UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

[X] **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 2001

OR

[ ] **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Transition period from ________________ to ________________

Commission File Number 1-5532-99

PORTLAND GENERAL ELECTRIC COMPANY

(Exact name of registrant as specified in its charter)

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

121 SW Salmon Street, Portland, Oregon 97204

(Address of principal executive offices) (zip code)

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of July 31, 2001: 42,758,877 shares of Common Stock, $3.75 par value. (All shares are owned by Enron Corp.

)

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Definitions

BPA	Bonneville Power Administration
CUB	Citizens' Utility Board
Enron	Enron Corp.
FERC	Federal Energy Regulatory Commission
KWh	Kilowatt-Hour
Mill	One tenth of one cent
MWh	Megawatt-hour
OPUC or the Commission	Public Utility Commission of Oregon
PGE or the Company	Portland General Electric Company
Trojan	Trojan Nuclear Plant
URP	Utility Reform Project

PART I

Portland General Electric Company and Subsidiaries

Consolidated Income Statement

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2001	**2000**	**2001**	**2000**
	(Millions of Dollars)			
Operating Revenues	$ 831	$ 430	$ 1,597	$ 827
Operating Expenses				
Purchased power and fuel	632	251	1,214	453
Production and distribution	36	33	60	59
Administrative and other	37	34	65	69
Depreciation and amortization	45	38	86	77
Taxes other than income taxes	17	15	34	33
Income taxes	21	18	45	44
	788	389	1,504	735
Net Operating Income	43	41	93	92
Other Income				
Miscellaneous	4	3	2	7
Income taxes	-	-	2	1
	4	3	4	8
Interest Charges				
Interest on long-term debt and other	18	16	36	31

Interest on short-term borrowings	-	3	-	5
	18	19	36	36
Income before cumulative effect of a change in accounting principle	29	25	61	64
Cumulative effect of a change in accounting principle, net of related taxes of $(6)	-	-	11	-
Net Income	29	25	72	64
Preferred Dividend Requirement	-	-	1	1
Income Available for Common Stock	$ 29	$ 25	$ 71	$ 63

Consolidated Statement of Retained Earnings

(Unaudited)

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2001	2000	2001	2000
			(Millions of Dollars)	
Balance at Beginning of Period	$ 481	$ 419	$ 459	$ 401
Net Income	29	25	72	64
	510	444	531	465
Dividends Declared				
Common stock	20	20	40	40
Preferred stock	-	-	1	1
	20	20	41	41
Balance at End of Period	$ 490	$ 424	$ 490	$ 424

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

Portland General Electric Company and Subsidiaries

Consolidated Balance Sheet

(Unaudited)

	June 30, 2001	December 31, 2000
	(Millions of Dollars)	
Assets		
Electric Utility Plant - Original Cost		
Utility plant (includes construction work in progress of $121 and $78)	$ 3,527	$ 3,423
Accumulated depreciation	(1,600)	(1,532)
	1,927	1,891
Other Property and Investments		
Contract termination receivable	43	57
Receivable from parent	74	80
Nuclear decommissioning trust, at market value	35	33
Trust owned life insurance	83	86
Miscellaneous	29	21
	264	277
Current Assets		
Cash and cash equivalents	1	60
Accounts and notes receivable	332	287
Unbilled and accrued revenues	41	60
Assets from price risk management activities	397	279
Inventories, at average cost	40	31
Deposits	59	-
Prepayments and other	66	61
	936	778
Deferred Charges		

Unamortized regulatory assets	461	484
Miscellaneous	19	22
	480	506
	$ 3,607	$ 3,452

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	490	459
Accumulated other comprehensive income (loss)	(12)	-
Cumulative preferred stock		
Subject to mandatory redemption	29	30
Long-term debt	778	798
	1,925	1,927
Current Liabilities		
Long-term debt due within one year	68	52
Short-term borrowings	204	16
Accounts payable and other accruals	274	286
Liabilities from price risk management activities	352	266
Customer deposits	9	139
Deferred income taxes	18	5
Accrued interest	15	14
Dividends payable	1	1
Accrued taxes	21	8
	962	787
Other		
Deferred income taxes	347	360
Deferred investment tax credits	23	27
Trojan decommissioning and transition costs	214	218
Unamortized regulatory liabilities	35	34
Miscellaneous	101	99
	720	738
	$ 3,607	$ 3,452

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

Portland General Electric Company and Subsidiaries

Consolidated Statement of Cash Flows

(Unaudited)

	Six Months Ended June 30, 2001	Six Months Ended June 30, 2000
	(Millions of Dollars)	
Cash Flows From Operating Activities:		
Reconciliation of net income to net cash provided by (used in) operating activities		
Net income	$ 72	$ 64
Non-cash items included in net income:		
Cumulative effect of a change in accounting principle, net of tax	(11)	-
Depreciation and amortization	86	77
Deferred income taxes	1	(5)
Net assets from price risk management activities	(33)	(16)

Other non-cash income and expenses (net)	(5)	-
Changes in working capital:		
(Increase) Decrease in receivables	(26)	(21)
Increase (Decrease) in payables	(128)	23
Other working capital items - net	(73)	(5)
Other - net	4	9
Net Cash Provided by (Used in) Operating Activities	(113)	126
Cash Flows From Investing Activities:		
Capital expenditures	(103)	(73)
Other - net	14	1
Net Cash Used in Investing Activities	(89)	(72)
Cash Flows From Financing Activities:		
Net increase (decrease) in short-term borrowings	188	(128)
Repayment of long-term debt	(4)	(30)
Issuance of long-term debt	-	150
Dividends paid	(41)	(41)
Net Cash Provided by (Used in) Financing Activities	143	(49)
Increase (Decrease) in Cash and Cash Equivalents	(59)	5
Cash and Cash Equivalents, Beginning of Period	60	-
Cash and Cash Equivalents, End of Period	$ 1	$ 5
Supplemental disclosures of cash flow information		
Cash paid during the period:		
Interest, net of amounts capitalized	$ 31	$ 31
Income taxes	35	36

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

Portland General Electric Company and Subsidiaries

Notes to Consolidated Financial Statement

(Unaudited)

Note 1 - Principles of Interim Statements

The interim financial statements have been prepared by PGE and, in the opinion of management, reflect all material adjustments which are necessary for a fair statement of results for the interim period presented. Certain information and footnote disclosures made in the last annual report on Form 10-K have been condensed or omitted for the interim statements. Certain costs are estimated for the full year and allocated to interim periods based on the estimates of operating time expired, benefit received or activity associated with the interim period. Accordingly, such costs are subject to year-end adjustment. It is PGE's opinion that, when the interim statements are read in conjunction with the 2000 Annual Report on Form 10-K, and the other reports filed with the Securities and Exchange Commission since its 2000 Form 10-K was filed, the disclosures are adequate to make the information presented not misleading.

Reclassifications - Certain amounts in prior years have been reclassified to conform to current year presentation.

Note 2 - Income Taxes

Since its merger with Enron on July 1, 1997, PGE's federal income taxes have been a part of Enron's consolidated federal income tax return; PGE paid for its tax liabilities when it generated taxable income and was reimbursed for its tax benefits by Enron on a stand-alone basis. On May 7, 2001, Enron determined that PGE would no longer be a member of the Enron consolidated federal income tax return. In future tax years, PGE and its subsidiaries will file their own consolidated federal income tax return, and pay their own tax liability directly to the Internal Revenue Service. PGE and its subsidiaries will file their unitary state income tax returns in accordance with the appropriate state law. This will include filing their own unitary state income tax returns and paying their own state tax liabilities, as well as being included in some Enron and subsidiaries' unitary state income tax returns.

Note 3 - 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 have been 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 o f 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 consisted of before-tax credits of approximately $79 million in customer benefits related to the previous settlement of power contracts with two other utilities and 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 yea rs; 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.

Note 4 - Price Risk Management

PGE engages in both non-trading and trading activities in certain energy-related commodity contracts. Under SFAS No. 133, which was adopted on January 1, 2001, derivative instruments are recorded on the balance sheet as an asset or liability measured at fair value, with changes in the derivative's fair value 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.

Non-Trading Activities

As PGE's primary business is to serve its retail customers, it enters into non-trading electricity forward contracts and natural gas forward, swap and futures contracts to manage exposures to commodity price risks to achieve lower net power costs for customers. The Company recorded in the first half of 2001 an after-tax unrealized gain of $4 million in earnings on non-trading natural gas swaps in PGE's retail portfolio, including $5 million in the second quarter of the year.

Derivative activities in OCI for the three- and six-month periods ended June 30, 2001 are summarized in Note 5, Comprehensive Income. No amount was reclassified into earnings as a result of hedge ineffectiveness. Of the $35 million transition adjustment, gains totaling $10 million were reclassified into earnings in the first half of 2001, with an estimated $41 thousand loss expected to be reclassified to earnings in the remaining six months of the year. The Company estimates that of the ($12) million OCI balance at June 30, 2001, losses totaling $4 million are expected to be reclassified into earnings within the next twelve months. The actual amounts reclassified from OCI to earnings can differ as a result of market price changes.

The Financial Accounting Standards Board (FASB) concluded its consideration of an SFAS No. 133 implementation issue related to the interpretation and application of the "normal purchases and normal sales exception" to the electric utility industry's practice of "bookouts" and "net scheduling" of power contracts. PGE believes its electricity forward contracts meet the criteria for recording under the "normal purchases and normal sales" exception of SFAS No. 133.

Trading Activities

PGE's trading activities, which constitute a small portion of PGE's electric business, utilize electricity forward contracts and natural gas forward, swap and futures contracts to take advantage of price movements in electricity and natural gas to optimize the results of its operations. In the first half of 2001, PGE recorded in earnings an after-tax unrealized gain of $16 million on electricity forward contracts and natural gas forward contracts, swaps, and futures, including $8 million in the second quarter of the year.

Note 5 - Comprehensive Income

PGE's comprehensive income is as follows (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2001	2000	2001	2000
Net Income	$ 29	$ 25	$ 72	$ 64
Other comprehensive income:				
Unrealized gains on derivatives classified as cash flow hedges:				
Unrealized holding gain due to cumulative effect of change in accounting principle, net of related taxes of ($23)	-	-	35	-
Other unrealized holding losses arising during the period, net of related taxes of $30 and $27	(45)	-	(41)	-
Less reclassification adjustment for losses due to discontinuance of cash flow hedges, net of related taxes of $3 and $3 (a)	4	-	4	-
Less: reclassification adjustment for gains included in net income, net of related taxes of $1 and $7	(2)	-	(10)	-
Total	$ (43)	$ -	$ (12)	$ -
Total comprehensive income (loss)	$ (14)	$ 25	$ 60	$ 64

(a) Based upon the probability that the original forecasted transactions will not occur.

Note 6 - Receivables - California Wholesale Market

As of June 30, 2001, PGE had approximately $118 million of accounts receivable that may be affected by the financial condition of two major California utilities. Remaining payments totaling approximately $48 million were 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. SCE has made its scheduled monthly payments in 2001 under the termination agreement. In addition, balances of approximately $62 million and $8 million were owed the Company by the California Independent System Operator (ISO) and California Power Exchange (PX), respectively, for wholesale electricity sales made from November 2000 through February 2001, including limited sales made under federal order. The Company estimates the majority of this amount was for sales by the ISO and PX to SCE and Pacific Gas & Electric Company (PG&E).

On March 9, 2001, the PX filed for bankruptcy, and on April 6, 2001, PG&E filed a voluntary petition for relief under the provisions of Chapter 11 of the U.S. Bankruptcy Code. Pursuant to Chapter 11 of the U.S. Bankruptcy Code, PG&E retains control of its assets and is authorized to operate its business as a debtor in possession while subject to the jurisdiction of the Bankruptcy Court.

PGE is pursuing collection of all past due amounts. Management is continually assessing PGE's exposure relative to its California receivables and has established a credit reserve for amounts due under its wholesale electricity contracts.

The Company has retained legal counsel on the bankruptcy matter and has numerous options, including legal, regulatory, and other means to pursue collection of amounts ultimately not received. Due to uncertainties surrounding both the bankruptcy filing and the California power situation, management cannot predict the ultimate realization of these receivables.

Management believes that the outcome of this matter will not have a material adverse impact on the financial condition of the Company, but may have a material impact on the results of operations for future reporting periods.

Note 7 - Refunds on Wholesale Transactions

California

On March 9, 2001, the FERC issued an order directing 13 electricity suppliers, including PGE, to supply additional information regarding January 2001 and February 2001 wholesale power sales to California. The scope of the potential refund contemplated by the order is approximately $3.2 million applicable to PGE for wholesale electricity sales made in January and February during a limited hourly time frame. In accordance with the order, the Company responded with initial and subsequent filings containing information regarding the applicable sales. Refunds under this order are being determined in conjunction with a hearing held pursuant to the July 25, 2001 FERC order discussed below.

In a June 19, 2001 FERC order adopting a price mitigation program for 11 states within the Western Systems Coordinating Council area, the issue of refunds for spot market sales made between October 2, 2000 through June 20, 2001 was referred to a settlement judge. Subsequently, the settlement judge recommended to the FERC that the potential for refunds be extended and calculated for all hours during the period October 2, 2000 through June 20, 2001.

On July 25, 2001, the FERC issued an order establishing the scope of and methodology for calculating refunds related to non federally-mandated transactions in the spot markets operated by the Cal ISO and the PX. In addition, an evidentiary hearing proceeding was ordered to develop a factual record to provide the basis for the refund calculation, which will be made by the ISO and subject to review by PGE. The Company's potential refund obligation, using the suggested methodology, is currently estimated to be in the range of $20 to $30 million, with final determination to be made after FERC review of calculations filed by the ISO. PGE will have the opportunity to challenge the FERC's determination of the amount of any proposed refunds.

Pacific Northwest

In the July 25, 2001 order, the FERC called for a preliminary evidentiary hearing to explore whether there may have been unjust and unreasonable charges for spot market sales of electricity in the Pacific Northwest from December 25, 2000 through June 20, 2001. During this period, PGE both sold and purchased electricity in the Pacific Northwest. A procedural schedule issued August 2, 2001 provides for the submission of evidence, hearings, and testimony, with recommendations regarding refunds for the Pacific Northwest to be reported to the FERC within seven days from the end of the hearing.

Any refunds paid or received by PGE applicable to spot market electricity transactions on and after January 1, 2001 are eligible for inclusion in the calculation of net variable power costs under the Company's power cost mechanism. This could potentially mitigate the financial effect of any refunds made or received by the Company.

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

Note 8 - Credit Facilities and Debt

On June 13, 2001, PGE amended and restated its 364-day $100 million credit agreement with a group of commercial banks. The agreement provides for a 364-day extension and an increase to $200 million, with an annual facility fee of 0.10%. This facility, along with an existing $150 million credit facility maturing in July 2003, provides PGE with total committed credit lines of $350 million. The agreement was further amended on July 12, 2001 to allow for the issuance of letters of credit up to $100 million. PGE's credit facility will be used as backup for commercial paper and borrowings from commercial banks under uncommitted lines of credit, and will serve as the Company's primary source of liquidity. There are no changes to current debt covenants or other restrictions.

Portland General Electric Company and Subsidiaries

Management's Discussion and Analysis of Financial

Condition and Results of Operations

Results of Operations

The following review of PGE's results of operations should be read in conjunction with the Consolidated Financial Statements.

Due to seasonal fluctuations in electricity sales, as well as the volatility in prices of wholesale energy and natural gas, quarterly operating earnings are not necessarily indicative of results to be expected for calendar year 2001.

2001 Compared to 2000 for the Three Months Ended June 30

PGE earned $29 million in the second quarter of 2001 compared to $25 million in the second quarter of 2000. The effect of significantly higher prices for wholesale electricity sales was partially offset by higher power costs and increased operating expenses during the quarter.

Total operating revenues increased $401 million (93%) compared to the second quarter of 2000, due almost entirely to higher prices for energy sold in the wholesale market. Wholesale revenues increased $404 million (from $183 million to $587 million), as prices were more than five times higher than in last year's second quarter due to the combined effect of higher natural gas prices, below normal hydro conditions, and market forces within the region. Wholesale sales volume decreased 38% as available power purchases were used to replace lower hydro generation to meet second quarter retail load requirements. Retail revenues decreased $6 million on energy sales that decreased about 3% from last year's second quarter, as lower industrial usage, due to the Demand Buy Back program, and conservation more than offset an approximate 4,300 increase in the average number of retail customers served. Other operating revenues increased $3 million due largely to higher prices on sales of natural gas in excess of generation requirements.

Megawatt-Hours Sold (thousands)

	2001	2000
Retail	4,472	4,598
Wholesale	3,035	4,909

Purchased power and fuel costs increased $381 million (152%) due to significantly higher power prices. Due to both higher regional power and gas market prices, the average cost of firm power purchases increased more than four-fold from last year's second quarter. Combined with higher prices for spot market purchases, reduced hydro production, and increased thermal generation, PGE's average variable power cost more than tripled (for further information, see "Power Supply" in the Financial and Operating Outlook section). Partially offsetting the effect of the increased average cost of purchased power and fuel was an approximate 20% decrease in total system load, as both wholesale and retail energy sales decreased from last year's second quarter. In addition, a $10 million increase in unrealized gains on electricity trading contracts and trading and non-trading natural gas swaps, futures, and forward contracts further offset the effect of the increased average cost (see Note 4, Price Risk Management, in the Notes to Financial Statements for further information).

Company generation increased 44%, with increased combustion turbine and coal-fired generation partially offset by a 26% decrease in hydro production caused by lower stream flows. Total generation increased from 21% to 36% of PGE's total system requirement during the second quarter of 2001.

Megawatt/Variable Power Costs

	Megawatt-Hours (thousands)		Average Variable Power Cost (Mills/kWh)	
	2001	2000	2001	2000
Generation	2,827	1,967	19.6	14.5
Firm Purchases	4,500	7,175	111.7	25.0
Spot Purchases	491	628	177.2	74.6
Total Send-Out	7,818	9,770	83.6*	26.9*

(*includes wheeling costs)

Operating expenses (excluding purchased power and fuel, depreciation, and taxes) increased $6 million. Increased production expenses were incurred for boiler repairs and combustion turbine inspections at the Company's thermal generating plants in efforts to reduce the length of scheduled outages during the quarter. Higher expenses were also incurred in this year's second quarter for customer service and support activities, including those related to maintenance of the Company's customer information system, and for general administrative expenses, including the timing of allocated overhead costs from Enron. In addition, energy efficiency expenditures, deferred and amortized prior to October 1, 2000, are now expensed and recovered by additional revenues.

Depreciation and amortization expense increased $7 million, due primarily to a net increase in regulatory amortization, including the effect of the removal of certain regulatory liabilities from the balance sheet as part of last year's Trojan settlement agreement. In addition, credits recorded in the first quarter related to this year's power cost mechanism were reversed in the second quarter (for further information, see "Power Cost Mechanism" in the Financial and Operating Outlook section).

Taxes on operating income increased $3 million due to increased taxable income for the quarter.

2001 Compared to 2000 for the Six Months Ended June 30

PGE earned $72 million during the six months ended June 30, 2001, compared to earnings of $64 million in 2000. The results include a positive $11 million cumulative effect of a change in accounting principle resulting from the Company's adoption on January 1, 2001, of Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities" (see Note 4, Price Risk Management, in the Notes to Financial Statements for further information).

Income before the effect of the accounting change was $61 million, a $3 million decrease from the first six months of 2000. The effect of significantly higher prices for wholesale electricity sales was more than offset by higher power costs, increased operating expenses, and losses in the market value of trust owned life insurance assets.

Total operating revenues increased $770 million (93%) compared to the first half of 2000 due to higher prices for energy sold in the wholesale market. Wholesale revenues increased $771 million (from $296 million to $1,067 million), as prices rose more than five-fold from last year's first six months due to the combined effect of higher natural gas prices, below normal hydro conditions, and market forces within the region. Wholesale sales volume decreased 37% as available power purchases were used to replace lower hydro generation to meet retail load requirements in the first half of the year. Retail revenues decreased $8 million (2%) on energy sales that decreased about 2% from last year's first six months, as lower industrial usage due to the Demand Buy Back program, mild weather, and conservation more than offset an approximate 4,500 increase in the average number of retail customers served. Other operating revenues increased $7 million due to both higher prices and increased sales of natural gas, as the Company's Beaver turbine generating plant economically utilized oil during a portion of the first quarter of 2001.

Megawatt-Hours Sold (thousands)

	2001	2000
Retail	9,663	9,886
Wholesale	5,774	9,190

Purchased power and fuel costs increased $761 million (168%) due to significantly higher power prices. Due to both higher regional power and gas market prices, the average cost of firm power purchases increased more than four-fold from last year's first six months. Combined with higher prices for spot market purchases, reduced hydro production, and increased thermal generation, PGE's average variable power cost almost tripled (for further information, see "Power Supply" in the Financial and Operating Outlook section). Partially offsetting the effect of the increased average cost of purchased power and fuel was an approximate 19% decrease in total system load, as both wholesale and retail energy sales decreased from last year's first half. In addition, a $17 million increase in unrealized gains on electricity trading contracts and trading and non-trading natural gas swaps and forward contracts further offset the effect of the increased average cost (see Note 4, Price Risk Management, in the Notes to Financial Statements for further information).

Company generation increased 20%, with increased combustion turbine and coal-fired generation partially offset by a 30% decrease in hydro production caused by lower stream flows. Total generation increased from 26% to 37% of PGE's total system requirement during the first half of 2001.

Megawatt/Variable Power Costs

	Megawatt-Hours (thousands)		Average Variable Power Cost (Mills/kWh)	
	2001	2000	2001	2000
Generation	6,115	5,089	22.2	13.1
Firm Purchases	8,837	13,367	101.6	24.2
Spot Purchases	1,119	1,292	175.3	49.4
Total Send-Out	16,071	19,748	77.6*	23.8*

(*includes wheeling costs)

Operating expenses (excluding purchased power and fuel, depreciation, and taxes) decreased $3 million. In the first half of 2000, the Company recorded provisions of $2.4 million and $1.5 million, respectively, for deferred costs related to the proposed sale of its 20% interest in Units 3 and 4 of the Colstrip power plant and for increased insurance claims. (The Colstrip sale was denied by the OPUC and the Company is seeking rate recovery of certain related costs). In addition, lower expenses in this year's first half include $8 million in employee health insurance and other benefit costs, $2 million in outage repair and distribution maintenance due to milder weather, and $2 million in general administrative expenses. Partially offsetting these reductions was a $4 million increase for boiler repairs and combustion turbine inspections at the Company's thermal generating plants, and a $4 million increase in energy efficiency expenditures in this year's first half (such expenditures were d eferred and amortized prior to October 1, 2000 but are now expensed and recovered by additional revenues). Operating expenses for the first half of last year were reduced by a $5 million refund received upon PGE's termination of membership in Nuclear Electric Insurance Limited.

Depreciation and amortization expense increased $9 million, due primarily to the effect of the removal of certain regulatory liabilities from the balance sheet as part of last year's Trojan settlement agreement.

Other income (net of tax) decreased $4 million, primarily due to the loss in market value of trust owned life insurance assets. An approximate $3 million loss in the value of such assets is reflected in this year's first half, compared to a $6 million gain last year.

This was partially offset by an approximate $6 million increase in interest income, including that earned on the temporary investment of wholesale trading deposits and that related to the Enron merger credit and SCE contract termination, both of which were offset in last year's Trojan settlement agreement, with related interest now reflected in income.

An increase in interest on long-term debt and other, due to both interest on wholesale trading deposits and to the March 2000 issuance of $150 million in unsecured notes, was offset by reduced interest on a lower average level of commercial paper outstanding during the first half of 2001.

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.

A significant portion of cash from operations comes from depreciation and amortization of utility plant, charges which are recovered in customer revenues but require no current cash outlay. Changes in accounts receivable and accounts payable can also be significant contributors or users of cash.

Cash used in operating activities totaled $113 million in the first half of 2001, compared to $126 million provided in the same period last year. This was caused primarily by the repayment of $130 million in deposits received from wholesale electricity customers held at year-end 2000, as well as the payment of $59 million of such deposits in the first half of 2001; such payments were funded primarily by increased commercial paper borrowings. Increased purchases of fuel oil and stores material, major maintenance and overhaul expenditures at the Coyote Springs combustion turbine plant, and increased accounts receivable from wholesale electricity customers accounted for most of the remaining increase in cash used for operating activities.

Investing Activities consist primarily of improvements to PGE's distribution, transmission, and generation facilities. Capital expenditures in the first half of 2001 exceeded last year's first half primarily due to the continued expansion and improvement of PGE's distribution system to support new customers. In addition, costs of a new 24.5 megawatt combustion turbine plant and certain large transmission substation and production plant improvements were incurred in this year's first half.

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. During the first half of 2001, commercial paper borrowings increased $188 million, which was utilized primarily to refund deposits received from wholesale electricity customers in 2000 and to make deposits with such customers during the first six months of 2001. The Company paid $40 million in common stock dividends to its parent and $1 million in preferred stock dividends during the first half of 2001.

On June 13, 2001, PGE amended and restated its 364-day $100 million credit agreement with a group of commercial banks (see Note 8, Credit Facilities and Debt, in the Notes to Financial Statements for further information). In February 2001, the Company filed a $250 million shelf registration statement with the Securities and Exchange Commission, increasing PGE's long-term debt capacity to $300 million. PGE currently plans to issue long-term debt in the second half of 2001, as determined by market conditions and other factors, the proceeds from which will be used to refund fixed and variable rate securities, reduce commercial paper borrowings, and for other general corporate purposes.

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 June 30, 2001, PGE has the capability to issue preferred stock and additional First Mortgage Bonds in amounts sufficient to meet its anticipated capital requirements.

Financial and Operating Outlook

Restructuring

PGE filed a restructuring plan, including associated tariffs, with the OPUC in October 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 to energy suppliers by industrial and commercial customers, as provided for in State Senate Bill 1149 (SB1149), enacted in 1999. Under the plan, residential customers will be able to purchase electricity from a "portfolio" of options that will include a cost-of-service rate, a new renewable resource rate, and a market-based rate.

In accordance with a March 2000 accounting order from the OPUC, PGE is deferring incremental costs of implementing SB1149 for recovery in future electricity rates; at June 30, 2001, such costs totaled approximately $9 million.

In July 2001, Oregon's governor signed into law legislation that delays the implementation of SB1149 from October 1, 2001 until March 1, 2002. PGE is supportive of the delay as mutually beneficial to the Company and its customers, allowing additional time for customer communication, required infrastructure additions, and system testing and integration. Restructuring provisions of SB1149 are separate from PGE's requested rate increase (discussed below), which the Company expects to implement on October 1, 2001.

Because of the five-month delay, the OPUC is currently considering a revised decision date on the Company's Resource Plan, which was filed with the Commission in November 2000. Any delay in this decision could result in revisions to the Resource Plan.

General Rate Case

On July 16, 2001, a conference was held with the OPUC to address issues raised by the delay in the implementation of SB1149. The Company has previously entered into a stipulation with OPUC staff that addressed all issues other than return on equity and variable power costs. A schedule has been agreed to by the parties to the rate proceeding that provides for consideration of remaining issues, upon which the Commission is expected to issue an order in August 2001. The schedule provides for the implementation of new tariff rates on October 1, 2001.

PGE is working with parties to its current rate proceeding to develop a power cost mechanism for the period October 1, 2001 through December 31, 2002, replacing the current mechanism. PGE, Commission Staff, and other parties have stipulated to a methodology for the determination of variable power costs, including a power cost mechanism that will address the Company's exposure to uncertainty and volatility in prices of natural gas and electricity in the wholesale energy market. The Commission is expected to address the stipulation in the August 2001 order.

Power Cost Mechanism (January 1, 2001 - September 30, 2001)

As PGE's generation and long-term power contracts provide only a portion of its customers' load, the Company has relied increasingly upon short-term wholesale power purchase contracts and wholesale spot market purchases. To assure supply and reliability to its retail customers, PGE buys and sells power in a wholesale market in which prices have become increasingly volatile.

On February 20, 2001, the OPUC authorized PGE to defer, for future ratemaking treatment, any changes from net variable power costs which differ from a baseline approved by the Commission. Under the mechanism, PGE shares with its retail customers any changes in retail power costs outside of a pre-determined range, from a baseline amount of $176 million, for the period January through September 2001. PGE expects to recover, or refund, one-half (50%) of retail power costs that deviate from the baseline by more than $35 million, up to $56 million, and 90% of retail power costs that deviate from the baseline by more than $56 million.

In a subsequent proceeding, PGE will request the recovery (or refund) of the deferred amount in accordance with the mechanism described above. The amount expected to be recovered from, or refunded to, customers is included within unamortized regulatory assets or liabilities on the balance sheet and within depreciation and amortization expense on the income statement.

In the first half of 2001, PGE's net variable power costs, as calculated under terms agreed to with the OPUC, were approximately at the baseline; therefore, no charge or credit to retail customers was recorded. However, it is now expected that the effects of continued price volatility, coupled with the wholesale price mitigation program adopted by the FERC in June 2001, will likely result in net variable power costs exceeding pre-determined amounts specified in the mechanism. As a result, recovery of a portion of excess power costs from retail customers may be necessary. Any amount to be collected from, or refunded to, customers would be subject to events over the next three months and a review by the Commission.

Refunds on Wholesale Transactions

The FERC has issued an order directing certain electricity suppliers, including PGE, to supply information regarding wholesale power sales to California made in 2000 and 2001. Settlement discussions have taken place between such power suppliers, the state of California, and the FERC regarding potential refunds by suppliers. Such discussions did not resolve the issues and the FERC has now scheduled formal hearings to determine any potential refunds. In addition, the FERC has called for a preliminary evidentiary hearing to explore whether there may have been unjust and unreasonable charges for spot market sale of electricity in the Pacific Northwest from December 25, 2000 through June 20, 2001 (see Note 7, Refunds on Wholesale Transactions, in the Notes to Financial Statements for further information).

Wholesale Price Mitigation

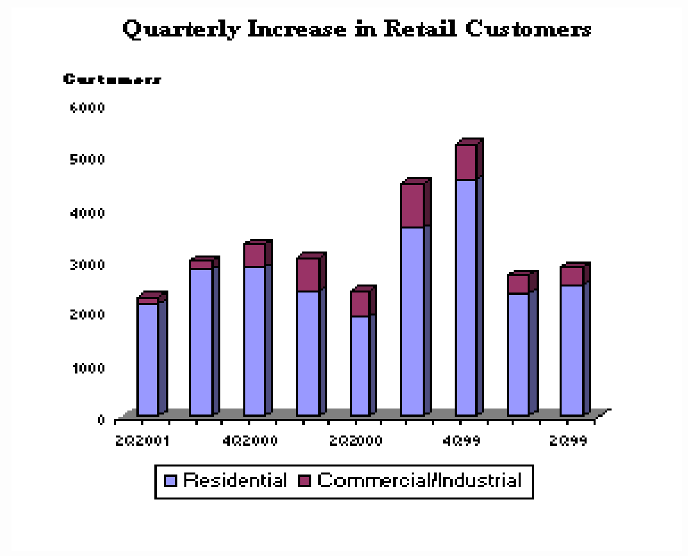
On June 19, 2001, the FERC adopted a price mitigation program for the power system serving 11 Western states, adopting a new benchmark formula that limits prices for spot power transactions at all times throughout the region through September 30, 2002. It applies to power generators, marketers, and investor-owned utilities under FERC jurisdiction as well as public power providers, municipal utilities, and electric cooperatives that use FERC-regulated transmission lines.

Under the program, a market clearing price, or ceiling, is set for wholesale electricity sold in the spot market coordinated by the California Independent System Operator; such price will also apply to markets in the other Western states. The ceiling price, reflecting specified fuel, operations, and maintenance costs, will be based upon the bid submitted by the highest cost gas-fired generating unit whose power is needed when reserves in California fall below 7 percent, triggering a Stage I supply emergency. No bid to sell power may exceed the clearing price as long as the reserve emergency is in place. When reserves again exceed 7 percent, removing the emergency, the ceiling price will drop to 85 percent of the highest hourly price in effect during the most recent Stage 1 reserve emergency. Because of increased credit risk, wholesale electricity sales to California are allowed a 10 percent surcharge.

On July 19, 2001, PGE filed with the FERC a formal request for a rehearing on its price mitigation program, in response to its potentially adverse consequences for citizens, utilities, power marketers, and generators in the Northwest. Such requested rehearing would address the FERC's methodology for the calculation of price mitigation controls instituted in its June 19, 2001 order. It also requests further consideration of the differences between the Northwest and California power markets, including differences in hydropower utilization and seasons of peak usage, in an effort to develop solutions that are both more fair and more likely to achieve reliable power supplies.

Retail Customer Growth and Energy Sales

Weather adjusted retail energy sales decreased by 2.6% for the six months ended June 30, 2001, compared to the same period last year. The decrease is partially attributable to the transfer of approximately 7,150 retail customers to two public utility districts in the third quarter of 2000, pursuant to the sale of a portion of PGE's service territory. Manufacturing sector energy sales decreased 3.1% due to the effect of the Demand Buyback program, in which PGE pays large customers to reduce their load during peak demand periods. Excluding the effect of the Demand Buyback program, manufacturing sector sales increased approximately 2% and total retail sales decreased about 1%. While commercial sales were flat, sales to residential customers decreased 4.1% in the first half of the year due primarily to conservation. PGE forecasts retail energy sales growth will remain flat for the remainder of 2001. (The accompany ing graph excludes the effect of the transfer of customers pursuant to the sale of a portion of PGE's service territory).



Residential Exchange Program

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 rate proposals, approval of which is anticipated in October 2001.

Power Supply

Hydro conditions in the region are substantially below normal this year. Volumetric water supply measurements for the Pacific Northwest, prepared by the Northwest River Forecast Center in conjunction with the Natural Resources Conservation Service and other cooperating agencies, indicate the January-to-July runoff at 54.9% of normal, compared to 92% of normal last year.

PGE generated 37% of its total load requirement in the first half of 2001, with hydro generation comprising 6% of the total requirement; short- and long-term purchases were utilized to meet the remaining load. The Company's ability to purchase power in the wholesale market, along with its base of thermal and hydroelectric generating capacity, currently provides 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, uncertainty over restructuring deregulation has discouraged construction of new generating plants.

Higher prices for natural gas, weather conditions in California and the Southwest, a reduction in surplus generation, and fish protection spill requirements affecting hydro generation, have increased both price and demand pressure on available resources during the past year. Recent changes however, have resulted in significantly lower market prices for both natural gas and electricity; these include additional generation from both new plants and from those returning to service, moderating weather conditions, additional gas supplies, and federal price mitigation.

A new 24.5 megawatt combustion turbine plant, to be operated during peak demand periods, has been constructed at the site of the Company's Beaver plant and became operational on August 3, 2001. In addition, the Company on February 27, 2001 filed a "Notice of Intent" with the Energy Facility Siting Council to build a new 650 megawatt gas turbine plant at the Beaver site. The required site certificate application and air contamination discharge permit are in the process of completion by the Company.

PGE supplements its current power supply capability through the use of forward contracts for the purchase of electricity, expanded energy efficiency programs, a Demand Buyback program which pays large customers to reduce load during peak demand periods, and increased public information activities related to conservation. In addition, the Company continues to make improvements and upgrades to increase the capacity of its generating plants and also participates in wind power and biogas projects to augment its current power supply resources and capability.

Financial Risk Management

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 risk are recognized in purchased power and fuel expense, or in wholesale revenue (see Note 4, Price Risk Management, in the Notes to Financial Statements for further information).

The use of derivative commodity instruments may expose the Company to market risks arising from adverse changes in commodity prices and the ability of counterparties to meet their commitments to PGE. The Company actively manages these risks to ensure compliance with its risk management policies.

In 2000 and in the first half of 2001, PGE's market risk profile has been impacted by 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 June 30, 2001.

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 risks, it will consider such instruments in the future, as necessary.

RTO West and Independent Transmission Company

In April 2001, PGE and five other regional utilities received conditional approval from the FERC to form TransConnect, an independent transmission company that will participate in RTO West, a regional non-profit transmission organization that would operate the transmission system in the Pacific Northwest, Nevada, and parts of neighboring states. Pursuant to such approval, TransConnect can initially own or lease the high voltage transmission facilities currently held by its participants.

Five of the original six TransConnect participants plan to file a preliminary tariff with the FERC in September 2001. RTO West currently plans a "Stage II" filing in December 2001 that will provide further details on items such as congestion management, pricing, planning, and systems integration issues. FERC has also requested RTO West to propose by December 1, 2001 a framework and timetable for formation of a West-wide RTO.

On July 12, 2001, the FERC expressed its preference for the development of single RTO's in the Northeast, Southeast, Midwest, and West. PGE and other participants in RTO West and TransConnect are continuing to evaluate the contents of the FERC orders as efforts continue to develop plans creating these organizations. Decisions related to the formation of RTO West and TransConnect will continue to be subject to approvals by state and federal regulatory agencies and individual company boards of directors.

New Accounting Standard

In July 2001, the FASB issued SFAS No. 142, "Goodwill and Other Intangible Assets". SFAS No. 142, which must be applied in fiscal years beginning after December 15, 2001, modifies the accounting and reporting of goodwill and other intangible assets. PGE has no goodwill.

Under SFAS No. 142, entities are required to determine the useful life of other intangible assets and amortize them over this period. If the useful life is determined to be indefinite, no amortization is to be recorded. However, those intangible assets with indefinite lives are required to be tested for impairment in a manner similar to that provided by SFAS No. 142 for goodwill, which is by application of a fair-value-based analysis. For intangible assets recognized prior to the adoption of SFAS No. 142, the useful life is to be reassessed. PGE is in the process of evaluating the application of SFAS No. 142 pertaining to other intangible assets.

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, but are not limited to, 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 natural gas, and adverse weather conditions during the periods covered by the forward-looking statements.

PART II

Portland General Electric Company and Subsidiaries

Other Information

Item 1. Legal Proceedings

For further information, see PGE's report on Form 10-K for the year ended December 31, 2000.

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

To provide the OPUC time to consider the issues raised on the URP's complaint challenging PGE's application for approval of the accounting and ratemaking elements of the Trojan settlement, PGE has requested, and the Oregon Supreme Court has granted, an extension from April 16, 2001 until after October 1, 2001 for the Court's consideration of the dismissal, as moot, of the cases.

Item 6. Exhibits and Reports on Form 8-K

a. Exhibits

None.

b. Reports on Form 8-K

None.

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)

August 10, 2001	By:	/s/ James J. Piro
		James J. Piro
		Senior Vice President
		Chief Financial Officer and Treasurer
August 10, 2001	By:	/s/ Kirk M. Stevens
		Kirk M. Stevens
		Controller and Assistant Treasurer