced in estimating the cost of decommissioning nuclear plants. Updates to the plan's original estimate have been prepared by PGE. Final site restoration activities are anticipated to begin in 2018 after PGE completes shipment of spent fuel to a USDOE facility (see the Nuclear Fuel Disposal discussion below). Stated in 2000 dollars, the decommissioning cost estimate is $300 million.

TROJAN DECOMMISSIONING LIABILITY

(Millions of Dollars)

Estimate - 12/31/94	$351
Updates filed with NRC - 11/16/95	7
Updates filed with OPUC - 12/01/97	(19)
Updates filed with OPUC - 10/02/00	(2)
	337
Expenditures through 12/31/00	(140)
Liability - 12/31/00	197
Transition costs	21
Total Trojan obligation	$218

DECOMMISSIONING TRUST ACTIVITY

(Millions of Dollars)

	2000	1999
Beginning Balance	$42	$72
Activity		
Contributions	15	14
Gain	2	-
Disbursements	(26)	(44)
Ending Balance	$33	$42

PGE is collecting $14 million annually through 2011 from customers for decommissioning costs. These amounts are deposited in an external trust fund, which is limited to reimbursing PGE for activities covered in Trojan's decommissioning plan. Funds were withdrawn during 2000 to cover the costs of general decommissioning and activities in support of the independent spent fuel storage installation. Decommissioning funds are invested in investment-grade preferred stock, tax-exempt bonds, and U.S. Treasury bonds. Year-end balances are valued at market.

Earnings on the trust fund are used to reduce the amount of decommissioning costs to be collected from customers. PGE expects any future changes in estimated decommissioning costs to be incorporated in future revenues to be collected from customers.

Nuclear Fuel Disposal and Cleanup of Federal Plants - PGE contracted with the USDOE for permanent disposal of its spent nuclear fuel in federal facilities at a cost of 0.1 cent per net kilowatt-hour sold at Trojan which the Company paid during the period the plant operated. Significant delays are expected in the USDOE acceptance schedule of spent fuel from domestic utilities. The federal repository, which was originally scheduled to begin operations in 1998, is now estimated to commence operations no earlier than 2010. This may create difficulties for PGE in disposing of its high-level radioactive waste by 2018. However, federal legislation has been introduced which, if passed, would require USDOE to provide interim storage for high-level waste until a permanent site is established. PGE intends to build an interim storage facility at Trojan to house the nuclear fuel until a federal site is available.

The Energy Policy Act of 1992 provided for the creation of a Decontamination and Decommissioning Fund to finance the cleanup of USDOE gas diffusion plants. Funding comes from domestic nuclear utilities and the federal government. Each utility contributes based on the ratio of the amount of enrichment services the utility purchased to the total amount of enrichment services purchased by all domestic utilities prior to the enactment of the legislation. Based on Trojan's 1.1% usage of total industry enrichment services, PGE's portion of the funding requirement is approximately $17 million. Amounts are funded over 15 years beginning with the USDOE's fiscal year 1993. Since enactment, PGE has made the first nine of the 15 annual payments with the first payment made in September 1993.

Nuclear Insurance - The Price-Anderson Amendment of 1988 limits public liability claims that could arise from a nuclear incident and provides for loss sharing among all owners of nuclear reactor licenses. Because Trojan has been permanently defueled, the NRC has exempted PGE from participation in the secondary financial protection pool covering losses in excess of $200 million at other nuclear plants. In addition, the NRC has reduced the required primary nuclear insurance coverage for Trojan from $200 million to $100 million following a 3 year cool-down period of the nuclear fuel that is still on-site. The NRC has allowed PGE to self-insure for on-site decontamination. PGE continues to carry non-contamination property insurance on the Trojan plant at the $158 million level.

Note 12 - Related Party Transactions

As part of its ongoing operations, PGE receives management services from Enron and provides incidental services to Enron and its affiliated companies. In 2000, approximately $35 million was paid to Enron for allocated overhead and other direct costs, including $5 million for retirement savings plan matching, $7 million for medical and dental benefits, and $4 million for the Employee Stock Option Plan. In 1999, PGE paid $23 million to Enron for allocated overhead and other direct costs, including PGE's $4 million share of the Employee Stock Option Plan. In 1998, PGE paid $17 million to Enron for management services, including $5 million for employee stock options. In 2000, PGE electricity purchases from and sales to an Enron affiliate totaled $205 million and $206 million, respectively; in 1999, such purchases and sales both totaled $33 million, with no purchases or sales in 1998.

Note 13 - Receivables - California Wholesale Market

As of December 31, 2000, PGE had approximately $119 million of accounts receivable that may be affected by the financial condition of two major California utilities. A balance of approximately $60 million was owed by Southern California Edison Company (SCE) under terms of a 1996 agreement providing for the termination of a Power Sales Agreement between the two companies. In addition, a balance of approximately $59 million was owed the Company by the California Independent System Operator (ISO) and the California Power Exchange (PX) for wholesale electricity sales. The Company estimates that approximately 70%-80% of such sales were to SCE and Pacific Gas & Electric Company (PG&E), major participants with other California utilities in the ISO and PX for the purchase of wholesale electricity.

Significant increases in wholesale power prices in 2000 and in early 2001, due in part to a sharp increase in natural gas prices paid by generators in producing electricity, has severely affected the financial stability of both SCE and PG&E. Recently, the utilities' wholesale power purchase costs have greatly exceeded revenues collected from customers through rates that are currently frozen, requiring the utilities to finance the majority of their power purchase costs.

Adverse reaction of the credit markets to continued regulatory uncertainty over SCE's and PG&E's ability to recover their power procurement costs has materially and adversely affected their liquidity. Both companies have recently defaulted on financial obligations and their ability to make future payments to PGE is in question. Unless legislative or regulatory actions are taken, the utilities may be unable to secure additional sources of financing and may have to seek protection of the bankruptcy courts.

SCE has made its scheduled 2001 payments to date under the termination agreement. PGE continued to make limited sales to the ISO and PX in early 2001 primarily under federal order. The ISO made its scheduled January 2001 payment; however, PGE received approximately 24% of the $8.2 million payment due in early February. The PX has paid approximately 77% of the $1.6 million due in January and has delayed payment of the $7.6 million amount due in February. The total balance due from both the ISO and PX is approximately $75 million as of February 21, 2001. PGE is pursuing collection of all past due amounts.

Although the Company has established general credit reserves for amounts due under its wholesale electricity contracts, no reserves have been specifically provided for amounts due from SCE under the termination agreement or from the ISO and PX for wholesale power sales to SCE and PG&E. Although some wholesale power sales may be mandated by the federal government, PGE management continues to evaluate and monitor the prudency of future sales to the California market.

The Company has numerous options available to pursue collection of any amounts ultimately not received, including legal, regulatory or other means. Due to the uncertainties surrounding the financial stability of SCE and PG&E and the California power situation, management cannot predict the ultimate realization of these receivables, nor can it reasonably estimate any possible loss.

Management believes that the ultimate outcome of these matters will not have a material adverse impact on the financial condition of the Company. However, it may have a material impact on the results of operations for future reporting periods.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

PORTLAND GENERAL ELECTRIC COMPANY

(Registrant)

February 22, 2001	By:	/s/ James J. Piro James J. Piro Vice President Chief Financial Officer and Treasurer
February 22, 2001	By:	/s/ Kirk M. Stevens Kirk M. Stevens Controller and Assistant Treasurer