



Portland General Electric Company
Trojan ISFSI
71760 Columbia River Hwy
Rainier OR 97048

June 22, 2006

VPN-007-2006

Trojan ISFSI
Docket 72-17
License SNM-2509

ATTN: Document Control Desk
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

Annual Financial Reports for Fiscal Year 2005

In accordance with 10 CFR 72.80(b), enclosed are the Fiscal Year 2005 Annual Financial Reports for Portland General Electric Company, Eugene Water and Electric Board, and PacifiCorp.

If you have any questions regarding this submittal, please contact Mr. Jay Fischer of my staff at (503) 556-7030.

Sincerely,

Stephen M. Quennoz
Vice President, Power Supply

Enclosures

- c: T. M. Stoops, ODOE
Director, DNMS, NRC Region IV
C. M. Regan, NRC, NMSS, SFPO (w/o enclosures)
K. D. Beeson, EWEB (w/o enclosures)
E. M. Burton, PacifiCorp (w/o enclosures)
R. N. Sherman, BPA (w/o enclosures)

AMSD/
MOU



Portland General Electric

FORM 10-K

ANNUAL REPORT

For The Year Ended December 31, 2005

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2005

OR

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

For the Transition period from _____ to _____

Commission File Number 1-5532-99

PORTLAND GENERAL ELECTRIC COMPANY

(Exact name of registrant as specified in its charter)

Oregon
(State or other jurisdiction of
incorporation or organization)

93-0256820
(I.R.S. Employer
Identification No.)

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

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

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

<u>Title of each class</u>	<u>Name of each exchange on which registered</u>
None	

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

<u>Title of each class</u>
Portland General Electric Company 7.75% Series, Cumulative Preferred Stock, no par value

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes ___ No X

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes ___ No X

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes X No ___

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. X

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☐

Accelerated filer ☐

Non-accelerated filer ☒

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes ___ No X

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

Number of shares of Common Stock outstanding as of February 28, 2006: 42,758,877 shares of common stock, \$3.75 par value. (All shares are owned by Enron Corp.)

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DEFINITIONS

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

<u>Abbreviations or Acronyms</u>	
AFDC	Allowance For Funds Used During Construction
Bankruptcy Court	United States Bankruptcy Court for the Southern District of New York
Beaver	Beaver Combustion Turbine Plant
Boardman	Boardman Coal Plant
BPA	Bonneville Power Administration
Chapter 11 Plan	Fifth Amended Joint Plan of Affiliated Debtors Pursuant to Chapter 11 of the United States Bankruptcy Code, dated January 9, 2004 and as thereafter amended and supplemented from time to time
Colstrip	Colstrip Units 3 and 4 Coal Plant
Coyote Springs	Coyote Springs Unit 1 Generating Plant
CUB	Citizens' Utility Board
Debtors	Enron Corp. and its reorganized debtor subsidiaries under the Chapter 11 Plan
DEQ	Oregon Department of Environmental Quality
Dth	Decatherm = 10 therms = 1,000 cubic feet of natural gas
EFSC	Energy Facility Siting Council
EITF	Emerging Issues Task Force of the Financial Accounting Standards Board
ESS	Energy Service Supplier
EPAct 2005	Energy Policy Act of 2005
Enron	Enron Corp., as reorganized debtor pursuant to its Supplemental Modified Fifth Amended Joint Plan of Affiliated Debtors Pursuant to Chapter 11 of the Bankruptcy Code, confirmed by the United States Bankruptcy Court For The Southern District of New York (Case No. 01-16034) on July 15, 2004 and effective November 17, 2004
EPA	Environmental Protection Agency
ERISA	Employee Retirement Income Security Act of 1974
ESA	Endangered Species Act
FERC	Federal Energy Regulatory Commission
Financial Statements	Consolidated Financial Statements of Portland General Electric Company included in Part II, Item 8 of this report
IRS	Internal Revenue Service
kWh	Kilowatt-hour

DEFINITIONS

Abbreviations or Acronyms

MW	Megawatt
MWa	Average megawatts
MWh	Megawatt-hour
NRC	Nuclear Regulatory Commission
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange, Inc.
OPUC or the Commission	Public Utility Commission of Oregon
PBGC	Pension Benefit Guaranty Corporation
PGE or the Company	Portland General Electric Company
PUHCA 1935	Public Utility Holding Company Act of 1935
PUHCA 2005	Public Utility Holding Company Act of 2005
RVM	Resource Valuation Mechanism
SEC	Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board
Trojan	Trojan Nuclear Plant
URP	Utility Reform Project
USDOE	United States Department of Energy
VEBA	Voluntary Employee Beneficiary Association
WECC	Western Electricity Coordinating Council

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Part I

Item 1. Business

General

PGE, incorporated in 1930, is a single, integrated electric utility engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the State of Oregon. PGE also sells electricity and natural gas in the wholesale market to utilities and power marketers located throughout the western United States. PGE's service area is located entirely within Oregon and includes 52 incorporated cities, of which Portland and Salem are the largest, within a state-approved service area allocation of approximately 4,000 square miles. PGE estimates that at the end of 2005 its service area population was approximately 1.5 million, comprising about 43% of the state's population. The Company added approximately 13,000 retail customers during 2005, and at December 31, 2005 served approximately 780,000 retail customers.

On July 2, 1997, Portland General Corporation (PGC), the former parent of PGE, merged with Enron Corp., with Enron continuing in existence as the surviving corporation and PGE operating as a wholly owned subsidiary of Enron. On December 2, 2001, Enron, along with certain of its subsidiaries, filed to initiate bankruptcy proceedings under Chapter 11 of the federal Bankruptcy Code. PGE was not included in the filing. For further information, see "Enron Bankruptcy" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

In accordance with the Fifth Amended Joint Plan of Affiliated Debtors Pursuant to Chapter 11 of the United States Bankruptcy Code, dated January 9, 2004 and as thereafter amended and supplemented from time to time (Chapter 11 Plan), Enron plans to distribute PGE common stock to creditors of Enron and its reorganized debtor subsidiaries (Debtors) holding allowed claims. Current PGE common stock will be cancelled and 62,500,000 shares of new PGE common stock without par value will be distributed over time to the Debtors' creditors. Initially, PGE will issue at least 30 percent of the new PGE common stock to Debtors' creditors holding allowed claims, with the remainder issued to a Disputed Claims Reserve (the DCR) where it will be held to be released over time to the Debtors' creditors holding allowed claims in accordance with the Chapter 11 Plan. Following the issuance of the new PGE common stock, expected to take place on or about April 3, 2006, PGE will no longer be a subsidiary of Enron. Distribution of new PGE common stock has been approved by the required regulatory agencies, including the OPUC and the FERC. However, the City of Portland, Oregon has appealed the OPUC decision to the Marion County Circuit Court and the Oregon Court of Appeals, and the Utility Reform Project has filed a motion for reconsideration by the OPUC. For further information, see "Future Ownership of PGE" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

As of December 31, 2005, PGE had 2,620 employees. This compares to 2,644 and 2,687 employees at December 31, 2004 and 2003, respectively. A total of 846 employees are covered under agreements with Local Union No. 125 of the International Brotherhood of Electrical Workers. Such agreements cover 829 employees for a five-year period effective from March 1, 2004 through February 28, 2009. In addition, 17 employees at Coyote Springs are covered under an agreement effective from September 1, 2001 through August 1, 2006.

Customers and Operating Revenues

Retail

PGE serves a diverse retail customer base. Residential, the largest customer class, comprises about 88% of the Company's total number of customers, with the remainder comprised largely of commercial customers. At year-end 2005, PGE served 257 large commercial and industrial customers. Residential demand is sensitive to the effects of weather, with revenues highest during the winter heating season. Commercial and industrial customer classes are not dominated by any single industry. While the 20 largest customers constitute about 13% of total retail revenues, they represent 9 different commercial and industrial groups, including high technology, paper manufacturing, metal fabrication, communications, health services, and governmental agencies. No single customer represents more than 5% of PGE's total retail load or 4% of total retail revenues.

Total retail revenues and MWh energy sales decreased from 2004, reflecting both a decrease in amounts recovered from customers related to power cost adjustment mechanisms in effect in prior years, as well as an increase in commercial and industrial customers who have chosen to purchase their energy requirements from electricity service suppliers (ESSs). PGE continues to serve these customers by delivering the energy purchased from ESSs. These decreases were partially offset by a 2005 price adjustment to reflect an increase in variable power costs. For further information, see "Results of Operations" and "Resource Valuation Mechanism" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

Wholesale (Non-Trading)

PGE participates in the wholesale marketplace in order to balance its supply of power to meet the needs of its retail customers, manage risk, and administer its current long-term wholesale contracts. Such participation includes power purchases and sales resulting from economic dispatch decisions for its own generation, which allows PGE to secure reasonably priced power for its customers. Interconnected transmission systems in the western states serve utilities with diverse load requirements, which allows the Company to purchase and sell electricity within the region depending upon the relative price and availability of power, water conditions, and seasonal demand.

Non-trading wholesale electricity sales related to activities to serve retail load requirements comprised about 8% and 7% of total operating revenues in 2005 and 2004, respectively. Most of PGE's non-trading wholesale sales are to utilities and power marketers and are predominantly short-term. The Company may net purchases and sales with the same counterparty rather than simultaneously receiving and delivering physical power. These net transactions are also referred to as "book outs." Only the net amount of those purchases or sales required to fulfill retail and wholesale obligations are physically settled.

Other Operating Revenues

Other operating revenues includes sales of natural gas in excess of generating plant requirements and revenues from transmission services, pole contact rentals, and certain other electric services to customers. PGE's energy trading activities, results of which were reflected in Other operating revenues, were discontinued in early 2005.

The following table summarizes Operating Revenues and Energy Sold and Delivered for the years indicated.

	2005		2004		2003	
	Amount	%	Amount	%	Amount	%
Operating Revenues (Millions)						
Retail Sales						
Residential	\$ 593	46%	\$ 585	46%	\$ 555	43%
Commercial	505	40%	502	40%	500	39%
Industrial	178	14%	176	14%	228	18%
Total - Retail Sales	1,276		1,263		1,283	
Direct Access Customers ^(a)						
Commercial	1	-	2	-	-	-
Industrial	-	-	5	-	-	-
Tariff Revenues	1,277	100%	1,270	100%	1,283	100%
Accrued Revenues	28		48		45	
Total Retail Revenues	1,305		1,318		1,328	
Wholesale (Non-Trading) ^(b)	116		107		393	
Other Operating Revenues:						
Trading Activities - net	-		1		2	
Other	25		28		29	
Total Operating Revenues	\$ 1,446		\$ 1,454		\$ 1,752	
Energy Sold and Delivered (Thousands of MWhs)						
Retail Energy Sales						
Residential	7,323	39%	7,270	39%	7,099	39%
Commercial	7,069	38%	7,247	39%	7,190	39%
Industrial	3,148	17%	3,247	18%	4,137	22%
Total - Retail Energy Sales	17,540		17,764		18,426	
Delivered to Direct Access Customers ^(a)						
Commercial	400	2%	159	1%	-	-
Industrial	814	4%	617	3%	-	-
Total Retail Energy Deliveries	18,754	100%	18,540	100%	18,426	100%
Wholesale (Non-Trading) ^(b)	2,094		2,539		9,966	
Trading Activities	815		9,699		13,551	
Total Energy Sold and Delivered	21,663		30,778		41,943	

(a) Under Oregon's electricity restructuring law, certain commercial and industrial customers have chosen to be served by an ESS for their energy needs, beginning in 2004. Although the energy is purchased from an ESS, PGE delivers the energy to these customers and bills them a distribution service charge. Retail revenue can fluctuate for Direct Access Customers as a result of "transition adjustments" reflecting the difference between the cost and market of PGE's power supply portfolio.

(b) Wholesale (Non-Trading) revenues and energy sales indicated above exclude those activities that were "booked out" (not physically settled), reflecting requirements of EITF 03-11, which became effective on October 1, 2003. Excluded amounts are \$536 million and 9,523 thousand MWhs for 2005, \$296 million and 6,802 thousand MWhs for 2004, and \$90 million and 2,116 thousand MWhs for the fourth quarter of 2003 (prior periods were not reclassified). For further information, see Note 1, Summary of Significant Accounting Policies, in the Notes to Financial Statements.

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

Regulation

General

PGE is subject to the jurisdiction of the OPUC, comprised of three members appointed by Oregon's governor to serve non-concurrent four-year terms. The Commission approves the Company's retail prices and establishes conditions of utility service. The OPUC's obligation under Oregon law is to ensure that the prices and terms of service are fair, non-discriminatory, and provide PGE an opportunity to earn a fair return on its investment. In addition, the Commission regulates the issuance of stock and long-term debt, prescribes the system of accounts to be kept by Oregon utilities, and reviews applications to sell utility assets and engage in transactions with affiliated companies.

Certain activities of PGE are also subject to the jurisdiction of the FERC. The Company is a "licensee" and a "public utility," as those terms are used in the Federal Power Act, and is subject to regulation by the FERC as to accounting policies and practices, licensing of hydroelectric projects, transmission services, wholesale sales, issuance of short-term debt, and other matters. In addition, PGE's interest in a natural gas pipeline is subject to the FERC's jurisdiction. Under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978, the FERC's authority includes matters related to extension, enlargement, safety, and abandonment of jurisdictional pipeline facilities, as well as transportation rates and accounting for interstate natural gas commerce. The Energy Policy Act of 2005 (EPA 2005) expanded the FERC's authority with respect to holding companies, effective February 8, 2006. The FERC now has new authority to review proposed mergers and acquisitions to prevent cross-subsidization and the encumbrance of utility assets, as necessary for the protection of utility customers. As a subsidiary of a registered holding company (Enron), PGE had been subject to regulation by the SEC with respect to several activities under PUA 1935, which has now been repealed. For further information, see "Energy Policy Act of 2005" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

Construction of new thermal generating facilities requires a permit from the EFSC.

The NRC regulates the licensing and decommissioning of nuclear power plants. In 1993, the NRC issued a possession-only license amendment to PGE's Trojan operating license, and in early 1996 the NRC and EFSC approved the Trojan Decommissioning Plan, which has allowed PGE to proceed in decommissioning the plant. The NRC approved the completed transfer of spent nuclear fuel from the Trojan spent fuel pool to a separately licensed dry cask storage system that will house the nuclear fuel on the plant site until permanent storage is available. PGE completed the radiological decommissioning of the Trojan site in December 2004 pursuant to an NRC-approved License Termination Plan, with the plant's Facility Operating License terminated by the NRC in May 2005. Spent fuel storage activities will continue to be subject to NRC regulation until all nuclear fuel is removed from the site, decontamination is completed, and the storage installation is fully decommissioned. The Oregon Department of Energy also monitors Trojan. For further information, see "Nuclear Decommissioning" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

Regulatory Matters

Retail Customer Choice Program

Oregon's customer choice program, implemented in 2002 as part of the state's electricity restructuring law, provides all commercial and industrial customers of the two large investor-owned utilities in Oregon direct access to competing ESSs. In addition, cost-of-service and market price options are offered to these customers. Residential and small commercial and industrial customers can purchase electricity from PGE from a "portfolio" of rate options that include a basic cost-of-service rate, a time-of-use rate, and renewable resource rates. The program further provides for a "transition adjustment" for non-residential customers that choose to purchase energy at market prices from investor-owned utilities or from ESSs. Such charges or credits reflect the above-market or below-market cost, respectively, of energy resources owned or purchased by the utility and are designed to ensure that such costs or benefits do not unfairly shift to the utility's remaining energy customers.

In 2005, the three ESSs registered to transact business with PGE served a total of 25 customers with a total average load of approximately 150 MWa, representing about 11% of PGE's non-residential load and 7% of the Company's total retail load. In addition, a total of 59 commercial and industrial customers were receiving service from PGE under market-based pricing options at the end of 2005. Approximately 40,000 customers have chosen renewable energy options and approximately 1,800 customers have chosen the time of use option.

PGE also offers an option by which certain large non-residential customers may, for a minimum three-year or five-year term, elect to be removed from cost of service pricing, with energy supplied by an ESS or at a daily market rate by PGE. Two customers, with a load of approximately 10 MWa, have chosen the five-year option; one began receiving service from PGE in 2003 and the other began receiving service from an ESS in 2004.

The restructuring law also provides for a 10-year Public Purpose Charge, equal to 3% of retail revenues, designed to fund cost-effective conservation measures, new renewable energy resources, and weatherization measures for low-income housing. In addition, the law provides for low-income electric bill assistance.

In accordance with the restructuring law and an order from the OPUC, PGE deferred certain costs related to implementation of the restructuring plan for recovery in electricity prices. Recovery of these costs is continuing, with unrecovered costs totaling approximately \$16 million at December 31, 2005.

PGE continues to operate as a cost-based regulated electric utility, for which revenue requirements are determined based upon the cost to serve customers, including an appropriate rate of return to the Company, and remains obligated to provide full ("bundled") service to all of its customers. PGE's 2001 general rate filing with the OPUC was based upon this cost-of-service model. At this time, the large majority of PGE's customers continue to take service under rate tariff schedules determined by the cost of service.

While PGE continues to meet the criteria of SFAS No. 71 and currently applies its provisions to reflect the effects of rate regulation in its financial statements, the Company periodically assesses the applicability of the statement to its business, or separable portions thereof. These assessments consider both the current and anticipated future rate environment and related accounting guidance, as outlined in SFAS No. 101, Regulated Enterprises - Accounting for the Discontinuation of Application of SFAS No. 71, and EITF Issue 97-4, Deregulation of the Pricing of Electricity - Issues Related to the Application of SFAS No. 71 and SFAS No. 101.

Federal Wholesale and Transmission Regulation

In April 1998, the FERC granted PGE authority to sell wholesale power at market-based rates. In May 2005, following review of an updated market power analysis submitted by the Company (required of jurisdictional utilities), the FERC granted reauthorization of PGE's market-based rate authority for the period 2005-2008.

In 1999, the FERC issued Order No. 2000 in a continued effort to more efficiently manage transmission, create fair pricing policies, and encourage competition by providing equal access to the nation's electric power grids. The order requires all owners of electricity transmission facilities to file a proposal to join a Regional Transmission Organization (RTO) or provide reasons that prevent such a filing. In response to this order, the Bonneville Power Administration (BPA) and certain western utilities, including PGE, filed an initial proposal with the FERC to form RTO West, a regional non-profit transmission organization that would operate the transmission system and manage pricing in the Pacific Northwest and portions of other western states. In March 2004, RTO West was renamed Grid West.

Grid West currently operates as a nonprofit membership corporation engaged in development work for future operation as an independent transmission provider that will manage the use and expansion of the region's interconnected transmission system. It responds to the need for greater coordination of regional transmission planning, expansion, and investment activities, and would address identified problems and facilitate changes in the structure of regional power markets. Although Grid West would manage many of the operating functions related to regional transmission facilities, ownership of the facilities would not change and existing transmission rights would be retained. Current members of Grid West include the region's major transmitting utilities, generators, power marketers, transmission dependent utilities, end-use consumers, states, tribes, and public interest groups. BPA has withdrawn from the Grid West development process. As a major transmitting utility, PGE continues to participate in Grid West and monitor its development process, although there remains uncertainty regarding the future of the organization. The Company is also participating in a parallel effort, led by BPA, to enhance the operations of the regional transmission system.

EPA 2005 was signed into law on August 8, 2005. The new law repealed PUHCA 1935 and significantly revised the Federal Power Act and Natural Gas Act. The law gives the FERC increased statutory authority to implement its stated goals, including mandatory transmission and reliability standards and enhanced oversight of power and transmission markets (including protection against market manipulation). It enacted tax incentives for the development of renewable and cleaner-fuel electric generating resources and for other electric and gas related purposes and substantially changed the qualifying facility provisions of the Public Utility Regulatory Policies Act of 1978 (PURPA). PGE does not expect EPA 2005 to have a material impact on the Company's operations or financial results.

Retail Rate Changes

PGE filed a general rate case in March 2006 for consideration by the OPUC, with rate adjustments expected to become effective in 2007. PGE's last general rate case was filed in October 2000, with authorized price changes effective on October 1, 2001. Pursuant to a tariff adopted in the 2001 case, PGE annually updates its forecast of net variable power costs. Based on such updates, the OPUC authorized changes in PGE's retail prices for each of the years 2003 through 2006. For further information, see "General Rate Case" and "Resource Valuation Mechanism" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

Integrated Resource Plan

PGE's Integrated Resource Plan (IRP), required by the OPUC, describes the Company's strategy to meet the electric energy needs of its customers, with an emphasis on supply reliability, price stability, risk reduction, and cost effectiveness. Planning for future resources is guided by PGE's objective to balance its load requirements against supply from its own generating resources and mid- to long-term power contracts.

PGE is continuing the process to procure approximately 790 MWa in additional energy resources, as recommended in the Company's Integrated Resource Final Action Plan, which was acknowledged by the OPUC in July 2004. Resource acquisitions through 2005 consist of a ten-year purchase agreement for 93 MWa, beginning in 2006, a thirty-year purchase power agreement for approximately 27 MWa (75 MW capacity) of wind generated power, which began in December 2005, and two five-year agreements, consisting of a 25 MW on-peak tolling agreement that began in January 2005, and a power purchase agreement for 25 MWa, beginning in late 2006. The Company has also entered into capacity agreements totaling 400 MW, extending from early 2005 to 2011.

PGE is in the process of constructing Port Westward, a 350 MWa natural gas-fired plant currently planned for completion in the first quarter of 2007. The new plant is expected to have a total capacity of approximately 400 MW, including 25 MW from duct firing capability. Other planned acquisitions consist of approximately 38 MWa (120-125 MW capacity) of additional wind generation, 60 MWa from upgrades to existing plants and contract extensions, and short-term market acquisitions of 125 MWa. In addition, PGE is proceeding with the acquisition of approximately 30-35 MW of additional dispatchable standby generation. The IRP also includes 55 MWa in savings from energy efficiency measures funded by the Energy Trust of Oregon.

PGE has initiated all power supply acquisitions contained in its Final Action Plan and is continuing negotiations to complete its targeted acquisition of wind energy.

The OPUC's 2004 order acknowledging PGE's Final Action Plan requires that, in addition to specific energy resource acquisitions, the Company address constraints on competitive renewable development in the region, work with BPA and others to develop transmission capacity that provides for access to additional wind (and other) resources at a reasonable price, and demonstrate that the Company has taken measures to acquire, option, or retain cost effective transmission capacity. PGE is actively engaged in regional discussions regarding constraints to competitive renewable development and is evaluating various transmission options that would result in additional capacity.

At the request of the Company, the OPUC agreed that, due to the continuing execution of the current Integrated Resource Final Action Plan, no IRP for the year 2005 was required, with PGE's next filing to be submitted by year-end 2006.

New Oregon Law - Utility Rate Treatment of Income Taxes

Oregon Senate Bill 408, a new law passed by the 2005 Oregon Legislature that became effective on September 2, 2005, seeks to more closely match amounts collected for income taxes under the ratemaking process with income taxes paid to taxing authorities by investor-owned utilities or their consolidated group. PGE is participating in the Commission's comprehensive rule-making process to implement the new law. In October 2005, PGE filed a report, as required by the new law, on taxes "collected" and "paid" (as defined under the temporary rules and Senate Bill 408) for the years 2002-2004. Under the law, however, the first rate adjustment applies only to taxes paid and amounts collected from customers beginning in 2006. In December 2005, Oregon's Attorney General issued an opinion that provides guidelines for the implementation of the law. There is considerable uncertainty regarding several provisions of the law and the Company continues to evaluate its potential effects. For further information, see "New Oregon Law - Utility Rate Treatment of Income Taxes" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

Governmental Actions

City of Portland Investigation

In September 2005, the Portland City Council approved a resolution directing the City Attorney and City staff to obtain from PGE information regarding the collection and payment of utility income taxes. The City has stated that it believes its City Charter provides it with authority for this request. PGE voluntarily provided extensive financial and operational data to the City. The City has since broadened its inquiry to include PGE's power trading activities in 2000 and 2001 and has requested that PGE provide many additional documents and records. PGE has determined that there are a number of legal and practical issues concerning the City's request for additional information, and has declined to provide any additional data to the City while those issues remain unresolved.

Competition and Marketing

General

Restructuring of the electric industry has slowed at both the national level and in the Pacific Northwest. PGE continues to maintain its commitment to service excellence while providing increased choices for its retail customers.

Retail Competition and Marketing

PGE conducts retail electric operations exclusively in Oregon within a state-approved service area. Competitors within the Company's service territory include the local natural gas company, which competes for the residential and commercial space and water heating market, and fuel oil suppliers, which compete primarily for residential space heating customers. In addition, commercial and industrial customers are allowed direct access to competing electricity service suppliers in accordance with Oregon's electricity restructuring law, related regulations, and PGE's tariff; there is no other retail competition from electricity providers. PGE currently offers all customers regulated cost of service and other pricing options. The Company does not operate as an electricity service supplier.

Wholesale Competition and Marketing

PGE participates in the wholesale energy marketplace in order to manage its power supply risks and acquire the necessary electricity and fuel to meet the needs of its retail customers and administer its current long-term wholesale contracts. The amount of surplus electric generating capability in the western United States, the amount of annual snow pack and its impact on hydro generation, the number and credit quality of wholesale marketers and brokers participating in the energy trading markets, the availability and price of natural gas as well as other fuels, and the availability and pricing of electric and gas transmission all contribute to and have an impact on the wholesale price and availability of electricity. The Company currently has authority under its FERC tariff to charge market-based rates for wholesale energy sales.

Power Supply

To meet its customers' energy needs, PGE relies upon its existing base of generating resources, long-term power contracts, and short-term purchases that together provide flexibility to respond to consumption changes and Oregon's electricity restructuring law. Short-term purchases include both spot and term purchases for periods of one year or less in duration.

Northwest hydro conditions have a significant impact on the region's power supply, with water conditions significantly impacting PGE's cost of power and its ability to economically displace more expensive thermal generation and spot market power purchases. Current forecasts indicate near normal hydro conditions for 2006.

In addition, natural gas and coal, used to fuel the Company's thermal generating plants, are subject to price volatility. PGE uses natural gas forward, swap, option, and futures contracts to manage its exposure to volatility in natural gas prices and will continue to monitor its exposure to changing prices for coal and natural gas.

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

Generating Capability

PGE's existing hydroelectric, coal-fired, and gas-fired plants are important resources for the Company, providing 1,973 MW of generating capability (see Item 2. - "Properties" for a full listing of PGE's generating facilities). The Company's lowest cost generating resources are its five FERC-licensed hydroelectric projects that incorporate eight powerhouses on the Clackamas, Sandy, Deschutes, and Willamette rivers in Oregon. For further information, see "Hydro Relicensing" in Item 2. - "Properties".

PGE's Integrated Resource Final Action Plan, acknowledged by the OPUC in July 2004, includes the construction of a 400 MW natural gas-fired plant at the Company's Port Westward site. Construction of the plant began in February 2005, with completion expected in the first quarter of 2007.

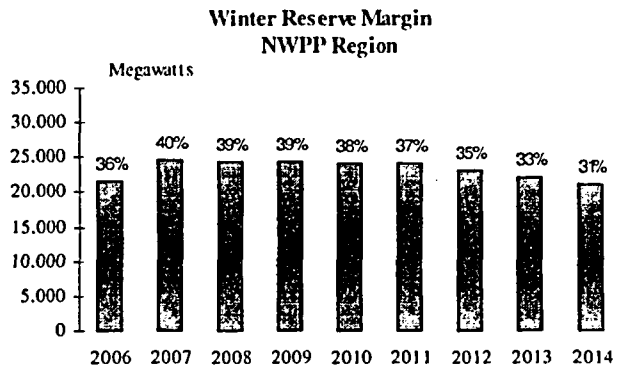
Purchased Power

PGE supplements its own generation with long-term and short-term wholesale contracts as needed to meet its retail load requirements or provide the most economic mix of resources on a variable cost basis. The Company has long-term power contracts with four hydroelectric projects on the mid-Columbia River, which provide approximately 456 MW of firm capacity. PGE also has firm contracts, ranging from one to thirty years, to purchase 848 MWa of power from other counterparties, including BPA, other Pacific Northwest utilities, and the Confederated Tribes of the Warm Springs Reservation of Oregon, and has a 30-year agreement for 27 MWa of wind capacity with an independent power producer which began in December 2005. In addition, PGE has an exchange contract with a summer-peaking California utility to help meet the Company's winter-peaking requirements, and an exchange contract with another Northwest utility to help meet the Company's summer-peaking requirements. These resources, along with short-term contracts, provide the Company with sufficient firm capacity to serve its peak loads. For further information, see "Power and Fuel Supply" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

Regional System Reliability

PGE relies on wholesale market purchases within the Western Electricity Coordinating Council (WECC) in conjunction with its base of generating resources to supply its resource needs and maintain system reliability. The WECC, a regional electric reliability organization, provides coordination for operating and planning a reliable and adequate electric power system for the western continental United States, Canada, and Mexico. It further supports competitive power markets, helps assure open and non-

discriminatory transmission access among members, provides a forum for resolving transmission access disputes, and provides an environment for coordinating the operating and planning activities of its members. The WECC area includes 14 western states, with peak loads that occur at different times of the year. Energy loads in California and the Southwest peak in the summer due to air conditioning use, while northern loads peak during winter heating months. According to WECC forecasts, its members, which serve a population of approximately 71 million, will have sufficient capacity margin to meet forecast demand and energy requirements through the year 2014, assuming the timely completion of planned new generation. The Northwest Power Pool (NWPP) area of the WECC, which contains significant hydro generation, is comprised of all or major portions of the states of Oregon, Washington, Idaho, Montana, Nevada, Utah, and Wyoming, and the Canadian provinces of British Columbia and Alberta. According to NWPP forecasts, hourly peak demand and annual energy requirements in the NWPP through 2014 are projected to grow at annual rates of 1.7% and 1.9%, respectively. The ability of the NWPP to meet peak demand is expected to be adequate for the next ten years, with reserve capability ranging from 31% to 40% of winter peak demand, as indicated in the above table.



PGE's peak load in 2005 was 3,608 MW, of which approximately 50% was met through short-term purchases. On December 31, 2005, PGE's total firm resource capacity, including short-term purchase agreements, was approximately 4,477 MW (net of short-term sales agreements of 1,132 MW).

The Pacific Northwest peak season continues to be in winter months, when home and business heating and lighting cause the highest demand. PGE's all-time peak of 4,073 MW occurred in December 1998.

Restoration of Salmon Runs

Populations of many salmon species in the Pacific Northwest have shown significant decline over the last several decades. A significant number of these species have been granted protection under the federal Endangered Species Act (ESA), which was initially enacted in 1966. The subsequent listing of various species of fish, wildlife, and plants as threatened or endangered species, has resulted in significant changes to federally-authorized activities, such as hydroelectric project operations. Long-term recovery plans for these species may include major operational changes to the region's hydroelectric projects. The biggest change thus far has been a modification in the timing of stored water releases from dams located in the upper parts of the Columbia River and Snake River basins.

PGE continues to evaluate the impact of current and potential ESA listings on the operation of its hydroelectric projects on the Deschutes, Sandy, Clackamas, and Willamette rivers. The Company's consultation with the National Oceanographic and Atmospheric Administration and the United States

Fish and Wildlife Service has identified opportunities for the protection of fish runs on those rivers where PGE operates. ESA consultations on PGE's Clackamas River projects, completed by the agencies in 2003, will be in effect until a new license is granted by the FERC. The Biological Opinion for the Bull Run Project (on the Sandy River), received in 2003, will cover the project's operations and decommissioning.

In 2005, PGE received Biological Opinions and Incidental Take Statements for the Company's Willamette River (Sullivan) and Deschutes River (Pelton Round Butte) projects associated with the issuance of new FERC licenses for these projects. The Biological Opinion and Incidental Take Statement, which provide authorization to licensees for the take of listed species consistent with terms and conditions identified in the consultation, are generally issued at the conclusion of the ESA consultation process associated with obtaining new or amended FERC hydropower licenses. There were no significant changes in the terms and conditions of the Company's new FERC licenses required to minimize take of ESA-protected species.

Fuel Supply

PGE acquires fuel supply contracts to support planned operation of thermal generating plants. Flexibility in contract terms allows for the most economic dispatch of PGE's thermal resources relative to the market price of wholesale power.

Coal

Boardman

PGE has negotiated purchase agreements that provide coal for Boardman's operating requirements through 2008. Available coal supplies are sufficient to meet future requirements of the plant. The coal, obtained from surface mining operations in Wyoming and subject to federal, state, and local regulations, is delivered by rail under two separate 10-year contracts, the terms of which began January 1, 2004. Coal purchases in 2005, totaling 2.3 million tons, contained approximately 0.3% of sulfur by weight. Utilizing electrostatic precipitators, the plant emitted less than the EPA-allowed limit of 1.2 pounds of sulfur dioxide per MMBtu.

Colstrip

Coal for Colstrip Units 3 and 4, located in southeastern Montana, is obtained from an adjacent mine under a contract that expires in 2009. The contract requires that the coal not exceed a maximum sulfur content of 1.5% by weight. In 2005, actual sulfur content for coal used at Colstrip ranged from approximately 0.74% to 0.78% by weight. Available coal supplies are sufficient to meet future requirements of the plant. Coal purchases for PGE's share of Colstrip Units 3 and 4 totaled 1.5 million tons in 2005. Utilizing wet scrubbers to minimize sulfur dioxide emissions, the plant operated in compliance with EPA's source-performance standards.

Natural Gas

PGE makes long-term, short-term, and spot market purchases to secure transportation capacity and short-term and spot market purchases to secure natural gas supplies sufficient to fuel plant operations. PGE re-markets natural gas and transportation capacity in excess of its needs.

PGE owns 79% of the Kelso-Beaver Pipeline, which directly connects its Beaver generating station to Northwest Pipeline, an interstate gas pipeline operating between British Columbia and New Mexico. PGE has been granted a blanket transportation certificate by the FERC that authorizes the Company to transport natural gas for others under a Part 284 blanket transportation certificate.

Currently, PGE transports gas on the Kelso-Beaver Pipeline for its own use under a firm transportation service agreement for all of its pipeline capacity, with capacity offered on an interruptible basis to the extent not utilized by the Company.

Beaver and Port Westward

Firm gas supplies for Beaver and Port Westward (scheduled to become operational in the first quarter of 2007) are purchased up to 24 months in advance, based on anticipated operation of the plants. PGE has access to 87,000 Dth/day of firm gas transportation capacity to serve the two plants. In addition, PGE has contractual access, through April 2017, to natural gas storage in Mist, Oregon, from which it can draw natural gas in the event that gas supplies are interrupted or if economic factors require its use. PGE believes that sufficient market supplies of gas are available to fully meet anticipated requirements of Beaver and Port Westward (for testing) in 2006.

Coyote Springs

The Coyote Springs generating station utilizes 41,000 Dth/day of firm transportation capacity on three pipeline systems accessing gas fields in Alberta, Canada. Firm gas supplies for Coyote Springs, based on anticipated operation of the plant, are typically purchased up to 24 months in advance. PGE believes that sufficient market supplies of gas are available to fully meet requirements of Coyote Springs in 2006.

Oil

Beaver

The Beaver generating station has the capability to operate at full capacity on No. 2 diesel fuel oil when it is economic or if the plant's natural gas supply is interrupted. To ensure the plant's continued operability under such circumstances, PGE had an approximate 12-day supply of oil at the plant site at December 31, 2005.

Coyote Springs

The Coyote Springs plant has the capability to operate on oil, although such capability has been deactivated in order to optimize natural gas operations. Should the plant's oil capability be restored, a fuel storage tank, capable of holding sufficient oil for 50 hours of operation, is available at the plant site.

Environmental Matters

PGE operates in a state recognized for environmental leadership. The Company's policy of environmental stewardship emphasizes minimizing both waste and environmental risk in its operations, along with promoting the wise use of energy.

Regulation

PGE's operations are subject to a wide range of environmental protection laws covering air and water quality, noise, waste disposal, and other environmental issues. The EPA regulates the proper use, transportation, cleanup and disposal of polychlorinated biphenyls (PCBs). State agencies or departments, which have direct jurisdiction over environmental matters, include the Environmental Quality Commission, the DEQ, the Oregon Department of Energy, and the EFSC. Environmental matters regulated by these agencies include the siting and operation of generating facilities and the accumulation, cleanup, and disposal of toxic and hazardous wastes.

Harborton

A 1997 investigation of a portion of the Willamette River known as the Portland Harbor, conducted by the EPA, revealed significant contamination of sediments within the harbor. Subsequently, the EPA has included Portland Harbor on the federal National Priority list pursuant to the federal Comprehensive Environmental Response, Compensation, and Liability Act (Superfund). In 2000, PGE, along with sixty-eight other companies on the Portland Harbor Initial General Notice List, received a "Notice of Potential Liability" with respect to the Portland Harbor Superfund Site. Sufficient information is currently not available to determine either the total cost of investigation and remediation of the Portland Harbor or the liability of Potentially Responsible Parties (PRPs), including PGE. Management believes that the Company's contribution to the sediment contamination, if any, would qualify it as a de minimis PRP.

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

Harbor Oil

Harbor Oil, Inc. (Harbor Oil), located in north Portland, was utilized by PGE to process used oil from the Company's power plants and electrical distribution system from at least 1990 until 2003. Harbor Oil is also utilized by other entities for the processing of used oil and other lubricants. A 2003 investigation conducted by the EPA revealed elevated levels of contaminants, including metals, pesticides, and PCBs on the Harbor Oil site. Subsequently, the EPA included Harbor Oil on the federal National Priority List as a federal Superfund site. In 2005, PGE received a Special Notice Letter for Remedial Investigation/Feasibility Study from the EPA, in which the Company was named as one of fourteen PRPs with respect to the Harbor Oil site. Sufficient information is currently not available to determine either the total cost of investigation and remediation of the Harbor Oil site or the liability of PRPs, including PGE.

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

Air Quality

PGE's operations, principally its fossil-fuel electric generation plants, are subject to the federal Clean Air Act (CAA) and other federal regulatory requirements. State governments also monitor and administer certain portions of the CAA and must set standards that are at least equal to federal standards; Oregon's air quality standards exceed federal standards. Primary pollutants addressed by the CAA that affect PGE are sulfur dioxide (SO₂), nitrogen oxides (NO_x), carbon monoxide (CO), and particulate matter. PGE manages its emissions by the use of low sulfur fuel, emission controls, emission monitoring, and combustion controls.

The SO₂ emissions allowances awarded under the CAA, along with expected future annual allowances, are sufficient to operate Boardman at a 60% to 67% capacity. PGE has acquired additional emissions allowances to operate the Boardman plant at forecasted capacity through mid-2008.

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

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

Regional Haze Study - In accordance with new federal regional haze rules, the DEQ is currently planning an assessment of emission sources pursuant to a Regional Haze Best Available Retrofit Technology (RH BART) process. Several other states are conducting a similar process. The DEQ has sent letters requesting information on twenty-two RH BART eligible sources in Oregon, including PGE's Boardman and Beaver generating plants. A demonstration analysis for identified sources, utilizing modeling techniques, is currently planned to begin during the first half of 2006. Those sources determined to cause, or contribute to, visibility impairment at protected areas in Oregon will be subject to an RH BART Determination. In January 2006, the Company volunteered to participate in a DEQ pilot project that will analyze information about air emissions from Boardman to determine their effect on visibility in the region, particularly in wilderness and scenic areas.

Mercury - In May 2005, the U.S. Environmental Protection Agency established the Clean Air Mercury Rule (CAMR), which regulates mercury emissions from the nation's coal-fired electric generating plants. The CAMR includes a federal "cap-and-trade" program (scheduled to begin in 2010), that establishes a cumulative total ("cap") of mercury emissions from all electric generating plants in the United States and assigns to each state a mercury emissions "budget." Individual states have the choice of adopting this model or establishing their own programs, which must be submitted for approval by November 2006. Oregon is considering whether to incorporate CAMR requirements into the state's program, which could impact the operations of Boardman.

It is not yet known what impacts state and federal regulations on air quality standards may have on future operations, operating costs, or generating capacity of PGE's thermal generating plants. For further information, see "Environmental Matters" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

Item 1A. Risk Factors

The following risk factors, in addition to other factors and matters discussed in this report, have been identified as those that could have a significant impact on PGE's financial and operating results. They should be considered when evaluating the Company.

PGE is subject to the risk that the OPUC will not allow sufficient recovery of the Company's costs and thus not provide a reasonable rate of return to shareholders.

The rates that the OPUC allows PGE to charge for its retail services is the major factor in determining the Company's operating income, financial position, liquidity, and credit ratings. The OPUC has the authority to disallow recovery of any costs that it considers excessive or imprudently incurred. The regulatory process does not provide assurance that PGE will be able to achieve earnings levels authorized.

The Company's March 2006 general rate case filing with the Commission includes separate components related to general (non-power) costs, the recovery of PGE's investment in the Port Westward generating plant (to be completed in the first quarter of 2007), and an adjustment to recover a projected increase in natural gas and purchased power prices in 2007. The filing also proposes a mechanism that addresses power cost volatility and provides for partial recovery of net variable power costs that exceed forecast. In a separate filing, the Company has also applied for a cost deferral and later rate recovery of a portion of incremental power costs caused by the forced repair outage of the Boardman plant. Should the OPUC grant substantially lower rate recovery than requested in these or other future proceedings, it could have a negative effect on results of operations and cash flows, which could impact the Company's credit ratings, potentially weaken its financial profile, and negatively impact liquidity.

Hydro generation comprises approximately 25% of PGE's total energy requirement. While the current RVM mechanism allows PGE to pass certain power cost variability to customers, the Company remains exposed to hydro risk, as there is currently no mechanism to share the risks and rewards of hydro variability with customers. Although the Company in 2004 filed with the OPUC for a hydro generation adjustment to recover high variable power costs caused by recent years' poor regional hydro conditions, this request was denied, and there is no assurance that the mechanism proposed in the Company's pending general rate case will receive sufficient regulatory support to adequately address this risk.

Unplanned outages at PGE's generating plants can increase the cost of power required to serve customers, as the cost of replacement power purchased in the wholesale market generally exceeds the Company's cost of generation.

The recent forced outage of the Boardman coal plant, a low-cost resource representing about one-fifth of PGE's generating capability, has had a significant negative impact on the Company's earnings due to high replacement power costs. The outage, which began in October 2005 and will continue into the second quarter of 2006, is projected to result in replacement power costs almost \$90 million greater than those estimated in setting rates for 2005 and 2006. As noted above, inability to recover such costs in future rates could have a significant negative impact on the Company's earnings.

The effects of weather on electricity usage can adversely affect financial results of operations.

Weather conditions can adversely affect PGE's revenues and costs and have a significant impact on the Company's financial and operating results. Temperatures outside the normal range can affect customer demand for electricity, with warmer-than-normal winters or cooler-than-normal summers

reducing power sales and revenues. Particularly for residential customers, weather conditions are the dominant cause of usage variations from normal seasonal patterns. Severe weather can also disrupt energy delivery and damage the Company's distribution system.

Rapid increases in load requirements resulting from unexpected adverse weather changes, particularly if coupled with transmission constraints, could adversely impact PGE's cost and ability to meet the energy needs of its customers. Conversely, rapid decreases in load requirements could result in the sale of excess energy at depressed market prices.

Weather conditions that reduce stream flows can adversely affect operating results.

PGE derives a significant portion of its power supply from its hydroelectric facilities and from those owned by certain public utility districts in the State of Washington and the City of Portland, with whom the Company has long-term power purchase contracts. Regional rainfall and snow pack levels significantly affect stream flows and the resulting amount of generation available from these facilities. Significant shortfalls in low-cost hydro production require increased generation from the Company's higher cost thermal plants and/or power purchases in the wholesale market to serve customers.

Wholesale energy markets are subject to forces that are often not predictable and which can result in price volatility, deterioration of liquidity, and general market disruption, adversely affecting PGE's costs and ability to manage its energy portfolio and procure required energy supply.

Wholesale electricity prices in the western United States are influenced primarily by factors related to supply and demand. These factors include the adequacy of generating capacity, scheduled and unscheduled outages of generating facilities, hydroelectric generation levels, prices and availability of fuel sources for generation, disruptions or constraints to transmission facilities, weather conditions, economic growth, and changes in technology. Volatility in wholesale energy markets can affect the availability and prices of purchased power and demand for energy sales. Changes in the creditworthiness of large wholesale customers can also affect PGE's variable power costs. Further, disruption in wholesale markets may result in a deterioration of market liquidity, increase the risk of counterparty default, affect the regulatory and legislative process in unpredictable ways, affect wholesale energy prices, and impair PGE's ability to manage its energy portfolio. Changes in wholesale energy prices also affect the market value of derivative instruments and unrealized gains and losses, as well as cash requirements to purchase electricity.

Market risk related to adverse fluctuations in the price of natural gas purchased as fuel for electricity generation can also significantly impact the Company. PGE purchases natural gas in the open market or pursuant to short-term or variable-priced contracts as part of its normal operating business. If market prices rise, especially during periods when the Company requires greater than expected volumes that must be purchased at market or short-term prices, PGE may incur significantly greater costs than projected. The Company may not be able to timely recover these increased costs through ratemaking.

PGE is exposed to risk related to performance of contractual obligations by its wholesale suppliers and customers.

As the Company relies on suppliers to deliver natural gas, coal and electricity, in accordance with short- and long-term contracts, failure to timely comply with existing contracts could disrupt PGE's ability to deliver electricity and require the Company to incur additional expenses to meet the needs of its customers. In addition, as these contractual agreements expire, PGE may be unable to continue to purchase natural gas, coal or electricity on terms equivalent to those of current agreements.

PGE is subject to political processes that may adversely affect its business.

These include public ownership initiatives whereby certain customer groups or governments attempt to acquire PGE facilities and equipment in the Company's allocated service territory through use of initiative petition and condemnation processes.

The City of Portland is currently investigating PGE's utility income taxes and prior years' energy trading practices. The Company has responded to the City's information requests regarding the income tax matters. However, PGE has declined to provide any additional data to the City. The City has indicated that it may pursue ratemaking for PGE's retail customers who reside within the city's boundaries. In addition, the City has filed court appeals of the OPUC's approval of the distribution of new PGE common stock, pursuant to Enron's Chapter 11 Plan, and the URP has filed an application with the OPUC for reconsideration of its approval. The ultimate outcome of these matters remains uncertain.

In 2003 and 2004, several public ownership initiatives were advanced whereby customer groups in four counties in which most of PGE's customers reside attempted to acquire Company facilities and form Public Utility Districts. Although such initiatives were rejected by the voters, there is no certainty that similar efforts will not again be attempted.

A new Oregon law related to income taxes could result in refunds to PGE's customers and adversely impact the Company's earnings.

A new law, referred to as Oregon Senate Bill 408, seeks to more closely match amounts collected for income taxes under the ratemaking process with income taxes paid to governmental entities by investor-owned utilities or their consolidated group. There is considerable uncertainty regarding several provisions of the law, with several issues subject to interpretation by the OPUC. Until the Commission issues permanent rules that implement the law, its impact on PGE and its customers will be difficult to assess. For the first quarter of 2006, PGE will continue to be a member of Enron's consolidated group for filing consolidated federal and state income tax returns. Based on the temporary rules, PGE anticipates that there will be material differences between taxes "authorized to be collected" and "taxes paid" in 2006, although the amount of those differences cannot be fully assessed until final rules are adopted. Accordingly, this could have a material adverse affect on the Company's earnings in 2006.

Regulations involving compliance with both new and existing environmental laws related to fish and wildlife could adversely affect PGE's results of operations.

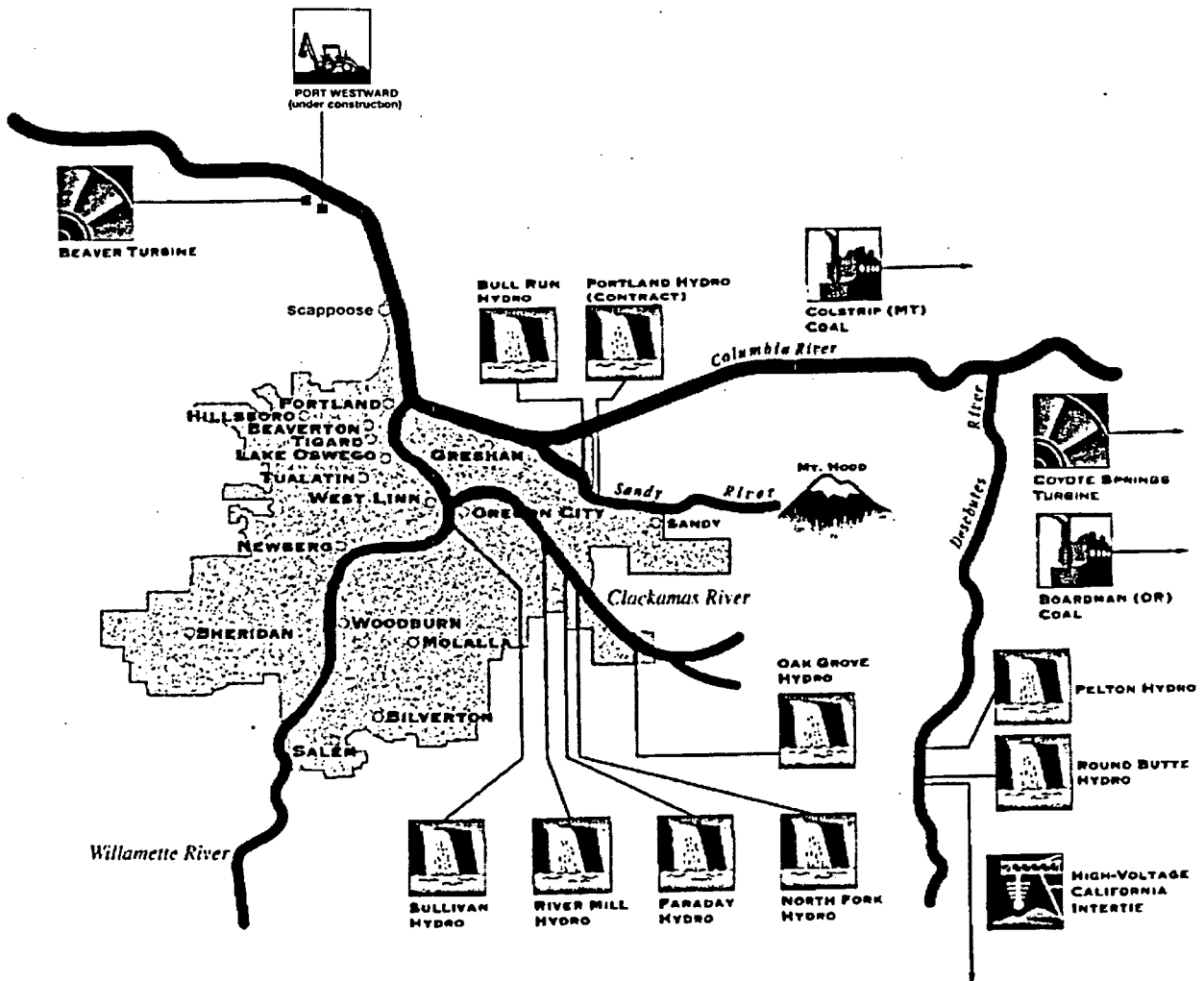
A significant portion of PGE's total energy requirement is comprised of generation from hydroelectric projects on the Columbia, Clackamas, Deschutes, Willamette, and Sandy rivers. Operations of these projects are subject to extensive regulation related to the protection of fish and wildlife. The listing of various species of salmon, wildlife, and plants as threatened or endangered species has resulted in significant changes to federally-authorized activities, including those of hydroelectric projects. Long-term salmon recovery plans may include further major operational changes to PGE and other hydro projects, and new interpretations of existing laws and regulations could be adopted or become applicable to such facilities, which could further increase required expenditures for salmon recovery and endangered species protection and reduce the amount of hydro generation available to meet the Company's energy requirements.

PGE is exposed to risks that impact the Company's ability to acquire those facilities required to meet the electricity demands of its customers.

Increases in both the number of customers and the demand for energy will require continued expansion and reinforcement of PGE's generation, transmission, and distribution systems. Construction of new generating facilities (including the Company's Port Westward project) may be affected by various factors, including unanticipated delays and cost increases, which could result in the disallowance of certain costs in the rate determination process. In addition, if construction projects are not completed according to specifications, reduced plant efficiency and higher operating costs could result. Equipment failure, the ability of generating plants to operate as intended, and other factors can result in plant performance that falls below expected levels. Cost and availability of fuel supplies, primarily natural gas and coal, can also significantly impact the cost and output of the Company's generating plants.

Item 2. Properties

PGE's principal plants and appurtenant generating facilities and storage reservoirs are situated on land owned by the Company in fee or land under the control of PGE pursuant to existing leases, federal or state licenses, easements, or other agreements. In some cases, meters and transformers are located on customer property. The Indenture securing PGE's First Mortgage Bonds constitutes a direct first mortgage lien on substantially all utility property and franchises, other than expressly excepted property. PGE's service territory and generating facilities are indicated on the map below:



The following are generating facilities owned by PGE:

			Net MW Capability At Dec. 31, 2005 (*)
Facility	Location	Fuel	
<u>Wholly Owned:</u>			
Faraday	Clackamas River	Hydro	46
North Fork	Clackamas River	Hydro	58
Oak Grove	Clackamas River	Hydro	44
River Mill	Clackamas River	Hydro	25
Bull Run	Sandy River	Hydro	22
Sullivan	Willamette River	Hydro	16
Beaver	Clatskanie, OR	Gas/Oil	545
Coyote Springs	Boardman, OR	Gas/Oil	243(d)
<u>Jointly Owned:</u>			
Boardman (a)	Boardman, OR	Coal	380
Colstrip 3 and 4 (b)	Colstrip, MT	Coal	296
Pelton (c)	Deschutes River	Hydro	73
Round Butte (c)	Deschutes River	Hydro	<u>225</u>
Total			<u>1,973</u>

(*) PGE ownership share.

(a) PGE operates Boardman and has a 65% ownership interest.

(b) PPL Montana, LLC operates Colstrip 3 and 4; PGE has a 20% ownership interest.

(c) PGE operates Pelton and Round Butte and has a 66.67% ownership interest.

(d) Decreased 2 MW in 2005 due to an assessment of turbine performance.

Hydro Relicensing

PGE holds licenses under the Federal Power Act and from the State of Oregon for its hydroelectric generating plants.

A new 50-year joint license for the Pelton Round Butte hydroelectric project, co-owned by PGE and the Confederated Tribes of the Warm Springs Reservation of Oregon, was issued by the FERC on June 21, 2005. The FERC also approved a settlement agreement, previously completed and signed by all participating parties, that includes provisions for fish passage over the project's three dams.

A new 30-year license for PGE's 16 MW Willamette River project was issued by the FERC on December 8, 2005. As part of the relicensing process, a settlement agreement was reached between the Company and participants in the process, including federal agencies responsible for salmon protection and ESA issues. The agreement includes several improvements to assist downstream passage of juvenile fish, reduce maintenance costs, and enhance production capacity through the replacement of most of the plant's turbines.

The license for the Clackamas River projects expires in 2006. PGE filed an application with the FERC in 2004 to relicense the projects and reached a settlement agreement with participating parties on March 2, 2006 that will be submitted to the FERC for review and approval. For further information, see "Hydro Relicensing" in Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations."

In October 2002, PGE entered into an agreement with state and federal agencies, conservation groups, and others regarding removal of the Company's 22 MW Bull Run hydroelectric project located in the Sandy River basin, including removal of the Marmot Dam in 2007 and the Little Sandy Dam in 2008. The agreement also provides for the protection of threatened fish species and the transfer of 1,500 acres of PGE-owned land to a nonprofit organization toward the creation of a 5,000-acre wildlife and public recreation area. The FERC issued a surrender order in 2004 and an annual operating license in early 2005 that allows PGE to operate the project until the removal of Little Sandy Dam. PGE has fully recovered its remaining plant investment and is recovering, over a ten-year period beginning October 2001, about \$16 million in estimated decommissioning costs.

Port Westward

The Port Westward Generating Plant, a 400 MW natural gas-fired facility located in Clatskanie, Oregon, is currently under construction. Construction of the plant began in February 2005 and is proceeding on schedule, with completion expected in the first quarter of 2007.

Transmission

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

Leased Properties

PGE leases its Portland headquarters complex. Coal handling facilities at the Boardman Plant, previously leased by the Company, were purchased in May 2005.

Item 3. Legal Proceedings

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

Following the closing of Trojan, PGE, in its 1993 general rate filing, sought OPUC approval to recover through rates future decommissioning costs and full recovery of, and a rate of return on, its Trojan investment. PGE's request was challenged and PGE requested from the OPUC a Declaratory Ruling (Docket DR 10) regarding recovery of the Trojan investment and decommissioning costs. In August 1993, the OPUC issued a Declaratory Ruling in PGE's favor, citing an opinion issued by the Oregon Department of Justice (Attorney General) that current law gave the OPUC authority to allow recovery of, and a return on, its Trojan investment and future decommissioning costs. The Declaratory Ruling was appealed to the Marion County Circuit Court, which upheld the OPUC in November 1994. The Citizens' Utility Board (CUB) appealed the decision to the Oregon Court of Appeals.

In PGE's 1995 general rate case (Docket UE 88), the OPUC issued an order (1995 Order) granting PGE full recovery of Trojan decommissioning costs and 87% of its remaining undepreciated investment in the plant. The Utility Reform Project (URP) filed an appeal of the 1995 Order to the Marion County Circuit Court, alleging that the OPUC lacked authority to allow PGE to recover Trojan costs through its rates. The CUB also filed an appeal to the Marion County Circuit Court challenging the portion of the 1995 Order that authorized PGE to recover a return on its remaining undepreciated investment in Trojan.

In April 1996, the Marion County Circuit Court issued a decision that contradicted the Court's November 1994 ruling. The 1996 decision found that the OPUC could not authorize PGE to collect a return on its undepreciated investment in Trojan. The 1996 decision was appealed to the Oregon Court of Appeals, where it was consolidated with the earlier appeal of the 1994 decision.

In June 1998, the Oregon Court of Appeals ruled that the OPUC does not have the authority to allow PGE to recover a rate of return on its undepreciated investment in Trojan, but upheld the OPUC's authority to allow PGE's recovery of its undepreciated investment in Trojan and its costs to decommission Trojan (1998 Decision). The court remanded the matter to the OPUC for reconsideration of its 1995 Order in light of the court's decision.

In August 1998, PGE filed a Petition for Review with the Oregon Supreme Court seeking review of that portion of the 1998 Decision relating to PGE's return on its undepreciated investment in Trojan. The URP filed a Petition for Review with the Oregon Supreme Court seeking review of that portion of the 1998 Decision relating to PGE's recovery of its undepreciated investment in Trojan.

In September 2000, PGE, CUB, and the OPUC Staff settled proceedings related to PGE's recovery of its investment in the Trojan plant (Settlement). The URP did not participate in the Settlement and filed a complaint and requested a hearing with the OPUC, challenging PGE's application for approval of the accounting and ratemaking elements of the Settlement.

In March 2002, after a full contested case hearing (Docket UM 989), the OPUC issued an order (Settlement Order) denying all of URP's challenges and approving PGE's application for the accounting and ratemaking elements of the Settlement. URP appealed the Settlement Order to the Marion County Circuit Court.

On November 19, 2002, the Oregon Supreme Court dismissed PGE's and URP's Petitions for Review of the 1998 Decision. As a result, the 1998 Decision stands and the remand of the 1995 Order to the OPUC became effective.

In regards to the URP's appeal of the March 2002 Settlement Order, on November 7, 2003, the Marion County Circuit Court issued an opinion remanding the case to the OPUC for action to reduce rates or order refunds. The opinion does not specify the amount or timeframe of any reductions or refunds. On February 9, 2004, PGE appealed this opinion to the Oregon Court of Appeals. The OPUC has also appealed.

On March 3, 2004, the OPUC re-opened Dockets DR 10, UE 88, and UM 989 and issued a notice of a consolidated procedural conference before an administrative law judge to determine what proceedings are necessary to comply with the Court of Appeals and Marion County Circuit Court orders remanding this matter to the OPUC.

On August 31, 2004, the administrative law judge issued an Order (Scoping Order) defining the scope of the proceedings necessary to comply with the Marion County Circuit Court orders remanding this matter to the OPUC. On October 18, 2004, the OPUC affirmed the Scoping Order. On December 20, 2004, the URP and Class Action Plaintiffs filed an application with the OPUC for reconsideration of the Scoping Order. On February 11, 2005, the OPUC denied reconsideration. On April 18, 2005, URP and Linda K. Williams filed a complaint against the OPUC in Marion County Circuit Court challenging the OPUC's affirmation of the Scoping Order. The OPUC filed a motion to dismiss the complaint, and on September 21, 2005, the Marion County Circuit Court granted the OPUC's motion. Hearings in the first phase of the OPUC proceeding have been held and a decision is pending.

Dreyer, Gearhart and Kafoury Bros., LLC v. Portland General Electric Company, Marion County Circuit Court Case No. 03C 10639; and Morgan v. Portland General Electric Company, Marion County Circuit Court Case No. 03C 10640.

On January 17, 2003, two class action suits were filed in Marion County Circuit Court against PGE on behalf of two classes of electric service customers. The Dreyer case seeks to represent current PGE customers that were customers during the period from April 1, 1995 to October 1, 2001 (Current Class) and the Morgan case seeks to represent PGE customers that were customers during the period from April 1, 1995 to October 1, 2001, but who are no longer customers (Former Class, together with the Current Class, the Class Action Plaintiffs). The suits seek damages of \$190 million for the Current Class and \$70 million for the Former Class, from the inclusion of a return on investment of Trojan in the rates PGE charges its customers.

On April 28, 2004, the plaintiffs filed a Motion for Partial Summary Judgment and on July 30, 2004, PGE also moved for Summary Judgment in its favor on all of Class Action Plaintiffs' claims. On December 14, 2004, the Judge granted the Plaintiffs' motion for Class Certification and Partial Summary Judgment and denied PGE's motion for Summary Judgment. PGE filed a proposed order certifying the issue for an interlocutory appeal. An order rejecting the proposed order was entered on February 1, 2005. On March 3, 2005, PGE filed a Petition for a Writ of Mandamus with the Oregon Supreme Court asking the Court to take jurisdiction and command the trial Judge to dismiss the complaints or to show cause why they should not be dismissed. On March 29, 2005, PGE filed a second Petition for an Alternative Writ of Mandamus with the Oregon Supreme Court seeking to overturn the Class Certification. On May 3, 2005, the Oregon Supreme Court granted both Petitions. Briefing and arguments have been completed and a decision is pending.

David Kafoury, an individual, and Kafoury Brothers, LLC, an Oregon Limited Liability Corporation, each as representative of class, etc. v. Portland General Electric Company, Multnomah County Circuit Court for the State of Oregon, Case No. 0501-00627

On January 18, 2005, David Kafoury and Kafoury Brothers, LLC filed a class action lawsuit in Multnomah County Circuit Court against PGE on behalf of all PGE customers who were billed on their electric bills and paid amounts for Multnomah County Business Income Taxes (MBIT) after 1996. The plaintiffs allege that during the period 1997 through the third quarter 2004, PGE collected in excess of \$6 million from its customers for MBIT that was never paid to Multnomah County. The charges were billed and collected under OPUC rules that allow utilities to collect taxes imposed by the county. As a member of Enron's consolidated income tax return, PGE paid the tax it collected to Enron. The plaintiffs seek a judgment against PGE for restitution of MBIT collected from customers. Plaintiffs also seek interest, recoverable costs, and reasonable attorney fees. The Plaintiffs filed an amended complaint on February 25, 2005, adding claims for fraud, unjust enrichment, conversion, statutory violations, and seeking punitive damages. On February 24, 2005, PGE requested a declaratory ruling from the OPUC on this matter. On May 17, 2005, the OPUC agreed to consider the question posed by PGE; whether the OPUC rules authorized PGE collections of the MBIT and, if not, whether refunds are controlled by the OPUC three-year limitation for billing adjustments.

On March 24, 2005, PGE filed in the Circuit Court a motion to abate or in the alternative to dismiss. On May 23, 2005, the Circuit Court granted PGE's motion for a stay for all purposes until October 15, 2005, with the opportunity to renew if the OPUC has not issued its declaratory ruling.

On October 5, 2005, the OPUC issued an order in the declaratory ruling docket in which it determined that the rules in question required only that PGE allocate this tax to Multnomah County customers and did not require that PGE calculate it in any particular way. PGE notified the Court of the Company's intent to voluntarily refund MCBIT (plus interest) to customers and filed motions requesting the Court's guidance regarding the number of years for which refunds should be made.

On December 28, 2005, the parties agreed to a settlement by which PGE will make refunds and payments totaling \$10 million, inclusive of interest and plaintiffs' attorney fees, costs, and expenses as approved by the Court's final order. Distribution to customers is limited to amounts collected during the period 1999 through 2005. The settlement is subject to final approval by the Multnomah County Circuit Court following a hearing currently scheduled for late July 2006.

Port of Seattle vs. Avista Corporation, Avista Energy, Inc., El Paso Electric Company, Idacorp, Inc., Idaho Power Co., PacifiCorp, Portland General Electric Company, Powerex Corporation, PPL Montana, LLC, Puget Energy, Inc., Puget Sound Energy, Inc., Scottish Power, PLC, Sempra Energy, Sempra Energy Resources, Sempra Energy Trading Corp., Transalta Corporation, Transalta Energy Marketing, Inc. United States District Court for the Western District of Washington, Case No. CV03-1170P.

On May 21, 2003, the Port of Seattle, Washington (Port) filed a complaint in the U.S. District Court for the Western District of Washington against PGE and sixteen other companies (Defendants) alleging violation of both the Sherman Act and the Racketeer Influenced and Corrupt Organization Act, fraud, and, with respect to Puget Energy, Inc. and Puget Sound Energy, Inc., breach of contract. The complaint alleges that the price of electric energy purchased by the Port between November 1997 and June 2001 under a contract with Puget Sound Energy, Inc. was unlawfully fixed and artificially increased through various actions alleged to have been undertaken in the Pacific Northwest power markets among Defendants and Enron Corp., Enron Energy Services, Inc., Enron North America Corp., Enron Power Marketing, Inc., and others. The complaint alleges actual damages of \$30.5 million suffered by the Port and seeks recovery of that amount, plus punitive damages and reasonable attorney fees. On December 4, 2003, this case was transferred to the Southern District of California.

On May 12, 2004, the Court entered an order dismissing the case based on federal preemption of state law claims, the exclusive jurisdiction of the FERC over electricity markets, and the "filed rate doctrine" that holds that rates approved by a governing regulatory agency are reasonable and unassailable in judicial proceedings brought by ratepayers. The plaintiffs in this case have appealed the Court's decision to the United States Ninth Circuit Court of Appeals. A decision is pending.

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

On June 30, 2003, the Montana Attorney General filed a complaint in Montana state court against PGE and numerous named and unnamed generators, suppliers, traders, and marketers of electricity and natural gas in Montana. The Complaint alleges unfair and deceptive trade practices in violation of the Montana Unfair Trade and Practices and Consumer Protection Act, deception, fraud and intentional infliction of harm arising from various actions alleged to have been undertaken in the western wholesale electricity and natural gas markets during 2000 and 2001. The relief sought includes injunctive relief to prohibit the unlawful practices alleged, treble damages, general damages, interest, and attorney fees. No monetary amount is specified. The case was removed to U.S. District Court of Montana in July 2003 then remanded back to Montana state court in November 2003. The case is pending in state court while investigation is underway by the Montana Public Service Commission (MPSC) in Docket No. D2004.2.21. PGE is not included in the MPSC proceeding and has not yet been served in the state court case.

Wah Chang, a division of TDY Industries, Inc. v. Avista Corporation, Avista Energy, Inc., Avista Power, LLC, Dynegy Power Marketing, Inc., El Paso Electric Company, IDACORP, Inc., Idaho Power Company, IDACORP Energy L.P., Portland General Electric Company, Powerex Corporation, Puget Energy, Inc., Puget Sound Energy, Inc., Semptra Energy, Semptra Energy Resources, Semptra Energy Trading Corp., Williams Power Company, Inc., United States District Court for the District of Oregon, Case No. 04-CV-00619-AS.

On May 5, 2004, Wah Chang, a division of TDY Industries (Wah Chang), filed a complaint in the U.S. District Court for the District of Oregon against PGE and fifteen other companies (Defendants) alleging that practices among the Defendants and/or Enron and others involving the generation, purchase, sale and transmission of electric energy, beginning in 1998 and continuing through 2001, were designed to communicate false or misleading information to participants in the energy market with the purpose of causing a shortage or appearance of a shortage in the generation of electricity, the appearance of congestion in the transmission of electricity, illegally raising the price of electricity, and fraudulently concealing illegal activities, all in violation of Federal and state antitrust statutes, the Racketeer Influenced and Corrupt Organization Act and for wrongful interference with their purchase contracts with PacifiCorp. No specific facts as to PGE's activities are alleged. Wah Chang seeks compensatory (\$30 million) and treble damages.

On February 11, 2005, the Court entered an order dismissing the case based on federal preemption of state law claims, the exclusive jurisdiction of the FERC over electricity markets, and the "filed rate doctrine" that holds that rates approved by a governing regulatory agency are reasonable and unassailable in judicial proceedings brought by ratepayers. On March 10, 2005, Wah Chang filed a notice of appeal in the Ninth Circuit Court of Appeals.

City of Tacoma, Department of Public Utilities, Dreyer, Light division v. American Electric Power Service Corporation, Quila Holdings, LLC, Aquila Power Corporation, Arizona Public Service Company, Automated Power Exchange, Inc., Avista Corporation, et. al., United States District Court for the Western District of Washington, Case No. C07-5325 RBL.

On June 7, 2004, the City of Tacoma, Washington filed a complaint in the U.S. District Court for the Western District of Washington against PGE and fifty-five other companies (Defendants) alleging that sometime during or before May 2000 and continuing through at least the end of 2001, the Defendants, acting in concert with some or all of thirty non-party co-conspirators, engaged in a pattern of activities involving the generation, purchase, sale and transmission of electric energy that violated the Sherman Antitrust Act and damaged the City of Tacoma in an amount estimated to exceed \$175 million. No specific facts as to PGE's activities are alleged. The City of Tacoma seeks recovery of three times the amount of actual damages proved at trial. PGE contends this lawsuit is precluded by the 2003 settlement of FERC Docket No. EL02-114, under which PGE paid Tacoma \$1.1 million and for which PGE obtained a complete release from all claims related to electricity prices during 2000-2001 from the California Parties, the City of Tacoma, and others.

On February 11, 2005, the Court entered an order dismissing the case based on federal preemption of state law claims, the exclusive jurisdiction of the FERC over electricity markets, and the "filed rate doctrine" that holds that rates approved by a governing regulatory agency are reasonable and unassailable in judicial proceedings brought by ratepayers.

On March 10, 2005, a notice of appeal was filed in the Ninth Circuit Court of Appeals.

Ankeny, et al v. Northwestern Energy, L.L.C.; PPL Montana, LLC; Puget Sound Energy, Inc.; Avista Energy, Inc.; Pacific Energy GP, Inc.; Pacific Energy Group LLC.; Touch America Holdings, Inc.; PacifiCorp; Bechtel Construction Operations Incorporated; Western Energy Company; Portland General Electric Company; and John Does 1-20, Montana Second Judicial District, Rosebud County, Case No. DV 03-109

On May 5, 2003, residents of Colstrip, Montana, unions and businesses filed a suit against PGE and the other owners, designers and operators of the Colstrip coal-fired electric generation plants (Colstrip Project) in Montana alleging that holding and settling ponds at the Colstrip Project have leaked and contaminated groundwater. The plaintiffs allege nuisance, trespass, unjust enrichment, fraud, and negligence, and seek a declaratory judgment of nuisance and trespass, an order that the nuisance be abated, and an unspecified amount for damages, disgorgement of profits, and punitive damages.

On July 18, 2005, an Amended Complaint was filed, which modifies the named plaintiffs and provides further clarification of the underlying claims. Trial is scheduled to start in early 2007.

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

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

On May 28, 2003, PGE filed a motion for summary judgment. On August 14, 2003, the Court granted PGE's motion for summary judgment finding that the grievances are not subject to arbitration. A final judgment was entered on October 6, 2003. On October 22, 2003, the IBEW filed an appeal to the Oregon Court of Appeals.

Both the U.S. District Court and the Bankruptcy Court approved the settlement of the class action litigation styled In re Enron Corp. Securities Derivative & "ERISA" Litigation, Pamela M. Tittle, et al, v. Enron Corp., et al, Civil Action No. H-01-3913, U.S. District Court for the Southern District of Texas, Houston Division (Tittle Action) and on September 13, 2005, the U.S. District Court entered a Bar Order in the Tittle Action, which specifically bars all claims arising out of that case, including the IBEW grievance proceeding. On October 18, 2005, at the request of the Oregon Court of Appeals, PGE filed a response memorandum in which PGE argued that the Bar Order makes the grievance moot. A decision is pending.

Portland General Electric Co. v. City of Glendale (California), United States District Court for the District of Oregon, Case No. 051321

On August 25, 2005, the Company filed a complaint in the U.S. District Court for the District of Oregon against the City of Glendale (Glendale) seeking a declaratory ruling with respect to a long-term power sale and exchange agreement between the Company and Glendale entered into in 1988 which expires in 2012. Under the agreement, Glendale purchases firm system capacity up to 20 MW plus associated energy costs as scheduled by Glendale. Glendale has requested refunds, asserting that its price is capped so the Company cannot charge a price greater than the most expensive generation resource in the Company's inventory. Glendale has also asserted that the shutdown of Trojan was the equivalent of a sale of a Company resource that triggered a duty under the agreement to renegotiate price terms "to avoid a significant distortion in the Parties' bargain." The Company's complaint seeks a declaratory ruling that the Company does not owe Glendale any amounts under the agreement and that the decommissioning of Trojan does not require the Company to renegotiate payments due to it from Glendale. On October 18, 2005, Glendale filed a Complaint with the FERC requesting the FERC to direct the Company to adjust the price and provide refunds of approximately \$23.3 million plus interest. The Court granted a stipulation filed by PGE and Glendale to stay the Court proceedings pending a decision by the FERC on its jurisdiction. On December 19, 2005, the FERC dismissed Glendale's complaint. Glendale has filed a request for a rehearing with the FERC.

City of Portland v. Oregon Public Utility Commission, Portland General Electric Company, Stephen Forbes Cooper, LLC, Citizens' Utility Board of Oregon, Industrial Customers of Northwest Utilities, Community Action Directors of Oregon, and Oregon Energy Coordinators Association, Court of Appeals of the State of Oregon Case No. A131268GE and Marion County Oregon Circuit Court Case No. 06C11248.

On February 10, 2006, the City of Portland ("City") appealed the December 14, 2005 order of the OPUC that authorized the issuance of new PGE common stock (OPUC Order). Appeals were filed both in the Marion County Circuit Court and the Oregon Court of Appeals. The City filed its appeals in both courts due to the jurisdictional uncertainty created by new Oregon law governing appeals of OPUC decisions. In its appeal to the Circuit Court, the City alleges the OPUC made its decision on an inadequate record, failed to enter adequate findings in support of its decision, abused the discretion granted it by Oregon law and based its decision on a statute that constituted an unlawful delegation from the Oregon Legislature. For relief, the City requests the OPUC Order be modified, reversed or remanded. In the Court of Appeals filing, the City alleges it is an aggrieved party and asks for judicial review without further details. On February 23, 2006, the OPUC filed a Motion to Hold Case in Abeyance with the Marion County Circuit Court in order to seek summary determination from the Court of Appeals regarding the proper court to hear the City's appeal. The City and other defendants to the action, including PGE, did not oppose the motion. The Circuit Court has not ruled on this motion.

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

None.

Part II

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

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

<u>Quarter</u>	<u>2005</u>	<u>2004</u>
1	\$ -	\$ -
2	-	-
3	150	-
4	-	-

PGE is restricted, without prior OPUC approval, from making dividend distributions to Enron that would reduce PGE's common equity capital below 48% of total capitalization (excluding short-term borrowings).

On December 14, 2005, the OPUC issued an order approving the issuance of new PGE common stock and the corresponding cancellation of the existing stock owned by Enron, in accordance with Enron's Chapter 11 Plan. The order includes a stipulation containing several conditions, including a requirement that, after issuance of the new stock, PGE cannot pay a dividend that would cause the common equity capital percentage to fall below 48% (plus \$40 million) without Commission approval. PGE has agreed to maintain the additional \$40 million of common equity pending the outcome of its next general rate case to assure the Company's financial capacity to absorb any adjustment(s) in its revenue requirement related to its ownership by Enron. The requirement is reduced to 45% when the Disputed Claims Reserve (DCR) holds between 20% and 40% of the issued and outstanding common stock of PGE, with no minimum common equity capital percentage requirement when the DCR holds less than 20% of the issued and outstanding common stock of PGE. Other conditions include a requirement that the OPUC be notified (simultaneously with the public) of any dividend declared by PGE's Board of Directors and that, before the issuance of new common stock, PGE cannot make a dividend distribution to Enron unless PGE has a rating on its senior secured debt of not lower than BBB+ from Standard & Poor's.

For further information, see Note 4, Common and Preferred Stock, in the Notes to Financial Statements.

Item 6. Selected Financial Data

	For the Years Ended December 31				
	<u>2005</u>	<u>2004</u>	<u>2003</u>	<u>2002</u>	<u>2001</u>
			(In Millions)		
Operating Revenues (a)	\$1,446	\$1,454	\$1,752	\$1,855	\$2,420
Net Operating Income	126	150	124	135	134
Net Income (b)	64	92	60	66	34
Total Assets (c)	3,638	3,403	3,372	3,455	3,622
Long-Term Debt (d)	890	922	983	1,046	972

- (a) Operating Revenues for 2003 through 2005 reflect the October 1, 2003 adoption of EITF 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, and 'Not Held for Trading Purposes'." EITF 03-11 requires that realized gains and losses associated with non-trading derivative activities that are not physically settled be reported on a net basis. Prior to October 1, 2003, such settlements were recorded on a gross basis in both Operating Revenues and Purchased Power and Fuel expense. Amounts for periods prior to October 1, 2003 were not reclassified. Accordingly, Operating Revenues for these periods are not fully comparable to the years 2003 through 2005 and do not reflect PGE's current reporting. For further information, see Note 1, Summary of Significant Accounting Policies, in the Notes to Financial Statements.
- (b) Net Income for 2003 was restated. For further information, see Note 16, Restatement of Prior Period Financial Statements, in the Notes to Financial Statements.
- (c) Amounts for 2001 and 2002 were reclassified from those reported in the respective Form 10-Ks to reflect the transfer of accumulated asset retirement removal costs from Accumulated Depreciation to Other liabilities, in accordance with SFAS No. 143, Asset Retirement Obligations, and SFAS No. 71, Accounting for the Effects of Certain Types of Regulation.
- (d) Includes long-term debt and preferred stock subject to mandatory redemption requirements.

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

Overview

PGE is a single integrated electric utility engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the State of Oregon, as well as the wholesale sale of electricity and natural gas throughout the western states. PGE's mission is to be a company that customers depend on to provide electric service in a safe and reliable manner with excellent customer service at a reasonable price. The OPUC establishes tariffs and retail revenue requirements based upon the cost to serve retail customers and a fair return on investment, using a forecasted test year and an original cost rate base. Wholesale power and transmission prices are regulated by the FERC.

While Oregon's electricity restructuring law provides for both direct access to competing energy suppliers and for market price options, the Company remains obligated to provide service to all of its retail customers, the large majority of which buy electricity at prices determined by the cost of service. Subject to regulatory review and timing, PGE expects the OPUC to recognize all prudently-incurred costs in setting prices, although there can be no assurance that the Company will have an opportunity to fully recover its costs through prices set in the regulatory process. While customer prices applicable to projected power costs are currently adjusted on an annual basis, prices applicable to non-power costs are adjusted only in a general rate proceeding. As electricity prices are fixed during the year, fluctuations in energy sales, hydro output, plant availability, and power and fuel prices can significantly impact the Company's earnings.

Future Ownership of PGE - Enron and PGE are moving forward to distribute new PGE common stock to the Debtors' creditors holding allowed claims in accordance with the Chapter 11 Plan, with applications approved by all required regulatory agencies. The issuance of new PGE common stock is currently expected to take place on or about April 3, 2006, and PGE has filed an application to list the stock on the New York Stock Exchange. Following the issuance, PGE will no longer be a subsidiary of Enron. Enron has also indicated that it will continue to consider credible offers to purchase PGE's common stock until the new common stock is issued. The transition from Enron's ownership of PGE has continued, with control of employee benefit and retirement savings plans returned to the Company at the beginning of 2005. The Company's Board of Directors has been expanded, with six new members appointed in January 2006. For further information, see "Future Ownership of PGE" in "Financial and Operating Outlook" of this Item 7.

Customers - PGE continues its focus on customer service and recognizes the importance of reliability, restoration response, safety, and reasonable rates in maintaining overall customer satisfaction. The Company meets regulatory standards for safety and service quality related to outage frequency and duration.

Like most utilities, PGE's business is affected by the general economy and by population growth in its service territory. The Company continues to experience customer growth, adding approximately 55,000 retail customers in the last five years (including 13,000 in 2005), and now serves over 780,000 retail customers as the largest supplier of electricity in the state. Although slowing somewhat in the last half of 2005, the state's economy has generally continued to rebound from the 2001-2003 period, adding over 100,000 jobs (including over 16,000 in manufacturing) during the last two years, resulting in annual average payroll gains of 2% in 2004 and 3.4% in 2005. Non-farm employment (seasonally adjusted) in December 2005 exceeded the previous peak, with the unemployment rate falling from a

high of 8.5% in July 2003 to 7.0% at year-end 2004 to 5.7% at the end of 2005. Continued high energy prices and rising short-term interest rates, however, could affect future growth of both the national and state economy.

PGE seeks to exert a positive influence on the long-term economic strength of the Company's service area and continues to play an active role in supporting growth and business development in the region. The Company works with local, state and regional agencies to assist existing businesses with operating and expansion plans and to provide assistance to businesses considering new activity in Oregon. PGE has played a key leadership role in assisting communities in the Company's service area with economic development strategies, including those initiated at the recent Oregon Business Plan Summit, and has been instrumental in the growth of key industry clusters representing a large number of metals and transportation equipment businesses in the state.

Power Supply - PGE manages its power supply to secure reasonably priced power for customers by effectively using the Company's generating assets and marketing and operational expertise. PGE can meet approximately 75% of its peak load requirement with output from its generating plants and long-term hydro contracts, with the remaining 25% met with short-term and other long-term power purchases in the wholesale market. The portion of retail load met with power purchases can increase if it becomes more economic to purchase electricity than to generate it with the Company's thermal resources.

PGE's twelve diversified generating plants (40% gas/oil, 34% coal, and 26% hydro) have both base-load and peaking capabilities, with fuel for thermal plants supplied under short-term agreements and spot-market purchases, allowing the Company to dispatch its thermal resources based upon the market price of wholesale power relative to the market price of natural gas or coal. Wholesale energy market prices have continued to increase over the last year, reflecting higher natural gas prices and below-normal regional hydro conditions. PGE remains active in wholesale energy markets in order to meet retail load requirements. The Company utilizes wholesale electricity and fuel purchases, as well as its generating plants, to maintain a balanced position.

Regional water conditions in 2005 were below both average and 2004 levels, resulting in reduced generation from PGE's hydro projects. Output from mid-Columbia River hydro projects, with which PGE has long-term power purchase contracts, was slightly higher in 2005. Regional hydro conditions, including those on both the Clackamas and Deschutes river systems where the Company's facilities are located, are currently projected to be near normal for 2006.

Renewable generation purchased from a 27 MWa wind farm became available on December 1, 2005, with the 50-turbine project generating enough electricity to power 18,000 homes. This is PGE's largest renewable power purchase to date and marks the first major step toward meeting the Company's renewable power supply goal of 200 MW. The Company continues to implement its Integrated Resource Plan to meet the future electricity needs of customers, with construction of the 400 MW natural gas-fired Port Westward plant proceeding on schedule, with completion expected in the first quarter of 2007.

In June 2005, the FERC approved a 50-year joint license application for the Pelton Round Butte hydro project and in December 2005 a new 30-year license was issued for PGE's 16 MW Willamette River project. A settlement agreement related to the previously filed license application for the Company's four Clackamas River projects has been signed by participating parties and will be submitted to the FERC for review and approval. These facilities continue to provide a low-cost source of power for PGE customers.

Operations - In October 2005, following the detection of vibrations in Boardman's steam turbine rotor, the plant was taken out of service, with the rotor removed in mid-November and shipped to an east coast facility for repair. During the process of returning the plant to operation in early February 2006, the generator rotor was damaged and subsequently removed for further examination and repairs. It is currently estimated that the plant will be operational by late April 2006. Replacement power costs of approximately \$41 million were incurred during the fourth quarter of 2005, with first quarter 2006 costs estimated at \$45 million. Estimated replacement power costs for April 2006 are expected to range from \$200,000 to \$300,000 per day. During the plant's extended outage, annual maintenance requirements, originally scheduled for the second quarter of 2006, were completed.

Aside from the extended repair outage at Boardman, PGE's generating plants continued to operate well in 2005, with total output approximating that of 2004. Required annual maintenance at the Company's thermal facilities was successfully completed by the end of the year's third quarter.

PGE utilized its mix of generating assets and activities in the wholesale marketplace to meet the 2005 electricity needs of its customers and offset the adverse effects of the year's moderate drought conditions and the extended repair outage at Boardman. Increased retail energy deliveries (including those to commercial and industrial customers that purchase their energy from ESSs) reflect continued customer growth and an improved economy, with gains in all major customer sectors. Weather adjusted retail energy deliveries to PGE and ESS customers are expected to increase by approximately 2% in 2006.

PGE continues to invest in its transmission and distribution systems and in additions and upgrades to its generating facilities. Decommissioning of the closed Trojan nuclear plant is proceeding, and in May 2005, following the completion of radiological decommissioning and approval by the NRC, the plant's facility operating license was terminated. PGE has accelerated the planned demolition of major non-radiological structures at Trojan, including the cooling tower and those buildings that once housed the plant's turbine, reactor, and spent fuel pool.

2005 Financial Performance - Due largely to Boardman's extended repair outage during most of the fourth quarter of 2005, PGE's earnings declined about 30% from 2004. The unplanned outage required that PGE replace its portion of the plant's generation with higher-priced wholesale power purchases and increased natural gas-fired generation, resulting in a significant decrease in PGE's net operating income and a net loss for the fourth quarter of 2005. Earnings for 2005 were also negatively affected by higher operating expenses and by PGE's decision, as part of a settlement, to make refunds and payments totaling \$10 million to Multnomah County customers for business income taxes collected in prior years.

Despite the challenges of poor hydro conditions in 2005, the lack of any power cost adjustment mechanism, and the extended Boardman outage, PGE continues to maintain adequate liquidity and stable operating cash flow. The Company secured a new \$400 million five-year credit facility in May 2005 and continues to effectively invest in its systems, acquire and plan for new power supply resources, and maintain operational efficiency.

Regulatory Matters - The "Resource Valuation Mechanism" (RVM) process, by which retail prices are adjusted annually with changes in projected power costs, has enabled PGE to adjust customer prices on a more timely basis to reflect the expected variable cost of power. This process resulted in moderate average rate increases for 2005 and 2006. A previously-filed Hydro Generation Adjustment tariff and deferral application, which would have allowed for the deferral and future rate recovery of a portion of power cost changes caused by variations in hydro conditions, was denied by the OPUC.

PGE has also filed an application with the OPUC seeking deferral, for future ratemaking treatment, of excess replacement power costs related to Boardman's outage for repairs to the plant's steam turbine rotor, which ended on February 5, 2006. PGE has determined, however, that it will not file an application to defer such costs related to the outage resulting from damage to the generator rotor, which began February 6, 2006. For further information, see "Boardman Coal Plant - Extended Outage" in "Financial and Operating Outlook" of this Item 7.

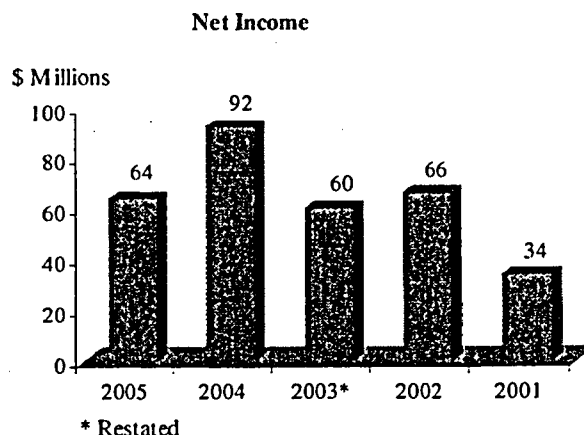
A new law, Oregon Senate Bill 408, seeks to more closely match amounts collected for income taxes under the ratemaking process with income taxes paid to governmental entities by investor-owned utilities or their consolidated group. PGE is participating in the Commission's comprehensive rule-making process to implement the new law. The Company has filed a report, as required by the new law, on taxes "collected" and "paid" (as defined under temporary rules and Senate Bill 408) for the years 2002-2004. Under the law, however, the first rate adjustment applies only to taxes paid and amounts collected from customers beginning in 2006. There is considerable uncertainty regarding several provisions of the law and the Company continues to evaluate its potential effects.

In order to align PGE's rate structure to sufficiently cover its operating costs, the Company filed a general rate case in March 2006 for consideration by the OPUC. Major components of the filing include power costs and the recovery of PGE's investment in Port Westward. The Commission's review is estimated to take from nine to ten months, with rate adjustments expected to become effective in early 2007.

Results of Operations

2005 Compared to 2004

PGE's net income in 2005 was \$64 million compared to \$92 million in 2004. The decrease was due primarily to reduced margins on energy sales, caused by replacement power costs for the extended, unplanned outage at the Boardman coal plant for repair of the plant's turbine rotor. In addition, results for 2005 were adversely affected by higher administrative and general expenses (including the settlement of certain asserted claims), a reserve for the refund to customers of previously collected local income taxes, and higher expenses related to preventive maintenance of the Company's distribution facilities.

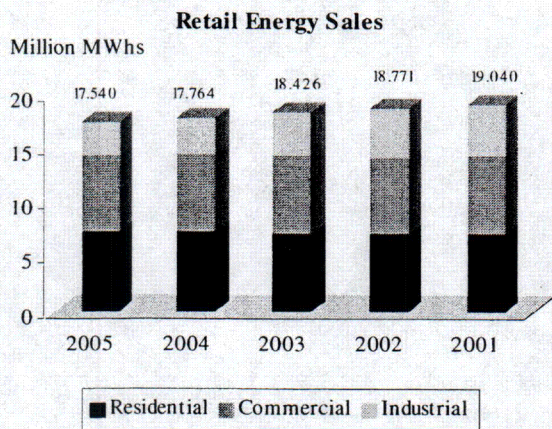


The following table summarizes Operating Revenues and Energy Sold and Delivered for 2005 and 2004:

	2005	2004	Increase/ (Decrease)
Operating Revenues (In Millions)			
Retail Operating Revenues:			
Retail	\$ 1,305	\$ 1,311	\$ (6)
Direct Access Customer Revenues	-	7	(7)
Total Retail Revenues	1,305	1,318	(13)
Wholesale (Non-Trading)	116	107	9
Other Operating Revenues:			
Trading Activities - net	-	1	(1)
Other	25	28	(3)
Total Operating Revenues	\$ 1,446	\$ 1,454	\$ (8)
Energy Sold and Delivered (In Thousands of MWhs)			
Retail Energy Deliveries			
Retail Energy Sales	17,540	17,764	(224)
Energy Delivered to Direct Access Customers	1,214	776	438
Total Retail Energy Deliveries	18,754	18,540	214
Wholesale (Non-Trading)	2,094	2,539	(445)
Trading Activities	815	9,699	(8,884)
Total Energy Sold and Delivered	21,663	30,778	(9,115)

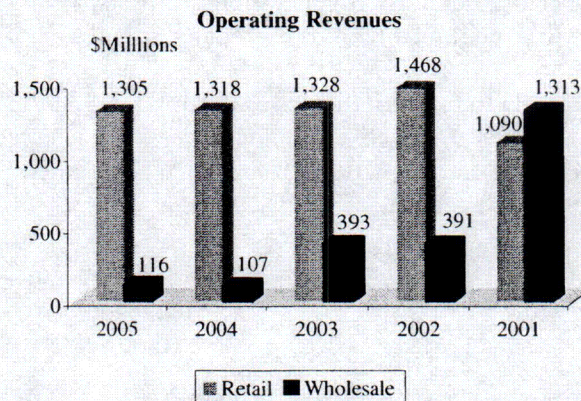
Total Retail Revenues decreased about 1% from 2004. A decrease in energy sales and a \$23 million reduction in amounts recovered from customers related to power cost adjustment mechanisms in effect in 2001 and 2002 (fully offset within Purchased Power and Fuel expense) were partially offset by a 1.4% average rate increase for 2005. (For further information, see "Resource Valuation Mechanism" in "Financial and Operating Outlook" of this Item

7). The decrease in Direct Access Customer Revenues, consisting of service charges for electricity delivered to customers who purchase their energy requirements from ESSs, was attributable to "transition adjustment" credits, reflecting the difference between the cost and market value of PGE's power supply portfolio, as provided by Oregon's electricity restructuring law. Total Retail Energy Sales decreased 1%, with declines in both commercial and industrial usage partially offset by increased residential use resulting from colder weather in the fourth quarter of 2005 and an approximate 11,000 increase in customers served. Declines in commercial and industrial energy sales



of 2.5% and 3.1%, respectively, were largely related to customers who chose to purchase their energy requirements from ESSs beginning in 2005. PGE continues to deliver energy to these customers, with about one-third of the increase in Total Retail Energy Deliveries in 2005 attributable to a single large industrial customer.

Wholesale revenues increased by about 8% in 2005 due primarily to a 32% increase in average price, driven largely by higher natural gas prices. This was partially offset by an approximate 18% reduction in wholesale electricity sales resulting from reduced market activity.



The decrease in Other Operating Revenues from last year was caused primarily by reduced margins on the sale of natural gas in excess of plant requirements.

Purchased Power and Fuel expense for 2005 increased \$4 million (1%) from 2004. An 11% increase in PGE's average variable power cost was largely offset by both a reduction in total system load and a \$24 million decrease related to the amortization of costs deferred under power cost adjustment mechanisms in effect during 2001 and 2002, which were later recovered from customers (fully offset within Retail revenues). The increase in average variable power cost was caused primarily by approximately \$41 million of incremental power costs incurred to replace coal-fired generation at Boardman, which was taken out of service in mid-October 2005 for removal and repair of the plant's turbine rotor. Lower hydro production in 2005 (due to low stream flows) also contributed to the year's higher average variable power cost. Such cost increases were partially offset by higher unrealized gains from derivative instruments. Company generation decreased about 4% from 2004,

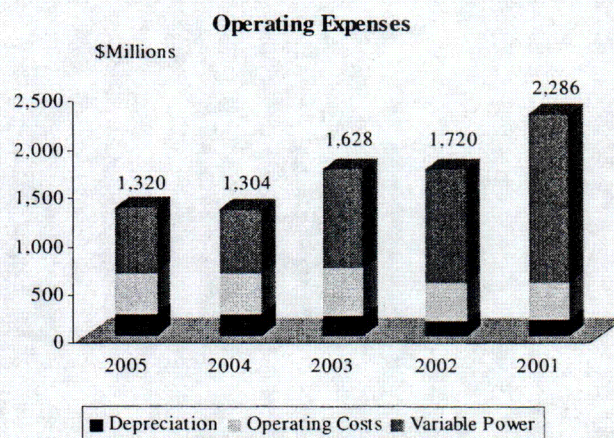
with 17% and 9% reductions, respectively, in combustion turbine and hydro production partially offset by increased coal-fired generation, primarily from Colstrip. Total generation met approximately 42% of PGE's retail load in 2005, compared to 43% in 2004.

The following table indicates PGE's total system load (including both retail and wholesale) for the last two years. Average variable power costs exclude unrealized gains and losses from derivative instruments and the effect of credits to purchased power and fuel costs related to PGE's power cost adjustment mechanisms, as discussed above.

	Megawatt-Hours/Variable Power Costs			
	Megawatt-Hours (thousands)		Average Variable Power Cost (Mills/KWh)	
	<u>2005</u>	<u>2004</u>	<u>2005</u>	<u>2004</u>
Generation	7,821	8,114	13.7	15.0
Term Purchases	11,705	12,017	35.3	30.9
Spot Purchases	<u>1,361</u>	<u>1,343</u>	57.4	41.4
Total System Load	<u>20,887</u>	<u>21,474</u>	31.3*	28.2*

(* includes wheeling costs)

Production, distribution, administrative and other expenses increased \$21 million (8%) from 2004 due primarily to increased employee benefit expenses (including medical and pension costs), the settlement of certain asserted claims, and an increase in distribution and preventive maintenance expenses. These were partially offset by a reduction in maintenance and other expenses at the Company's thermal generating plants.



Income taxes related to utility operations decreased \$11 million primarily due to lower pretax operating income.

Other Income (Miscellaneous) decreased \$5 million due primarily to the establishment of a \$10 million reserve related to the future refund to Multnomah County customers of previously-collected income taxes, pursuant to a settlement agreement. For further information, see "Class Action Lawsuit - Multnomah County Business Income Taxes" in "Financial and Operating Outlook" of this Item 7.

2004 Compared to 2003

PGE's net income in 2004 was \$92 million compared to \$60 million in 2003. Results for 2003 included after tax provisions totaling approximately \$19 million related to investigations into wholesale power market activities during 2000 and 2001, consisting of \$14 million related to amounts due the Company for wholesale electricity sales made in California and \$5 million related to a settlement agreement between PGE, the FERC, and other parties. In addition, results for 2003 have been restated to include an additional \$2 million after tax gain in the cumulative effect of a change in accounting principle. For further information, see Note 16, Restatement of Prior Period Financial Statements, in the Notes to Financial Statements.

The remaining increase in net income in 2004 was due primarily to improved margins on energy sales resulting from economic decisions related to the utilization of the Company's thermal generating assets and activities in the wholesale marketplace. In addition, 2003 margin reflects a disallowance by the OPUC of certain power purchase contracts in prices charged customers. These factors, along with lower interest charges and administrative expenses, more than offset the impact of retail energy sales that continued below the levels projected in the Company's most recent general rate case.

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

Operating Revenues (In Millions)	<u>2004</u>	<u>2003</u>	<u>Increase/ (Decrease)</u>
Retail Operating Revenues:			
Retail	\$ 1,311	\$ 1,328	\$ (17)
Direct Access Customer Revenues	<u>7</u>	<u>-</u>	<u>7</u>
Total Retail Revenues	<u>1,318</u>	<u>1,328</u>	<u>(10)</u>
Wholesale (Non-Trading)	107	393	(286)
Other Operating Revenues:			
Trading Activities - net	1	2	(1)
Other	<u>28</u>	<u>29</u>	<u>(1)</u>
Total Operating Revenues	<u>\$ 1,454</u>	<u>\$ 1,752</u>	<u>\$ (298)</u>
Energy Sold and Delivered (In Thousands of MWhs)			
Retail Energy Deliveries			
Retail Energy Sales	17,764	18,426	(662)
Energy Delivered to Direct Access Customers	<u>776</u>	<u>-</u>	<u>776</u>
Total Retail Energy Deliveries	<u>18,540</u>	<u>18,426</u>	<u>114</u>
Wholesale (Non-Trading)	2,539	9,966	(7,427)
Trading Activities	<u>9,699</u>	<u>13,551</u>	<u>(3,852)</u>
Total Energy Sold and Delivered	<u>30,778</u>	<u>41,943</u>	<u>(11,165)</u>

The decrease in Retail Revenues from 2003 was caused by lower energy sales. Retail energy sales decreased 4% due largely to a 22% decline in industrial sales, most of which was attributable to two large customers, with one now generating its own power requirements and the other now served by an ESS. The decrease in revenue from these two customers was approximately \$29 million, of which about half was attributable to the customer now served by an ESS. An additional \$18 million decrease in retail revenues resulted from the loss of other non-residential customers now served by ESSs. The reduction in industrial energy sales was partially offset by higher residential and commercial sales, which increased by about 2.4% and 1%, respectively, in 2004. An approximate 11,700 average increase in customers served, combined with significantly colder January weather, more than offset the effects of mild weather during the remainder of 2004. Also partially offsetting the effect of reduced industrial energy sales was an approximate 0.4% average rate increase for 2004. (For further information, see "Resource Valuation Mechanism" in "Financial and Operating Outlook" of this Item 7).

Lower wholesale revenues and energy sales resulted primarily from the adoption of EITF 03-11 in the fourth quarter of 2003. Beginning October 1, 2003, revenues and expenses related to non-trading energy activities that are not physically settled, formerly included on a "gross" basis within both Operating Revenues and Purchased Power and Fuel expense, are recorded on a "net" basis in Purchased Power and Fuel expense. This change resulted in a decrease in reported non-trading wholesale energy sales and purchases and related amounts in comparative financial statements. Although determination of the effect of the change on prior year reported revenues and expenses was not practicable, the change had no impact on reported net income. The remaining decrease in wholesale revenues was attributable to a 23% reduction in wholesale energy sales. The decrease was partially offset by a 7% increase in average prices, due primarily to higher natural gas prices and a reduction in regional hydro availability.

Other Operating Revenues approximated that of 2003, with increased revenue from the sale of transmission capacity more than offset by decreased gains on the sale of natural gas in excess of generating plant requirements, as power purchases in the wholesale market economically displaced more expensive gas-fired thermal generation.

Purchased Power and Fuel expenses for 2004 decreased \$361 million from 2003, primarily due to the adoption of EITF 03-11, which resulted in reductions to expense of \$296 million and \$90 million in 2004 and 2003, respectively. In addition, expenses for 2003 include a \$22.5 million (\$14 million after taxes) provision for uncollectible accounts receivable for wholesale electricity sales in the California market. (For further information, see "Receivables and Refunds on Wholesale Market Transactions" in "Financial and Operating Outlook" of this Item 7). The remaining \$132 million decrease from 2003 is largely attributable to a reduction in power purchased to meet a lower total system load requirement as well as a lower average variable power cost. Lower term power prices for power delivered in 2004 more than offset higher spot power prices during the year. Combined with a decrease in the average cost of both combustion turbine and coal-fired generation, PGE's average variable power cost decreased 1% from that of 2003 (for further information, see "Power and Fuel Supply" in "Financial and Operating Outlook" of this Item 7). Total Company generation increased 2% in 2004, with higher combustion turbine generation (due to the forced outage of Coyote Springs during part of 2003) partially offset by decreased coal-fired generation, due primarily to the Boardman plant's 2004 extended maintenance outage. PGE hydro production approximated that of 2003. Total generation met approximately 43% of PGE's retail load in 2004, compared to 40% in 2003.

The following table indicates PGE's total system load (including both retail and wholesale) for the last two years (excludes energy trading activities). Average variable power costs exclude the effect of provisions for uncollectible wholesale accounts receivable.

	Megawatt-Hours/Variable Power Costs			
	Megawatt-Hours (thousands)		Average Variable Power Cost (Mills/KWh)	
	<u>2004</u>	<u>2003</u>	<u>2004</u>	<u>2003</u>
Generation	8,114	7,922	15.0	15.6
Term Purchases	12,017	19,365	30.9	35.0
Spot Purchases	<u>1,343</u>	<u>2,404</u>	41.4	38.5
Total System Load	<u>21,474</u>	<u>29,691</u>	28.2*	32.2*

(* includes wheeling costs)

Production, distribution, administrative and other expenses increased \$10 million (4%) from 2003 due primarily to costs related to an extended maintenance outage at the Boardman coal plant, increased service restoration costs (net of insurance recovery) related to a five-day snow and ice storm in January 2004, and higher distribution expenses, including increased tree trimming requirements. A decrease in corporate overhead charges from Enron was largely offset by increases in both employee benefit expenses (including medical and pension costs) and customer service and support expenses. Corporate overhead charges billed by Enron, approximately \$14 million in 2003, were terminated for 2004.

Depreciation and Amortization expense increased \$20 million (9%) due partially to a \$9 million increase in amortization of regulatory assets (including costs related to implementation of Oregon's electricity restructuring law), the effects of which are fully offset within Operating Revenues. The remaining increase resulted from increased depreciation and amortization of utility plant due to normal property additions, and a reduction in the deferral of certain regulatory assets.

Income taxes related to utility operations increased \$7 million primarily due to higher taxable income.

Other Income (Miscellaneous) increased \$3 million. Results for 2003 included an \$8.5 million charge related to a settlement agreement between PGE, the FERC, and other parties related to investigations into prior years' wholesale power market activities. Partially offsetting the effect of this charge was a reduction in interest income in 2004, related primarily to lower remaining balances to be collected under the Company's 2000-2001 power cost adjustment mechanisms. A \$3 million reduction in tax benefits from 2003 was due primarily to the increase in income.

Interest Charges decreased \$10 million (13%) due to both a lower level of outstanding long-term debt in 2004 and to the replacement of higher rate debt in the second half of 2003.

Capital Resources and Liquidity

Review of Cash Flow Statement

Cash Provided by Operations is used to meet the day-to-day cash requirements of PGE. Supplemental cash is obtained from external borrowings, as needed.

A significant portion of cash from operations consists of charges that are recovered in customer revenues for depreciation and amortization of utility plant that require no current period cash outlay. The recovery from customers of prior capital expenditures through depreciation and amortization provides a source of funding for current and future cash requirements. Cash flows from operations can also be affected by changes in the price of power and fuel as well as by weather conditions, as temperatures outside the normal range can affect electricity usage and resultant cash flow.

Cash provided by operating activities totaled \$372 million in 2005 compared to \$340 million in 2004. The increase was due primarily to an approximate \$33 million reduction in payments for power and fuel purchases, a \$22 million increase in cash collateral deposits received from certain wholesale customers, a \$20 million increase related to the 2004 purchase and 2005 liquidation of short-term investments, and a \$4 million decrease in interest payments. These items were partially offset by a \$5 million increase in income tax payments to Enron, a \$32 million decrease in amounts received for sales of electricity, and a \$10 million contribution made to the Company's Pension Trust in 2005.

Existing cash and short term investments, along with cash provided by operations, were used to meet PGE's day-to-day requirements during 2005.

Investing Activities consist primarily of improvements to PGE's distribution, transmission, and generation facilities. The \$61 million increase in capital expenditures in 2005 is attributable to construction costs of Port Westward, the purchase of the Boardman coal handling facility (which was previously leased by the Company), and hydro relicensing activities. Other expenditures were related to the expansion of PGE's distribution system to support both new and existing customers within the Company's service territory.

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

During 2005, PGE retired \$18 million of First Mortgage Bonds, \$11 million of conservation bonds, and \$3 million of preferred stock. In July 2005, PGE paid a common stock dividend of \$150 million to Enron. No cash dividends on common stock were declared or paid in 2004. PGE paid \$1 million of preferred stock dividends in 2005 (classified as interest expense).

The issuance of additional First Mortgage Bonds and preferred stock requires PGE to meet earnings coverage and security provisions set forth in the Company's Articles of Incorporation and the Indenture of Mortgage and Deed of Trust securing the bonds. As of December 31, 2005, PGE has the capability to issue additional preferred stock and First Mortgage Bonds in amounts sufficient to meet its anticipated capital and operating requirements.

At December 31, 2005, PGE had a \$400 million five-year revolving credit facility with a group of commercial banks. The facility, which is unsecured, replaced the Company's \$50 million 364-day

revolving credit facility, which expired in May 2005, and a \$100 million three-year facility. It is available for general corporate purposes, with the maximum amount available to PGE for borrowings and/or the issuance of standby letters of credit. At December 31, 2005, PGE had utilized approximately \$17 million in letters of credit, with \$11 million related to wholesale trading activities and \$6 million related to Port Westward.

The facility allows PGE to borrow for one, two, three, or six months at a fixed interest rate established at the time of the borrowing, or at a variable interest rate for any period up to the then remaining term of the facility. The facility provides that all outstanding loans mature on the termination date of the facility, provided that such date may be extended for an additional year for those lenders who agree to an extension. The facility requires annual fees based on PGE's unsecured credit rating, and contains customary covenants and default provisions, including a requirement that limits consolidated indebtedness, as defined in the facility, to 65% of total capitalization. At December 31, 2005, the Company's indebtedness to total capitalization ratio, as calculated under the facility, was 41.7%.

Prior to the repeal of PUHCA 1935 by EPAct 2005, PGE had SEC approval to issue and sell unsecured short-term debt. Following the repeal of PUHCA 1935, PGE's issuance of short-term debt requires approval by the FERC. Pursuant to PGE's application filed in December 2005, the FERC issued an order on February 3, 2006 which authorizes the Company to issue short-term debt, in an amount not to exceed \$400 million outstanding at any one time, over the two-year period February 8, 2006 through February 7, 2008.

Cash Requirements

Access to short-term debt markets provides necessary liquidity to support PGE's current operating activities, including the purchase of electricity and fuel. Long-term capital requirements are driven largely by debt refinancing activities and capital expenditures for distribution, transmission, and generation facilities supporting both new and existing customers.

PGE's liquidity and capital requirements can be significantly affected by operating, capital expenditure, debt service, and working capital needs, including margin deposits related to wholesale trading activity. PGE's revolving credit facility supplements operating cash flow and provides a primary source of liquidity. PGE's ability to secure sufficient long-term capital at reasonable cost is determined by its financial performance and outlook, capital expenditure requirements (including the effects of these factors on the Company's credit ratings), and alternatives available to investors. The Company's ability to obtain and renew such financing depends on its credit ratings as well as on bank credit markets, both generally and for electric utilities in particular.

PGE's financial objectives include the balancing of debt and equity to maintain a low weighted average cost of capital while retaining sufficient flexibility to meet the Company's financial obligations. PGE's objective is to maintain a common equity ratio (common equity to total consolidated capitalization, including current debt maturities) of approximately 50%. Achievement of this objective while sustaining sufficient cash flow is necessary to maintain acceptable credit ratings and allow access to long-term capital at attractive interest rates. PGE's common equity ratios were 57.5% and 58.4% at December 31, 2005 and December 31, 2004, respectively.

As previously indicated, a significant portion of cash provided by operations consists of depreciation and amortization of utility plant which is recovered in rates. PGE estimates recovery of such charges to approximate \$175 million to \$215 million annually over the period 2006-2008. Combined with all other sources, cash provided by operations is estimated to range from \$155 million to \$295 million annually during the 2006-2008 period.

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

	<u>2006</u>	<u>2007</u>	<u>2008</u>
Capital expenditures (*)	\$305 - \$325	\$225 - \$245	\$280 - \$300
Long-term debt maturities	\$11	\$67	-

(*) Includes expenditures related to the construction of Port Westward (approximately \$117 for 2006 and \$16 for 2007) and for fish passage measures at the Pelton Round Butte hydroelectric project (approximately \$50 for 2008).

PGE's revolving credit facility may be used to fund any potential cash shortfall, with additional liquidity available, if necessary, from the issuance of long-term debt. Cash balances are temporarily invested primarily in government money market funds and short-term commercial paper that have remaining maturities of less than three months from the date of acquisition and are considered cash equivalents. Such investments are consistent with PGE's investment objectives to preserve principal, maintain liquidity, and diversify risk. Company investments are limited to investment grade securities (primarily short-term).

In July 2005, PGE declared and paid a cash dividend of \$150 million to Enron, the sole shareholder of the Company's common stock. PGE's equity ratio (as calculated under OPUC requirements) remains above the 48% level required by the Commission under terms of PGC's 1997 merger with Enron. PGE's common equity ratio also remains above the Company's 50% objective, as described above.

Following the issuance of new PGE common stock, currently expected to take place on or about April 3, 2006, the Company expects to pay regular quarterly common dividends. However, the declaration of common dividends is at the discretion of the Board of Directors and is not guaranteed. The amount of common dividends will depend upon PGE's results of operations and financial condition, future capital expenditures and investments, any applicable regulatory and contractual restrictions, and other factors that the Board of Directors considers relevant.

Credit Ratings

PGE's secured and unsecured debt are rated at investment grade by Moody's Investors Service (Moody's), Standard and Poor's (S&P), and Fitch Ratings (Fitch).

PGE's current credit ratings are as follows:

	<u>Moody's</u>	<u>S&P</u>	<u>Fitch</u>
First Mortgage Bonds	Baa1	BBB+	A-
Senior unsecured debt	Baa2	BBB	BBB+
Preferred stock	Ba1	BBB-	-
Commercial paper	Prime-2	A-2	F-2
Outlook:	Stable	Negative	Stable

Should Moody's or S&P (or both) reduce the credit rating on PGE's unsecured debt to below investment grade, the Company could be subject to requests by certain of its wholesale counterparties to post additional performance assurance collateral. On January 31, 2006, PGE had posted approximately \$15 million of collateral, consisting of \$11 million in letters of credit and \$4 million in

cash. Based on the Company's non-trading portfolio, estimates of current energy market prices, and the current level of collateral outstanding, as of January 31, 2006, the approximate amount of additional collateral that could be requested upon a single agency downgrade event to below investment grade is approximately \$56 million and decreases to approximately \$1 million by year-end 2006. The approximate amount of additional collateral that could be requested upon a dual agency downgrade event to below investment grade is approximately \$68 million and decreases to approximately \$1 million by year-end 2006.

In addition to collateral calls, a credit rating reduction could impact the terms and conditions of long-term debt issued in the future. Any rating reductions could also increase interest rates and fees on PGE's revolving credit facility, increasing the cost of funding the Company's day-to-day working capital requirements. PGE's financing arrangements do not contain ratings triggers that would result in an acceleration of the required interest and principal payments in the event of a ratings downgrade. Management believes that the Company's existing line of credit, access to the commercial paper market, and cash from operations provide it with sufficient liquidity to meet its day-to-day cash requirements.

Contractual Obligations and Commercial Commitments

The following indicates PGE's contractual obligations as of December 31, 2005 (in millions):

	Payments Due (*)						
	<u>Total</u>	<u>2006</u>	<u>2007</u>	<u>2008</u>	<u>2009</u>	<u>2010</u>	<u>After 2010</u>
Long-Term Debt	\$ 890	\$ 11	\$ 67	\$ -	\$ -	\$ 335	\$ 477
Interest on Long-Term Debt	253	59	56	54	54	30	-
Operating Leases	216	7	7	7	7	7	181
Purchase Obligations	404	192	43	54	33	10	72
Purchased Power and Fuel:							
Electricity Purchases	1,926	706	304	90	90	91	645
Capacity Contracts	240	24	24	24	24	24	120
Natural Gas Agreements	138	35	17	17	15	13	41
Public Utility Districts	88	7	7	8	8	7	51
Coal and Transportation Agreements	55	13	13	14	3	3	9
Total	<u>\$4,210</u>	<u>\$1,054</u>	<u>\$ 538</u>	<u>\$ 268</u>	<u>\$ 234</u>	<u>\$ 520</u>	<u>\$1,596</u>

(*) Interest on long-term debt is not estimated beyond 2010. Contributions to the Company's pension plan are estimated at \$0 for 2006 through 2010 and not determinable thereafter.

Other Financial Obligations

PGE has entered into long-term power purchase contracts with certain public utility districts in the state of Washington under which PGE has acquired a percentage of the output (Allocation) of four hydroelectric projects (the Rocky Reach, Priest Rapids, Wanapum and Wells hydroelectric projects). The Company is required to pay its proportionate share of the operating and debt service costs of the projects whether or not they are operable. The contracts further provide that, should any other purchaser of output default on payments as a result of bankruptcy or insolvency, PGE will be allocated a pro rata share of both the output and the operating and debt service costs of the defaulting purchaser.

For the Rocky Reach, Wanapum and Wells projects, PGE will be allocated up to a cumulative maximum of 25% of the defaulting purchaser's percentage Allocation. For the Priest Rapids project, PGE will be allocated up to a cumulative maximum of 7% of the total project.

For details of annual costs by project, including debt service, see Note 7, Commitments and Guarantee, in the Notes to the Financial Statements.

Off-Balance Sheet Arrangements

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

Critical Accounting Policies and Estimates

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

Regulatory Accounting

As a regulated utility, PGE prepares its consolidated financial statements in accordance with the provisions of SFAS No. 71, Accounting for the Effects of Certain Types of Regulation. In order to apply the accounting policies and practices of SFAS No. 71, regulated companies must satisfy the following conditions: (i) rates are established by or subject to approval by an independent regulator; (ii) rates are designed to recover specific costs of delivering service; and (iii) in view of demand for service, it is reasonable to assume that rates can be charged and collected from customers at levels that will recover the Company's costs. SFAS No. 71 requires companies that meet these conditions to reflect the impact of regulatory decisions in their consolidated financial statements and requires that certain costs be deferred as regulatory assets until matching revenues are recognized. Similarly, certain items may be deferred as regulatory liabilities and amortized to the income statement as rates to customers are reduced.

PGE continues to meet each of above conditions for continued application of SFAS No. 71 in its financial statements. The Company is subject to jurisdiction of the OPUC, which approves PGE's retail rates, ensuring that they provide an opportunity for the Company to earn a fair return on its investment. The Company's rates, as authorized by the OPUC, are based on the cost of service and are designed to recover operating expenses and capital costs associated with generation, transmission and distribution assets used to provide regulated service to customers. Although changes in such rates are subject to a formal ratemaking process, it is expected that the OPUC will continue to recognize all prudently-incurred costs and authorize rates that allow for their recovery. In addition, the OPUC has

authorized an RVM process by which base rates are adjusted annually for changes in projected power costs. The RVM has enabled the Company to more timely reflect changes in power costs in customer prices. (For further information, see "Resource Valuation Mechanism" in "Financial and Operating Outlook" of this Item 7). Finally, PGE's retail operations are conducted within a state-approved service area in which there is no retail competition, other than that related to the state's customer choice program. Participation in this program, implemented in 2002, has not had a material impact on PGE's regulated operations, with only about 7% of the Company's total retail load served by ESSs. The large majority of PGE's customers continue to take service under rate tariffs determined by the cost of service. Changes in demand and level of competition for PGE's regulated services have not materially impacted the Company's ability to recover its costs through regulation.

PGE periodically assesses the continued applicability of SFAS No. 71 to its business, considering both the current and anticipated future rate environment and related accounting guidance, as outlined in SFAS No. 101, Regulated Enterprises - Accounting for the Discontinuation of Application of SFAS No. 71, and EITF Issue 97-4, Deregulation of the Pricing of Electricity - Issues Related to the Application of SFAS No. 71 and SFAS No. 101. As PGE continues to fully meet each of the required conditions, the Company has recorded regulatory assets and liabilities in the amount of \$217 million and \$524 million, respectively, at December 31, 2005. PGE expects to fully recover these regulatory assets, and refund these regulatory liabilities, through its rates. If future recovery of costs ceases to be probable, however, PGE would be required to write off these regulatory assets and liabilities. In addition, if at some point in the future PGE determines that all or a portion of its utility operations no longer meet the criteria for continued application of SFAS No. 71, the Company would be required to adopt the provisions of SFAS No. 101, which would require the Company to write off those regulatory assets and liabilities related to operations that no longer meet requirements of SFAS No. 71. Discontinuation of SFAS No. 71 could have a material impact on the Company's results of operations and financial position.

Asset Retirement Obligations

SFAS No. 143, as interpreted by FASB Interpretation No. 47, requires the recognition of Asset Retirement Obligations (AROs), measured at estimated fair value, for legal obligations related to dismantlement and restoration costs associated with the retirement of tangible long-lived assets in the period in which the liability is incurred. Upon initial recognition of AROs that are measurable, the probability weighted future cash flows for the associated retirement costs, discounted using a credit-adjusted risk-free rate, are recognized as both a liability and as an increase in the capitalized carrying amount of the related long-lived assets. Due to the long lead time involved, a market-risk premium cannot be determined for inclusion in future cash flows. Capitalized asset retirement costs are depreciated over the life of the related asset, with accretion of the ARO liability classified as an operating expense on the Statement of Income. On the Statement of Income, AROs related to Utility plant are included in Depreciation and Amortization expense, with those related to Other property included in Other Income (Deductions). In accordance with requirements of SFAS No. 143, accumulated asset retirement removal costs that do not qualify as AROs have been reclassified from Accumulated depreciation to Regulatory liabilities on the Balance Sheet.

Trojan Decommissioning

In early 1993, PGE ceased commercial operation of Trojan and began the decommissioning process. The original Trojan decommissioning cost estimate was prepared by an engineering firm with subsequent updates by PGE, due primarily to the effects of inflation and the timing of certain activities. The net estimated liability for Trojan decommissioning costs as of December 31, 2005 was \$107 million, measured at estimated fair value pursuant to provisions of SFAS No. 143. PGE's current retail prices include recovery of \$14 million annually through 2011, which amount is based on the

decommissioning cost estimate. These amounts are deposited in an external trust fund, which reimburses PGE for costs expended under the decommissioning plan. The decommissioning estimate includes amounts for equipment removal, embedded pipe remediation, surface decontamination, non-radiological decontamination, and on-site spent nuclear fuel storage (until permanent storage is provided by the USDOE). Estimating the cost of decommissioning activities over a period extending to 2023 is inherently subjective and complex. Such estimates may vary because of changes in regulatory requirements, technology, labor and material costs, and waste burial. In addition, timing of actual activities may differ from that established in the decommissioning plan, which may also cause actual costs to vary from those estimated. Remaining decommissioning activities consist of demolition of the existing structures and long-term operation and decommissioning of the Independent Spent Fuel Storage Installation.

Management does not expect actual future decommissioning costs to change significantly from the current estimate. However, if actual costs significantly exceed the previously estimated amount, funds collected through rates may not be adequate to cover actual decommissioning costs and may require that PGE utilize available cash and a credit facility to advance funds to the trust to cover any near term shortfall. Recovery of any such shortfall from customers would require OPUC approval.

Loss Contingency Reserves

Contingencies are evaluated based on SFAS No. 5, Accounting for Contingencies, using the best information available. A material loss contingency is accrued and disclosed when it is probable that an asset has been impaired or a liability incurred and the amount of the loss can be reasonably estimated. If a range of possible loss is established, the minimum amount in the range is accrued, unless some other amount within the range appears to be a better estimate. If the probable loss cannot be reasonably estimated, no accrual is recorded, but the loss contingency is disclosed to the effect that it cannot be reasonably estimated. Material loss contingencies are disclosed when it is reasonably possible that an asset has been impaired or a liability incurred. Reserves established reflect management's assessment of inherent risks, credit worthiness, and complexities involved in the collection process.

Receivables and Refunds - California Wholesale Market

As of December 31, 2005, PGE has net accounts receivable balances totaling approximately \$63 million for wholesale electricity sales made to the California Independent System Operator (ISO) and the California Power Exchange (PX) from November 2000 through February 2001. The Company estimates that the majority of this amount was for sales by the ISO and PX to Southern California Edison Company and Pacific Gas & Electric Company (PG&E). In 2001, the PX filed for bankruptcy and PG&E filed a voluntary petition for relief under the provisions of Chapter 11 of the federal Bankruptcy Code. Although both entities have emerged from their bankruptcy proceedings as reorganized debtors, not all claims filed in the proceedings, including those filed by PGE, have been resolved.

In 2002, the FERC ordered refunds for non federally-mandated transactions made between October 2, 2000 and June 20, 2001 in the spot markets operated by the ISO and PX. A methodology to calculate such refunds was also established by the FERC. The FERC has indicated that any potential refunds can be offset by accounts receivable, thereby mitigating the effect of potential refunds on PGE. Calculated interest on potential refunds will likewise be offset by interest on accounts receivable.

The FERC methodology for calculating potential refunds, initially established in July 2001, was revised in March 2003, significantly increasing the refund amount initially estimated. Accordingly, a \$17.5 million reserve established at December 31, 2002 was increased to \$40 million at December 31, 2003. Pursuant to FERC guidelines, PGE in September 2005 filed a cost recovery study to prove that the Company, in order to cover its costs, should be permitted to recover additional revenues in excess of the mitigated prices. The study showed that PGE's costs to serve the ISO and PX markets exceeded the revenues PGE will receive from those mitigated sales by over \$27 million. By order issued January 26, 2006, the FERC conditionally accepted PGE's September cost filing, subject to PGE making a compliance filing to eliminate certain costs, to include additional revenues, and to supplement its analysis with additional cost, load, and resource data. On February 10, 2006, PGE submitted a compliance filing with two cases, in the alternative, that incorporated the FERC-required changes. The compliance filing shows a revenue deficit for PGE's sales to the ISO and PX (that is, a reduction to PGE's refund liability) of from approximately \$20 million to approximately \$30 million, depending on the methodology ultimately accepted by the Commission. Third parties have challenged PGE's compliance filing and requested that it be rejected in its entirety or that the cost offset be reduced to zero, and PGE has filed a response to those challenges. The procedure established by the FERC in the January 26 order also required each seller whose cost filing has been accepted to incorporate in its filing final ISO and PX settlement data and to provide its revised filing to the ISO and PX for further processing.

PGE believes that the FERC erred in certain of its findings in the January 26 order, and has filed a request for rehearing as to several issues. Due to the continuing uncertainty related to these matters, PGE has made no adjustment to the \$40 million reserve previously established for the Company's potential liability. As an unresolved legal and regulatory matter, both the refund methodology and estimated amount may vary significantly in the future, which could have a material impact on PGE's results of operations.

Price Risk Management

PGE engages in price risk management activities in its electric business, utilizing derivative instruments such as electricity forward, swap, and option contracts and natural gas forward, swap, option, and futures contracts to protect the Company against variability in expected future cash flows due to associated price risk and to minimize net power costs for retail customers. Derivative contracts are accounted for under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended. Certain derivative instruments are recorded at fair value on the balance sheet and, to the extent these instruments are included in the Company's RVM, changes in fair value are offset with a regulatory asset or regulatory liability under SFAS No. 71 to reflect the effects of regulation. As these contracts are settled, the regulatory asset or regulatory liability is reversed. Until the settlement of all derivative instruments related to such activities, PGE will record changes in fair value in current earnings. Changes in fair value of instruments not included in the RVM are reflected in either income or comprehensive income. For further information, see "Resource Valuation Mechanism" in "Financial and Operating Outlook" of this Item 7.

Mark-to-Market

Marking a contract to market consists of reevaluating the market value at the end of each reporting period for the entire term of the contract and recording any change in value (difference between the contract price and current market price) in either earnings or other comprehensive income for the period. Valuation of these financial instruments reflects management's best estimates of market prices, including closing NYMEX and over-the-counter quotations, time value of money, and volatility factors underlying the commitments.

Determining the fair value of these contracts requires the use of prices at which a buyer or seller could currently contract to purchase or sell a commodity at a future date (termed "forward prices"). Forward price "curves" are used to determine the current fair market price of a commodity to be delivered in the future. PGE's forward price curves are created by utilizing actively quoted market indicators received from electronic and telephone brokers, industry publications, NYMEX, and other sources, and are validated using independent publications. Estimates used in creating forward price curves can change with market conditions and can be materially affected by unpredictable factors such as weather and the economy. The difference between PGE's forward price curves and four independently published price curves averages 1%. The difference at any single location, delivery date and commodity is less than 5%.

For purchases and sales of forward physical or financial contracts, the mark-to-market value is the present value of the difference between PGE's contracted price and the forward price multiplied by the total quantity of the contract. For option contracts, a theoretical value is computed using standard financial models that utilize price volatility, price correlation, time to expiration, interest rate and price curves. The mark-to-market of these options is the difference between the premium paid or received and the theoretical value.

Pension Plan Returns

Pension expense is dependent on several assumptions used in the actuarial valuation of the plan. Primary assumptions include the discount rate, the expected return on plan assets, and mortality rates. These assumptions are evaluated by PGE, reviewed annually with the plan actuaries and trust investment consultants, and updated in light of market changes, trends, and future expectations. Significant differences between assumptions and actual experience could have a material impact on PGE's financial condition and results of operations.

PGE's pension discount rate is based on assumptions regarding rates of return on long-term high quality bonds. Assumptions regarding the expected rate of return on plan assets are based on historical and projected average rates of return for current asset classes in the plan investment portfolio. The expected rate of return reflects expected future returns for the portfolio, and was used in determining net periodic pension income for the year. At December 31, 2005, the plan's assets were comprised of approximately 67% equity securities and 33% debt securities.

Changes in actuarial assumptions can also materially affect net periodic pension income. A 0.25% reduction in the expected long-term rate of return on plan assets would have reduced 2005 pension income by approximately \$1.2 million. A 0.25% reduction in the discount rate would have reduced 2005 pension income by approximately \$1.6 million.

In 2005, PGE updated the mortality rate assumptions used for pension benefits. The impact of this change was an increase of \$14 million in the accumulated benefit obligation at December 31, 2005.

Transactions with Related Parties

PGE services to affiliated companies consist primarily of employee and administrative services. The Company also receives services from affiliated companies for certain insurance coverage. Transactions with affiliated companies are subject to regulation by the OPUC. Most affiliated interest transactions are made under a Master Service Agreement (MSA) filed with the Commission. Under OPUC regulations, services provided to affiliates by PGE are charged at the higher of cost or market, while affiliated services received by PGE are charged at the lower of cost or market.

Trading Activities Accounted for at Fair Value

PGE discontinued its trading activities in early 2005, with remaining transactions settled by December 31, 2005. Prior to discontinuance, PGE's trading activities utilized electricity forward, swap, and option contracts and natural gas forward, swap, option, and futures contracts to participate in electricity and natural gas markets. Valuation of these instruments reflects management's best estimates of market prices, including closing NYMEX and over-the-counter quotations, time value of money, and volatility factors underlying the commitments.

The following table indicates fair value, and changes in fair value, of PGE's trading contracts in 2005 and 2004 (in millions):

	Unrealized Gain (Loss)	
	2005	2004
Unrealized gain of contracts as of January 1	\$ 1	\$ -
Less contracts realized during year:		
Contracts entered in prior years	(1)	-
Contracts entered in current year	-	-
Change in fair value attributable to market changes:		
Contracts entered in prior years	-	-
Contracts entered in current year	-	1
Unrealized gain of contracts as of December 31	\$ -	\$ 1

Financial and Operating Outlook

Retail Customer Growth and Energy Deliveries

Weather adjusted retail energy deliveries to PGE and ESS customers increased 0.8% in 2005 compared to 2004. The increase was due primarily to 1.4% and 2.6% increases, respectively, for commercial and industrial customers. Increased industrial usage was largely attributable to a single large customer that normally generates its own power requirements, but which purchased energy from the Company during 2005. Weather adjusted residential energy deliveries were down 0.7% compared to 2004, as a reduction in average usage was only partially offset by an approximate 11,000 increase in the average number of customers served. PGE forecasts total weather adjusted energy deliveries to PGE and ESS customers to increase by approximately 2% in 2006.

Power and Fuel Supply

Wholesale power market products, along with PGE's base of thermal and hydroelectric generating capacity, currently provide the Company the flexibility to respond to seasonal fluctuations in the demand for electricity from its retail and wholesale customers. Although surplus generation has diminished in recent years due to economic and population growth in the western United States, the recent construction of new generating plants has increased the region's capacity to meet its power needs. The Company anticipates that an active wholesale market and generating capacity within the WECC will provide wholesale energy to supplement its generation and purchases under existing firm power contracts.

Early forecasts indicate that regional hydro conditions will approximate average levels in 2006. Volumetric water supply forecasts for the Pacific Northwest, prepared by the Northwest River Forecast Center in conjunction with the Natural Resources Conservation Service and other cooperating agencies, indicate the projected January-to-September 2006 runoff (as measured at The Dalles, Oregon) at 98% of normal, compared to actual runoffs of 74% in 2005 and 77% in 2004. In 2006, hydro conditions in the Clackamas and Deschutes river systems, where PGE's facilities are located, are currently projected to be 108% and 110% of normal, respectively, compared to actual runoffs of approximately 72% and 87% of normal, respectively, in 2005.

Factors that could affect the availability and price of purchased power and fuel include weather conditions in the Northwest and Southwest, as well as the performance of major generating facilities in both regions. In addition, market prices for natural gas increased significantly in 2005 due to the combined effects of severe hurricanes in the Gulf of Mexico and record hot weather in the United States. Such price increases could, in the longer term, affect the cost of natural gas required to fuel PGE's combustion turbine generating plants as well as prices of power purchased in the wholesale market.

Price Risk Management - As PGE's primary business is to serve its retail customers, it uses derivative instruments to manage its exposure to commodity price risk and to minimize net power costs to serve customers. Under SFAS No. 133, as amended, PGE records unrealized gains and losses in earnings in the current period for derivative instruments that do not qualify for either the normal purchases and normal sales exception or cash flow hedge accounting. The timing difference between the recognition of gains and losses on certain derivative instruments and their realization and subsequent recovery in rates is recorded as a regulatory asset or regulatory liability to reflect the effects of regulation under SFAS No. 71. Derivative instruments that qualify for the normal purchases and normal sales exception are recorded in earnings on a settlement basis, and cash flow hedges are recorded in OCI until they can offset the related results on the hedged item in the income statement.

From the time prices are set in the RVM process until the end of the RVM period, any changes to electricity and natural gas prices used in the RVM will result in unrealized gains and losses to be recorded in earnings in the current period on existing and new derivative instruments that do not qualify for the normal purchases and normal sales exception or cash flow hedges. Price movements in electricity and natural gas markets cause PGE to make power and natural gas purchases and sales decisions around the economic dispatch of its own generation. Derivative instruments that qualify for the normal purchases and normal sales exception or cash flow hedges, and forecasted transactions related to these decisions are not recorded in earnings in the current period, but are recognized in earnings when the contracts are settled in future periods. As a result, this timing difference may create earnings volatility between reporting periods.

Future Ownership of PGE

Enron's Chapter 11 Plan became effective on November 17, 2004. Although PGE was not included in the bankruptcy, the common stock of PGE held by Enron is one of the assets of the bankruptcy estate. Under the Chapter 11 Plan, Enron will distribute new PGE common stock to the Debtors' creditors. Current PGE common stock held by Enron will be cancelled and 62,500,000 shares of new PGE common stock without par value will be distributed over time to the Debtors' creditors. Initially, PGE will issue at least 30 percent of the new PGE common stock to the Debtors' creditors that hold allowed claims, with the remainder issued to a Disputed Claims Reserve (DCR) where it will be held to be released over time to the Debtors' creditors holding allowed claims in accordance with the Chapter 11 Plan.

The issuance of new PGE common stock is expected to take place on or about April 3, 2006. Following issuance of the new PGE common stock to the Debtors' creditors and the DCR, PGE will no longer be a subsidiary of Enron.

The registered owner of the new PGE common stock held in the DCR will be the Disbursing Agent associated with the DCR. The Disbursing Agent will oversee the release of new PGE common stock from the DCR to the Debtors' creditors that hold allowed claims. All shares of new PGE common stock held in the DCR will be voted by the Disbursing Agent at the direction of the Disputed Claims Reserve Overseers (DCRO). The DCRO is currently comprised of those individuals who serve on Enron's Board of Directors.

The distribution of new PGE common stock has been approved by all required regulatory agencies. The OPUC order approving the distribution (OPUC Order) includes 17 conditions that relate to, among other things: maintenance of PGE's financial strength during the conclusion of the Enron bankruptcy process, certain indemnifications for PGE from Enron related to Enron employee benefit plans and taxes, certain service quality measures, and additional direct access options for commercial and industrial customers. The indemnification is expected to be included in a separation agreement between Enron and PGE, which is expected to be executed at the time of the issuance of new PGE common stock.

On February 10, 2006, the City of Portland appealed the OPUC Order in both the Marion County Circuit Court and the Oregon Court of Appeals. The City filed its appeals in both courts due to the jurisdictional uncertainty created by new Oregon law governing appeals of OPUC decisions. In its appeal to the Circuit Court, the City alleges that the OPUC made its decision on an inadequate record, failed to enter adequate findings in support of its decision, abused the discretion granted it by Oregon law, and based its decision on a statute that constituted an unlawful delegation from the Oregon Legislature. The City requests the OPUC Order be modified, reversed or remanded. In the Court of Appeals filing, the City alleges that it is an aggrieved party and asks for judicial review without further details. On February 23, 2006 the OPUC filed a Motion to Hold Case in Abeyance with the Marion

County Circuit Court in order to seek summary determination from the Court of Appeals regarding the proper court to hear the City's appeal. The City and other defendants to the action, including PGE, did not oppose the motion. The Circuit Court has not ruled on this motion.

On February 13, 2006, the URP filed with the OPUC an application for reconsideration of the OPUC Order. The URP requests that the OPUC reconsider its order in light of a new Oregon Statute (Senate Bill 408), governing the rate treatment of income taxes included by Oregon utilities in rates. The URP alleges the stock distribution would allow PGE to deconsolidate for income tax purposes and frustrate future rate benefits Senate Bill 408 would allegedly produce. On February 28, 2006, PGE, CUB, and the OPUC staff filed oppositions to URP's application for reconsideration. Also on February 28, 2006, the City filed in support of URP's application and added new grounds for reconsideration of the OPUC Order. PGE filed in opposition to the City's new grounds for reconsideration on March 13, 2006. The OPUC has 60 days from the filing of an application for reconsideration to act on the application or it is deemed denied.

PGE has filed an original listing application with the NYSE for the listing of the new PGE common stock under the ticker symbol POR.

Enron has also indicated that, in accordance with its ongoing efforts to maximize the value of the Enron bankruptcy estate, it will continue to consider credible offers to purchase PGE's common stock until the new PGE common stock is issued. Following issuance of the new PGE common stock, approval of any offer to purchase the new PGE common stock from the DCR will be the responsibility of the DCRO, in accordance with guidelines approved by the Bankruptcy Court.

Enron Bankruptcy

Commencing on December 2, 2001, and from time to time thereafter, Enron Corp., along with certain of its subsidiaries, filed to initiate bankruptcy proceedings under Chapter 11 of the federal Bankruptcy Code. Enron's Chapter 11 Plan became effective on November 17, 2004. The Chapter 11 Plan and the related disclosure statement provide information about Chapter 11 Plan and are available at Enron's website located at www.enron.com/corp/por and the Bankruptcy Court's website located at www.nysb.uscourts.gov and at the website maintained at the direction of the Bankruptcy Court at www.elaw4enron.com.

In addition to the bankruptcy, numerous shareholder and employee class action lawsuits have been initiated against Enron, its former independent accountants, legal advisors, executives, and board members. In addition, Enron has been investigated by several Congressional committees and state and federal regulators, including the FERC and the State of Oregon. PGE has been included in requests for documents related to Congressional and regulatory investigations, with which it is fully cooperating. In addition to these general effects, PGE may have potential exposure to certain liabilities and asset impairments as a result of Enron's bankruptcy. These are:

Pension Plans

The Pension Benefit Guaranty Corporation (PBGC) insures pension plans, including the Enron Corp. Cash Balance Plan (the Enron Plan) and the pension plans of other Debtors. Enron's management has informed PGE that the PBGC filed claims for unfunded benefit liabilities (the UBL Claims) with respect to the Enron Plan and the plans of the other Debtors (Pension Plans). Pursuant to an order of the Bankruptcy Court, Enron created a reserve fund equal to the amount of the maximum PBGC exposure, as delineated in the PBGC UBL Claims, of \$321.8 million. This reserve provides security to the PBGC, and limits the possibility of the PBGC seeking to assert its UBL Claims against PGE and other Enron affiliates for any underfunding of the Pension Plans.

On June 3, 2004, the PBGC filed a complaint (PBGC Complaint) in the District Court for the Southern District of Texas against Enron seeking, among other things, termination of the Pension Plans. On September 12, 2005, in a joint hearing, the U.S. District Court for the Southern District of Texas, Houston Division (District Court) and the Bankruptcy Court approved a settlement (Settlement) with the PBGC and the plaintiffs in the class action litigation styled Pamela M. Tittle, et al, v. Enron Corp., et al, Civil Action No. H-01-3913, U.S. District Court for the Southern District of Texas, Houston Division (Tittle Action) and the United States Department of Labor (DOL) in the litigation styled Elaine L. Chao v. Enron Corp., et al. (DOL Action). Under the Settlement, the Tittle Action plaintiffs and the DOL will have a shared general unsecured claim of \$356.25 million and receive distributions pursuant to Enron's Chapter 11 Plan. Further, as a result of the Settlement, the PBGC Complaint and all actions in the Bankruptcy Court on the PBGC claims against the Debtors with respect to the Pension Plans have been stayed and should, by the terms of the Settlement, be dismissed with prejudice and Enron is proceeding with the standard termination of the Pension Plans. As a result, any need for the PBGC to attempt to collect from PGE any liability related to the Enron Plan should be eliminated.

Income Taxes

Under U.S. Treasury Department regulations, each member of a consolidated group in any year is severally liable for the tax liability of the consolidated group for that year. PGE has been a member of the Enron consolidated tax group since July 2, 1997, except for the period from May 8, 2001 to December 23, 2002 when PGE was not a member and filed its own consolidated tax returns. Enron's consolidated tax returns for all years through 2001 have been examined by the IRS and settlement has been reached, eliminating any further assessment of tax, interest or penalties. Enron's consolidated tax returns for 2002 and 2003 are currently being examined by the IRS. PGE remains potentially severally liable for any portion of any claim allowed in the bankruptcy that the IRS does not collect from the Debtors, or that is not settled by the reduction of any refund due to Enron.

OPUC Stipulation

One of the conditions in the OPUC Order is that, upon the issuance of the new PGE common stock, Enron agrees to provide indemnification to PGE for, among other things, any liabilities related to Enron-sponsored employee benefit plans (including the Enron Plan) and any liabilities related to taxes that may be imposed as the result of PGE's membership in Enron's consolidated tax group. These indemnifications are expected to be included in a separation agreement between Enron and PGE, which is expected to be executed at the time of the issuance of new PGE common stock.

Management Assessment

PGE management believes that the possibility of a material liability to PGE related to the Enron Plan or any IRS assessment against the Enron consolidated group for income taxes, interest, and penalties is remote.

Energy Policy Act of 2005

EPAct 2005, signed into law on August 8, 2005, significantly revised the Federal Power Act and Natural Gas Act. It also changed certain provisions of the Public Utility Regulatory Policies Act of 1978 (PURPA) regarding qualifying facilities and enacted tax incentives for the development of renewable and cleaner-fuel electric generating resources and for other electric and gas related purposes. EPAct 2005 includes transmission and reliability measures, including a plan for mandatory reliability standards to be developed and enforced by an electric reliability organization, which would

be under the FERC's jurisdiction. EAct 2005 also gave the FERC enhanced oversight of power and transmission markets.

EAct 2005 repealed PUHCA 1935 and enacted PUHCA 2005, effective February 8, 2006. Under PUHCA 2005, certain functions of the SEC are transferred to the FERC, including access to holding company books and records and determining the appropriate allocation of costs in certain affiliate transactions. In addition, PUHCA 2005 grants state regulatory commissions access to the books and records of holding companies and their subsidiaries if such access is necessary for the effective discharge of the state commission's jurisdictional responsibilities. In December 2005, the FERC issued its final rules implementing PUHCA 2005, which rules are now effective.

EAct 2005 also modifies and expands the FERC's authority and review of proposed utility mergers and acquisitions and disposition of assets related to wholesale sales.

PGE does not expect EAct 2005 to have a material impact on the Company's operations or financial results.

New Oregon Law - Utility Rate Treatment of Income Taxes

A new law, Oregon Senate Bill 408, seeks to adjust the way that PGE and most other Oregon investor-owned electric and gas utilities collect income taxes from ratepayers. Senate Bill 408 attempts to more closely match amounts collected under the ratemaking process with income taxes paid to governmental entities by investor-owned utilities or their consolidated group. It requires that utilities file reports with the OPUC by October 15 of each year regarding the amount of taxes paid by the utility or its consolidated group (with certain adjustments), as well as the amount of taxes authorized to be collected in rates, as defined by the statute. If the OPUC determines that the difference between the two amounts is greater than \$100,000, the Commission is to require the utility to establish an "automatic adjustment clause" to adjust rates.

PGE's initial report was filed on October 14, 2005 for the calendar years 2002, 2003, and 2004, based on temporary rules established by the OPUC. The report indicated that, for each year, the difference between "taxes authorized to be collected" and "taxes paid" was greater than \$100,000. However, under the law the first adjustment under the automatic adjustment clause applies only to taxes paid to units of government and collected from ratepayers on or after January 1, 2006.

Considerable uncertainty exists regarding the new law, with several issues subject to interpretation by the OPUC. In December 2005, Oregon's Attorney General issued an opinion that provides guidelines for implementation of the new law. PGE is participating in the Commission's comprehensive rule-making process. Until the Commission issues rules that implement the law, its impact on customers and utilities will be difficult to assess. In addition, it is expected that such rules may be challenged in the courts.

PGE continues to evaluate the potential effects of the new law. For the first quarter of 2006, PGE will continue to be a member of Enron's consolidated group for filing consolidated federal and state income tax returns. Based on the temporary rules, PGE anticipates that there will be material differences between taxes "authorized to be collected" and "taxes paid" in 2006, although the amount of those differences cannot be fully assessed until final rules are adopted. Accordingly, this could have a material adverse affect on the Company's earnings in 2006.

On December 30, 2005, PGE filed with the OPUC an "Application for Deferred Accounting of Expenses Associated with Utility Tax Liability" to complement the automatic adjustment clause described above. The purpose of the proposed deferral is to prevent either the financial enrichment or

financial harm to the Company that may occur if the permanent rules in Senate Bill 408 are designed with the use of fixed reference points for margins and effective tax rates from a rate making proceeding. The deferred amount would reflect the tax effect of the difference between PGE's implied operating costs under a fixed margin assumption and the Company's actual operating costs.

Complaint and Application for Deferral - Income Taxes

On October 5, 2005, the URP and Ken Lewis (Complainants) filed a Complaint with the OPUC alleging that, since September 2, 2005 (the effective date of Oregon Senate Bill 408), PGE's rates are not just and reasonable and are in violation of Senate Bill 408 because they contain approximately \$92.6 million in annual charges for state and federal income taxes that are not being paid to any government. The Complaint requests that the OPUC order the creation of a deferred account for all amounts charged to ratepayers since September 2, 2005 for state and federal income taxes, less amounts actually paid by or on behalf of PGE to the federal and state governments for income taxes.

Also on October 5, 2005, the Complainants filed an Application for Deferred Accounting with the OPUC, claiming that PGE is charging ratepayers \$92.6 million annually for federal and state income taxes that are not being paid, and that such charges are not fair, just and reasonable. The Application for Deferred Accounting requests that revenue due to the estimated PGE liabilities for federal and state income taxes, less any amounts of federal and state income taxes paid by PGE or on behalf of PGE, be deferred for later incorporation in rates.

On December 27, 2005, the OPUC issued a Joint Ruling to hold the Complaint and Deferred Accounting application in abeyance pending rehearing of an order previously issued by the OPUC in a rate proceeding involving another Oregon electric utility. Management cannot predict the ultimate outcome of these matters or estimate any potential loss.

Class Action Lawsuit - Multnomah County Business Income Taxes

In January 2005, David Kafoury and Kafoury Brothers, LLC filed a class action lawsuit in Multnomah County Circuit Court against PGE on behalf of all PGE customers who were billed on their electric bills and paid amounts for Multnomah County Business Income Taxes (MCBIT) after 1996. The plaintiffs alleged that during the period 1997 through the third quarter 2004, PGE collected in excess of \$6 million from its customers for MCBIT that was never paid to Multnomah County. The charges were billed and collected under OPUC rules that allow utilities to collect taxes imposed by the county. As a member of Enron's consolidated income tax return, PGE paid the tax it collected to Enron. The plaintiffs sought judgment against PGE for restitution of MCBIT collected from customers plus interest, recoverable costs, and reasonable attorney fees. The plaintiffs filed an amended complaint in February 2005, adding claims for fraud, unjust enrichment, conversion, statutory violations, and seeking punitive damages.

In May 2005, the Court granted PGE's motion for a stay for all purposes until the OPUC's issuance of a declaratory ruling in response to questions by PGE as to whether OPUC rules authorized PGE collections of the MCBIT and whether any refunds to customers were controlled by an OPUC three-year limitation for billing adjustments. In October 2005, the OPUC issued an order that determined that Commission rules authorized PGE collections of the MCBIT from Multnomah County customers but did not require that PGE calculate them in any particular way. Because the OPUC did not find that PGE had violated its rule, the Commission did not answer whether its three-year limitation on billing adjustments applied.

On December 28, 2005, the parties agreed to a settlement by which PGE will make refunds and payments totaling \$10 million, inclusive of interest and plaintiffs' attorney fees, costs, and expenses as

approved by the Court's final order. The settlement includes no admission of liability or wrongdoing by PGE. Distribution to customers is limited to amounts collected during the period 1999 through 2005. PGE established a reserve of \$10 million in 2005 related to the settlement. The settlement is subject to final approval by the Multnomah County Circuit Court following a hearing currently scheduled for late July 2006.

City of Portland Investigation

In September 2005, the Portland City Council approved a resolution directing the City Attorney and City staff to obtain from PGE information regarding the collection and payment of utility income taxes. The City has stated that it believes its City Charter provides it with authority for this request. PGE voluntarily provided extensive financial and operational data to the City. The City has since broadened its inquiry to include PGE's power trading activities in 2000 and 2001 and has requested that PGE provide many additional documents and records. PGE has determined that there are a number of legal and practical issues concerning the City's request for additional information, and has declined to provide any additional data to the City while those issues remain unresolved.

General Rate Case

On March 15, 2006, PGE filed new tariffs with the OPUC seeking a 1.7% average increase in electric rates related to general (non-power) costs, to be effective January 1, 2007. In addition, the filing includes a 2.9% average increase for recovery of PGE's investment in the Port Westward natural gas generating plant, effective on the date the plant begins commercial operation. The filing also contains an estimated rate adjustment related to PGE's RVM tariff (described below). Due largely to increases in the cost of natural gas and power purchases, PGE currently estimates an average 4.1% rate increase related to the RVM, to become effective on January 1, 2007. The RVM process requires that PGE update this estimate as the year progresses, with final forecasts due in early November 2006.

The filing proposes a return on common equity of 10.75% (based on an expected capital structure of approximately 56% equity and 44% debt) and an allowed rate of return of 8.97% on debt and equity capital. Proposed price increases are estimated to result in an approximate \$143 million increase in annual revenues.

In order to protect both PGE and its customers from power cost volatility and to allow customers a greater opportunity to share the benefits of any future savings in power costs, the Company is also proposing a tariff under which it would share with customers 90% of the difference between each year's forecast and actual net variable power costs. The annual update of prices to reflect changes in net variable power costs, as provided under the RVM, would continue.

Review of PGE's filing by the OPUC, including a detailed analysis of the Company's projected costs and proposed rate structure, is expected to take from nine to ten months and will include input from stakeholders and the public.

Resource Valuation Mechanism

The general rate order issued by the OPUC in 2001 approved an RVM tariff mechanism that requires annual updates of PGE's net variable power costs for inclusion in base rates for the following year. Developed in compliance with guidelines for Oregon's energy restructuring law that allow businesses direct access to energy service suppliers, the RVM utilizes a combination of market prices and the value of the Company's resources to establish power costs and set prices for energy services. It provides for an adjustment, finalized in mid-November each year, that is effective on January 1 of the following year.

Power Cost Price Decrease - 2003 PGE's first annual revision of its power supply costs under the RVM tariff forecasted a reduction in the cost of power from that included in the Company's 2001 general rate case. Accordingly, the OPUC authorized an approximate 7% average reduction in the Company's retail prices for 2003. Price decreases ranged from 2% for residential customers to between 9% and 17% for commercial and industrial customers, which were affected more by a reduction in wholesale energy market prices. These price decreases reduced PGE's 2003 revenues by approximately \$90 million.

Power Cost Price Increase - 2004 Based upon projections in PGE's 2004 RVM filing, the OPUC authorized an approximate 0.4% average retail price increase for 2004. Price adjustments ranged from a 2.3% decrease for large non-residential customers to increases of 2.8% and 1.9% for small non-residential and residential customers, respectively. Price adjustments varied between customer classes primarily because of different collection periods for a power cost adjustment mechanism that was in effect for the period 2001-2002. Such adjustments increased PGE's 2004 revenues by approximately \$4 million.

Power Cost Price Increase - 2005 Based upon projections in PGE's 2005 RVM filing, the OPUC authorized an approximate 1.4% average retail price increase for 2005. Price adjustments ranged from a 0.7% decrease for small non-residential customers to increases of 0.3% and 3.3% for residential and large non-residential customers, respectively. Such adjustments increased PGE's 2005 revenues by approximately \$17 million.

Power Cost Price Increase - 2006 Based upon projections in PGE's 2006 RVM filing, the OPUC authorized an approximate 3.7% average retail price increase for 2006, due largely to substantial increases in the cost of wholesale power and continued high prices for natural gas. Increases (including the effect of all credits and adjustments) range from 1.7% for residential customers to 5.3% and 5.4%, respectively, for small and large non-residential customers. Such adjustments are expected to increase PGE's 2006 revenues by approximately \$47 million.

Boardman Coal Plant - Extended Outage

On October 22, 2005, following the detection of vibrations in Boardman's steam turbine rotor, the plant was taken out of service. Following repeated unsuccessful efforts to return the plant to service, the rotor was removed and shipped to an east coast facility for repair. On February 6, 2006, during the process of returning the plant to operation, the generator rotor was damaged. The generator rotor has been removed for repairs. Although the actual time required to repair the generator rotor has not yet been determined, PGE estimates that Boardman will be operational by late April 2006. Due to the extended outage, annual maintenance requirements, originally scheduled for the second quarter of 2006, have been completed.

The extended outage has required that PGE replace its portion of Boardman's generation with both higher cost purchases in the wholesale market and increased generation from the Company's natural gas-fired generating plants. PGE's incremental power costs to replace its share of Boardman's generation in the fourth quarter of 2005 were estimated at \$41 million, with first quarter 2006 incremental power costs estimated at \$45 million. Estimated replacement power costs for April 2006 are expected to range from \$200,000 to \$300,000 per day. Incremental power costs related to the initial portion of the outage (October 23, 2005 through February 5, 2006) are estimated at \$64 million, with incremental power costs related to the outage from February 6, 2006 to the end of the first quarter of 2006 currently estimated at \$22 million.

On November 18, 2005, PGE filed with the OPUC an "Application for Deferred Accounting of Excess Power Costs Due to Plant Outage". The application requested an order authorizing PGE to defer for

later ratemaking treatment excess power costs associated with Boardman's turbine rotor outage, effective on the date of the application. The application seeks deferral of the difference between Boardman's variable power costs used in setting rates for 2005 and 2006 (under the Company's RVM) and replacement power costs incurred during the turbine rotor outage. The deferral period for the outage ended on February 5, 2006 with the installation of the repaired turbine rotor. The deferral amount is currently estimated at approximately \$45 million. No deferral was recorded in 2005. A procedural schedule has been adopted for further consideration of the deferral by the Commission. Management cannot predict the timing or the ultimate outcome of a decision by the OPUC on the Company's application. Under the RVM process, a 4-year rolling average of historical forced outages of PGE's generating plants is used in setting expected power costs. To the extent the Company is not allowed to recover replacement power costs for Boardman under the deferred accounting application, impacts of the turbine rotor forced outage (October 23, 2005 through February 5, 2006) may be included in the 4-year rolling average component of rates requested under the RVM process beginning in 2007.

PGE has determined that it will not file an application to defer incremental power costs related to the outage resulting from damage to the generator rotor, which began on February 6, 2006. The Company is evaluating, however, whether to propose including this outage in the 4-year rolling average of forced outages in its RVM filings starting in 2008.

Hydro Generation Adjustment

The effect of adverse hydro conditions in recent years has required that PGE acquire replacement power resources for shortfalls in hydro-based power, incurring substantially higher variable power costs than those included in the Company's electricity prices. In 2004, PGE requested OPUC consideration of a hydro generation adjustment tariff that would allow rate adjustment reflecting changes in power costs caused by variations in hydro conditions. The Company also filed an application to defer costs or benefits due to variances in hydro generation, beginning in 2005.

In 2005, PGE and OPUC Staff entered into stipulations for a mechanism that would defer for future recovery in rates a portion of power cost changes caused by variations in hydro conditions, power market prices, and natural gas prices during 2005 and 2006. Following hearings and consideration of the stipulations, the OPUC on December 21, 2005 issued an order that rejected the stipulations but left the dockets open and established criteria by which it would approve a hydro-related power cost adjustment mechanism. In February 2006, PGE withdrew its deferred accounting application and notified the OPUC that the Company will not pursue a hydro generation adjustment tariff, but has instead included a long-term general power cost adjustment mechanism in its current general rate case.

Port Westward Generating Plant

In February 2005, pursuant to PGE's strategy to meet the electric energy needs of its customers outlined in its Integrated Resource Final Action Plan, PGE began construction of Port Westward, a 400 MW natural gas-fired facility located in Clatskanie, Oregon. Construction is proceeding on schedule, with completion expected in the first quarter of 2007. Total cost of the plant is estimated between \$275 million and \$295 million (including AFDC).

Hydro Relicensing

The 30-year license for PGE's four hydro projects on the Clackamas River expires in August 2006. The Company filed an application with the FERC in 2004 to relicense the projects. A settlement agreement, resolving most of the issues raised in the relicensing proceeding and providing for a 45-year license term, was signed by the thirty-three participating parties on March 2, 2006 and will be submitted to the FERC for review and approval. Pending approval of the new license, the plants will

operate under annual licenses issued by the FERC. The agreement provides for improved fish and wildlife protection and recreational opportunities at the hydro facilities. It also provides for a collaborative process for the resolution of water temperature issues downstream of the project, which must be settled prior to the issuance of a new license. It is not certain when the FERC will issue a new license for the projects.

Mid-Columbia Hydro Matters

PGE's long-term power purchase contracts with certain public utility districts in the state of Washington expire between 2009 and 2018. PGE has executed new agreements with Grant County Public Utility District (Grant), operator of the Priest Rapids and Wanapum projects, for periods corresponding to Grant's new license term, to be determined by the FERC. The Priest Rapids agreement became effective in November 2005 and the Wanapum agreement will become effective November 1, 2009. Both contracts, which are subject to approval of the FERC, extend through the life of Grant's new license. Under the agreements, Grant will annually determine the output required for its purposes, with PGE required to purchase approximately 25% of the output in excess of Grant's requirements over the term of the new license, for which PGE will pay a proportional share of the project's debt service and operating costs. PGE's share in the projects will steadily decline as Grant's needs increase, with the Company's share in the two projects reduced from the current 189 MW to an estimated 151 MW in 2010. Also under the agreements, PGE will purchase an additional 49 average megawatts of power annually during the period 2006-2011.

In February 2005, the FERC approved a settlement between Douglas County PUD (Douglas), owner of the Wells Hydroelectric Project (Project), and the Colville Confederated Tribes (Colville Tribe) that resolved claims for charges for the use of Colville tribal lands. The settlement requires that Douglas pay a \$13.5 million lump sum, convey certain real property, and allocate (at cost) 4.5% of Project's output to the Colville Tribe; such allocation increases to 5.5% for all years after 2018. To fund the \$13.5 million payment, PGE and other purchasers of the Project's output entered into a Settlement Endorsement Agreement (Agreement) providing for the sale by Douglas of revenue bonds. The Agreement requires that each purchaser of the Project's output pay their respective share of debt service on the revenue bonds, with PGE's annual share calculated at approximately \$350,000. In addition to its share of debt service payments, PGE's share of the Project's output was reduced from 20.3% to 19.4% beginning in April 2005. The effects of both the debt service requirement and the reduction in output were included in projected power costs in PGE's final 2005 and 2006 RVM filings approved by the OPUC.

For further information regarding PGE's power purchase contracts from mid-Columbia projects, see Note 7, Commitments and Guarantee, in the Notes to Financial Statements.

Trojan Investment Recovery

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

Numerous challenges, appeals, and requested reviews were subsequently filed in the Marion County Circuit Court, the Oregon Court of Appeals, and the Oregon Supreme Court on the issue of the OPUC's authority under Oregon law to grant recovery of, and a return on, the Trojan investment. The Oregon Court of Appeals issued an opinion in 1998, stating that the OPUC does not have the authority

to allow PGE to recover a return on the Trojan investment, but upholding the OPUC's authorization of PGE's recovery of the Trojan investment and ordering remand of the case to the OPUC. PGE, the OPUC, and URP each requested the Oregon Supreme Court to conduct a review of the Court of Appeals decision. On November 19, 2002, the Oregon Supreme Court dismissed the petitions for review. As a result, the 1998 Oregon Court of Appeals opinion stands and the case has been remanded to the OPUC.

In 2000, while the petitions for review of the 1998 Court of Appeals decision were pending at the Oregon Supreme Court, PGE, CUB, and the staff of the OPUC entered into settlement agreements with respect to litigation over recovery of, and return on, the Trojan investment. The settlement agreements, approved by the OPUC in September 2000, allowed PGE to remove from its balance sheet the remaining before-tax investment in Trojan of approximately \$180 million at September 30, 2000, along with several largely offsetting regulatory liabilities. The URP filed a complaint with the OPUC challenging the settlement agreements and the OPUC's September 2000 order. In March 2002, the OPUC issued an order (2002 Order) denying all of URP's challenges and approving the accounting and rate making elements of the 2000 settlement. URP appealed the 2002 Order to the Marion County Circuit Court and on November 7, 2003, the Court issued an opinion remanding the case to the OPUC for action to reduce rates or order refunds. The opinion does not specify the amount or timeframe of any reductions or refunds. PGE and the OPUC have appealed to the Oregon Court of Appeals.

In a separate legal proceeding, two class action suits were filed in Marion County Circuit Court against PGE on January 17, 2003 on behalf of two classes of electric service customers. One case seeks to represent current PGE customers that were customers during the period from April 1, 1995 to October 1, 2001 (Current Class) and the other case seeks to represent PGE customers that were customers during the period from April 1, 1995 to October 1, 2001, but who are no longer customers (Former Class, together with the Current Class, the Class Action Plaintiffs). The suits seek damages of \$190 million for the Current Class and \$70 million for the Former Class, as a result of the inclusion of a return on investment of Trojan in the rates PGE charges its customers. On April 28, 2004, the plaintiffs (Class Action Plaintiffs) filed a Motion for Partial Summary Judgment and on July 30, 2004, PGE also moved for Summary Judgment in its favor on all of Class Action Plaintiffs' claims. On December 14, 2004, the Judge granted the Class Action Plaintiffs' motion for Class Certification and Partial Summary Judgment and denied PGE's motion for Summary Judgment. PGE filed a proposed order certifying the issue for an interlocutory appeal. An order rejecting the proposed order was entered on February 1, 2005. On March 3, 2005 and March 29, 2005, PGE filed two Petitions for an Alternative Writ of Mandamus with the Oregon Supreme Court asking the Court to take jurisdiction and command the trial Judge to dismiss the complaints or to show cause why they should not be dismissed and seeking to overturn the Class Certification. On May 3, 2005, the Oregon Supreme Court granted both Petitions. Briefing and arguments have been completed and a decision is pending.

On March 3, 2004, the OPUC re-opened three dockets in which it had addressed the issue of a return on PGE's investment in Trojan, including the 1995 Order and 2002 Order related to the settlement of 2000.

On August 31, 2004, the administrative law judge issued an Order (Scoping Order) defining the scope of the proceedings necessary to comply with the Marion County Circuit Court orders remanding this matter to the OPUC. On October 18, 2004, the OPUC affirmed the Scoping Order. On December 20, 2004, the URP and Class Action Plaintiffs filed an application with the OPUC for reconsideration of the Scoping Order. On February 11, 2005, the OPUC denied reconsideration and on April 18, 2005, URP and Linda K. Williams filed a complaint against the OPUC in Marion County Circuit Court challenging the OPUC's affirmation of the Scoping Order. The OPUC filed a motion to

dismiss the complaint, and on September 21, 2005, the Marion County Circuit Court granted the OPUC's motion. Hearings in the first phase of the OPUC proceeding have been held and a decision is pending.

Threatened Litigation - Class Action Lawsuit - On February 14, 2005, PGE received a Notice of Potential Class Action Lawsuit for Damages and Demand to Rectify Damages from counsel representing Frank Gearhart, David Kafoury and Kafoury Brothers, LLC (Potential Plaintiffs), stating that Potential Plaintiffs intend to bring a class action lawsuit against the Company. Potential Plaintiffs allege that for the period from October 1, 2000 to the present, PGE's electricity rates have included unlawful charges for a return on investment in Trojan in an amount in excess of \$100 million. Under Oregon law, there is no requirement as to the time the lawsuit must be filed following the 30-day notice period. No action has been filed to date.

Management cannot predict the ultimate outcome of the above challenges. However, it believes that the resolution will not have a material adverse impact on the financial condition of the Company, but may have a material impact on the results of operations and cash flows for a future reporting period. No reserves have been established by PGE for any amounts related to this issue.

Nuclear Decommissioning

PGE has completed all radiological decommissioning activities at Trojan and, upon approval of the NRC, the plant's operating license was terminated on May 23, 2005. Previously, the steam generator, reactor containment vessel, and other major components were removed and transported to a licensed low level radioactive waste disposal facility in Washington State for permanent storage. Spent nuclear fuel has been stored in the Independent Spent Fuel Storage Installation (ISFSI), an interim dry storage facility that houses the fuel at the plant site until permanent off-site storage is available. Spent fuel storage activities will continue to be subject to NRC regulation until all nuclear fuel is removed from the site, decontamination is completed, and the storage installation is fully decommissioned. Remaining decommissioning activities consist of demolition of the existing structures (including the plant's cooling tower and those buildings that once housed the plant's turbine, reactor, and spent fuel pool) and long-term operation and decommissioning of the ISFSI.

PGE has recorded an ARO for Trojan decommissioning of \$107 million, measured at estimated fair value, as of December 31, 2005. The ARO estimate assumes that the majority of decommissioning activities were completed at the end of 2005, with remaining costs extending through 2024. The plan anticipates final site restoration activities will begin in 2023 after PGE completes shipment of spent fuel to a USDOE facility. Decommissioning expenditures are estimated at \$11 million for 2006, compared to \$4 million in 2005.

In 2002, the USDOE formally recommended Yucca Mountain, Nevada as the nation's first long-term geologic (underground) repository for high-level radioactive waste produced in the United States. The proposed location is based on the conclusions of scientific studies of the site, conducted over 20 years, which support a finding of suitability as mandated by the Nuclear Waste Policy Act and various regulations of the NRC, USDOE, and the EPA. The House and Senate approved the site and in 2002, President Bush signed the Yucca Mountain resolution into law. Lawsuits have been filed objecting to the recommendation of Yucca Mountain as a nuclear waste repository. Based upon updated information received from the USDOE regarding the acceptance of spent nuclear fuel from Trojan, PGE has extended its projection for the final shipment of spent fuel from 2018 to 2023. The USDOE has not yet submitted to the NRC the required application for an operating license for the repository. Further delays may make it difficult for PGE to move its spent nuclear fuel, currently contained in the ISFSI, to permanent underground storage by 2023.

In 2004, the co-owners of Trojan (PGE, Eugene Water & Electric Board, and PacifiCorp) filed a complaint against the USDOE in the U.S. Court of Federal Claims for failure to accept spent nuclear fuel by January 31, 1998, as required by the Standard Form Contract. The plaintiffs paid for permanent disposal services during the period of plant operation (in the total amount of \$109 million) and have met all other conditions precedent. Damages sought are in excess of \$200 million.

The Energy Policy Act of 1992 provided for the creation of a Decontamination and Decommissioning Fund to finance the cleanup of USDOE gas diffusion plants, with funding provided by both domestic nuclear utilities and the federal government. Contributions are based upon each utility's share of total enrichment services purchased by all domestic utilities prior to enactment of the legislation. PGE's \$17 million share of the total funding requirement, based on Trojan's 1.1% usage of total industry enrichment services, is paid in annual installments that began in 1993, with the final payment due in late-2006.

In response to the terrorist attacks of September 11, 2001, the NRC issued interim compensatory security measures for a generalized high-level threat environment at closed nuclear reactors that are in the decommissioning process and at ISFSIs. The new requirements are expected to remain in effect until the NRC determines that the level of threat has diminished, or that other security changes are needed. The NRC issued additional security orders to all operating reactors in 2003 that require operating plants to update their defensive strategies to counter a highly organized attack. It is possible that corresponding similar orders (limited in scope) will eventually be issued to the Trojan ISFSI. Until NRC requirements associated with any new orders are determined, any implementation costs (including their impact on the Trojan decommissioning cost estimate and related funding requirements) are not determinable. However, as any new security requirements are evaluated, any additional costs will be determined and decommissioning cost estimates revised as necessary.

Receivables and Refunds on Wholesale Market Transactions

Receivables - California Wholesale Market

As of December 31, 2005, PGE has net accounts receivable balances totaling approximately \$63 million from the California ISO and the PX for wholesale electricity sales made from November 2000 through February 2001. The Company estimates that the majority of this amount was for sales by the ISO and PX to Southern California Edison Company and Pacific Gas & Electric Company (PG&E).

In March 2001, the PX filed for bankruptcy and in April 2001, PG&E filed a voluntary petition for relief under the provisions of Chapter 11 of the federal Bankruptcy Code. PGE filed a proof of claim in each of the proceedings for all past due amounts. Although both entities have emerged from their bankruptcy proceedings as reorganized debtors, not all claims filed in the proceedings, including those filed by PGE, have been resolved. PGE is continuing to pursue collection of these claims.

Management continues to assess PGE's exposure relative to these receivables. Based upon FERC orders regarding the methodology to be used to calculate refunds and the FERC's indication that potential refunds related to California wholesale sales (see "Refunds on Wholesale Transactions" below) can be offset with accounts receivable related to such sales, PGE has established reserves totaling \$40 million related to this receivable amount. The Company is examining numerous options, including legal, regulatory, and other means, to pursue collection of any amounts ultimately not received through the bankruptcy process.

Refunds on Wholesale Transactions

California - On July 25, 2001, the FERC issued an order establishing the scope of and methodology for calculating refunds for wholesale sales transactions made between October 2, 2000 and June 20, 2001 in the spot markets operated by the ISO and PX. The order established evidentiary hearings to develop a factual record to provide the basis for the refund calculation. Several additional orders clarifying and further defining the methodology have since been issued by the FERC. Appeals of the FERC orders were filed and in August 2002 the U.S. Ninth Circuit Court of Appeals issued an order requiring the FERC to reopen the record to allow the parties to present additional evidence of market manipulation.

Also in August 2002, the FERC Staff issued a report that included a recommendation that natural gas prices used in the methodology to calculate potential refunds be reduced significantly, which could result in a material increase in PGE's potential refund obligation.

In December 2002, a FERC administrative law judge issued a certification of facts to the FERC regarding the refunds, based on the methodology established in the 2001 FERC order rather than the August 2002 FERC Staff recommendation. On March 26, 2003, the FERC issued an order in the California refund case (Docket No. EL00-95) adopting in large part the certification of facts of the FERC administrative law judge but adopting the August 2002 FERC Staff recommendation on the methodology for the pricing of natural gas in calculating the amount of potential refunds. PGE estimates its potential liability under the modified methodology at between \$40 million and \$50 million, of which \$40 million has been established as a reserve, as discussed above.

Numerous parties, including PGE, filed requests for rehearing of various aspects of the March 26, 2003 order, including the methodology for the pricing of natural gas. On October 16, 2003, the FERC issued an order reaffirming, in large part, the modified methodology adopted in its March 26, 2003 order. PGE does not agree with the FERC's methodology for determining potential refunds and, on December 20, 2003, the Company appealed the FERC's October 16, 2003 order to the U.S. Ninth Circuit Court of Appeals; several other parties have also appealed the October 16, 2003 order. On May 12, 2004, the FERC issued an order that denied further requests for rehearing of the October 16, 2003 order. Although there continue to be miscellaneous orders issued in the underlying FERC proceeding, the Ninth Circuit Court of Appeals has now begun to hear the numerous appeals. It has bifurcated appeals of the existing cases into two phases. The first considered arguments regarding jurisdictional issues and the permissible scope of refund liability, both in terms of the time frame for which refunds were ordered and the types of transactions subject to refund. Briefing and oral argument have been completed on this first phase. As to the jurisdictional issues, on September 6, 2005, the Court ruled that FERC did not have jurisdiction to order municipal utilities and other governmental entities to make refunds for the sales they had made to the ISO and PX that are the subject of the refund proceeding. The Court has not yet issued a decision on the other issues pending in the first phase, and the Court agreed to defer the rehearing deadline on the jurisdictional issue decision until the remainder of the first phase is decided. The second phase will consider the issues relating to the refund methodology itself. PGE expects that the Court will establish additional phases as the continuing issues remaining before FERC become final and are appealed.

Also on May 12, 2004, the FERC issued a separate order that provided clarification regarding certain aspects of the methodology for California generators to recover fuel costs incurred to generate power that were in excess of the gas cost component used to establish the refund liability. On September 24, 2004, the FERC issued an order that denied requests for rehearing of its May 12, 2004 fuel cost order and also adopted a new methodology to allocate the excess amounts of fuel costs that

California generators are permitted to recover. Additional clarifying orders continue to be issued periodically. Under the new allocation methodology of the September 24, 2004 order, PGE could be required to pay additional amounts in those hours when it was a net buyer in California spot markets, thus increasing its net refund liability. PGE does not expect that this order will materially increase the Company's potential refund exposure. Partly as a means of limiting its exposure to additional fuel costs, PGE has opted to become a participant in several settlements filed jointly by large generators and California parties, and approved by the FERC during 2004 and 2005.

In August 2005, PGE joined in a settlement agreement resolving issues relating to the allocation of the wind-up costs of the PX for both past and future periods. The settlement has been approved by the FERC. Although under the agreement PGE will bear certain additional costs associated with PX obligations to conduct and finalize refund calculations, PGE does not expect those costs to be material to its financial statements.

In several of its underlying refund orders, the FERC has indicated that if marketers, such as PGE, believe that the level of their refund liability has caused them to incur an overall revenue shortfall for their sales to the ISO and PX during the refund period, they will be permitted to file a cost study to prove that they should be permitted to recover additional revenues in excess of the mitigated prices in order to cover their costs. By order issued August 8, 2005, FERC provided guidelines regarding the manner in which these studies should be conducted and the principles that should govern their preparation. PGE filed for rehearing of certain aspects of the August 8 order, and, on September 14, it filed its cost recovery study with FERC. The study showed that, pursuant to the principles set forth in the August 8 order and subject to rehearing, PGE's costs to serve the ISO and PX markets exceeded the revenues PGE will receive from those mitigated sales by over \$27 million. By order issued January 26, 2006, the FERC conditionally accepted PGE's September 14 cost filing, subject to PGE making a compliance filing to eliminate certain costs, to include additional revenues, and to supplement its analysis with additional cost, load, and resource data. On February 10, 2006, PGE submitted a compliance filing with two cases, in the alternative, that incorporated the FERC-required changes. The compliance filing shows a revenue deficit for PGE's sales to the ISO and PX (that is, a reduction to PGE's refund liability) of from approximately \$20 million to approximately \$30 million, depending on the methodology ultimately accepted by the Commission. Third parties have challenged PGE's compliance filing and requested that it be rejected in its entirety or that the cost offset be reduced to zero, and PGE has filed a response to those challenges. The procedure established by the FERC in the January 26 order also required each seller whose cost filing has been accepted to incorporate in its filing final ISO and PX settlement data and to provide its revised filing to the ISO and PX for further processing.

PGE believes that the FERC erred in certain of its findings in the January 26 order, and has filed a request for rehearing as to several issues. Due to the continuing uncertainty related to these matters, PGE has made no adjustment to the \$40 million reserve previously established for the Company's potential liability, as described above.

The FERC has indicated that any refunds PGE may be required to pay related to California wholesale sales (plus interest from collection date) can be offset by accounts receivable (plus interest from due date) related to sales in California (see "Receivables - California Wholesale Market" above). In addition, any refunds paid or received by PGE applicable to spot market electricity transactions on and after January 1, 2001 in California may be eligible for inclusion in the calculation of net variable power costs under the Company's power cost adjustment mechanism in effect at that time. This could further mitigate the financial effect of any refunds made or received by the Company.

Challenge of the California Attorney General to Market-Based Rates - On March 20, 2002, the California Attorney General filed a complaint with the FERC against various sellers in the wholesale power market, alleging that the FERC's authorization of market-based rates violated the Federal Power Act (FPA), and, even if market-based rates were valid under the FPA, that the quarterly transaction reports required to be filed by sellers, including PGE, did not contain the transaction-specific information mandated by the FPA and the FERC. The complaint argued that refunds for amounts charged between market-based rates and cost-based rates during the period October 2, 2000 - June 4, 2002 should be ordered. The FERC denied the challenge to market-based rates and refused to order refunds, but did require sellers, including PGE, to re-file their quarterly reports to include transaction-specific data. The California Attorney General appealed the FERC's decision to the Ninth Circuit Court of Appeals. On September 8, 2004, the Court issued an opinion upholding the FERC's authority to approve market-based tariffs, but also holding that the FERC had the authority to order refunds, if quarterly filing of market-based sales transactions had not been properly made. The Court required the FERC, upon remand, to reconsider whether refunds should be ordered. On October 25, 2004, certain parties filed a petition for rehearing with the Court. In the refund case and in related dockets, the California Attorney General and other California parties have argued that refunds should be ordered retroactively to at least May 1, 2000. Management cannot predict the outcome of these proceedings or whether the FERC will order refunds retroactively to May 1, 2000, and if so, how such refunds would be calculated.

Anomalous Bidding Allegations - By order issued on June 25, 2003, the FERC instituted an investigation into allegations of anomalous bidding activities and practices ("economic withholding") on the part of numerous parties, including PGE. The FERC determined that bids above \$250 per MW in the period from May 1, 2000 through October 2, 2000 may have violated tariff provisions of the ISO and the PX. The FERC required companies that bid in excess of \$250 per MW to provide information on their bids to the FERC investigation staff. PGE responded to the FERC's inquiries and, on May 12, 2004, the FERC investigation staff issued to PGE a letter terminating the investigation as to the Company without further action. On March 10, 2005, certain California parties filed appeals with the Ninth Circuit Court of Appeals, contesting the FERC's conduct of the investigation of the anomalous bidding allegations and the issuance of the dismissal letters.

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

Management cannot predict the ultimate outcome of the above matters related to wholesale transactions in California and the Pacific Northwest. However, it believes that the outcome will not have a material adverse impact on the financial condition of the Company, but may have a material impact on the results of operations for future reporting periods.

Union Grievances

In November 2001, grievances were filed by several members of the International Brotherhood of Electrical Workers Local 125 (IBEW), the bargaining unit representing PGE's union workers, alleging that losses in their pension/savings plan were caused by Enron's manipulation of its stock. The grievances, which do not specify an amount of claim, seek binding arbitration. PGE filed for relief in

Multnomah County Circuit Court seeking a ruling that the grievances are not subject to arbitration. On August 14, 2003, the Court granted PGE's motion for summary judgment, finding that the grievances are not subject to arbitration. A final judgment was entered on October 6, 2003. On October 22, 2003, the IBEW appealed the decision to the Oregon Court of Appeals. Both the U.S. District Court and the Bankruptcy Court approved the settlement of the class action litigation styled In re Enron Corp. Securities Derivative & "ERISA" Litigation, Pamela M. Tittle, et al, v. Enron Corp., et al, Civil Action No. H-01-3913, U.S. District Court for the Southern District of Texas, Houston Division (Tittle Action). On September 13, 2005, the U.S. District Court entered a Bar Order in the Tittle Action, which specifically bars all claims arising out of this case including the IBEW grievance proceeding. On October 18, 2005, at the request of the Oregon Court of Appeals, PGE filed a response memorandum in which PGE argued that the Bar Order makes the grievance moot. A decision is pending. Management cannot predict the ultimate outcome of this matter or estimate any potential loss.

Colstrip Plant - Royalty Claim

Western Energy Company (WECO) transports coal from the Rosebud Mine in Montana under a Coal Transportation Agreement with owners of Colstrip Units 3 and 4, in which PGE has a 20% ownership interest. In 2002 and 2003, WECO received two orders from the Office of Minerals Revenue Management of the U.S. Department of the Interior which asserted underpayment of royalties and taxes by WECO related to transportation of coal from the mine to Colstrip. WECO subsequently appealed the two orders to the Minerals Management Service (MMS) of the U.S. Department of the Interior. On March 28, 2005, the Appeals Division of the MMS denied in part, and granted in part, the appeals by WECO. On April 28, 2005, WECO appealed the decision of the MMS to the Interior Board of Land Appeals of the U.S. Department of the Interior. In May 2005, WECO received a "Preliminary Assessment Notice" from the Montana Department of Revenue, asserting claims similar to those of the Office of Minerals Revenue Management. No formal demand has been issued to date. Based upon review of the Coal Transportation Agreement, the Colstrip owners believe they have reasonable defenses against any claims for such royalties and taxes. PGE is monitoring these processes.

Environmental Matters

Harborton

A 1997 EPA investigation of a 5.5-mile segment of the Willamette River known as the Portland Harbor revealed significant contamination of sediments within the harbor. Based upon analytical results of the investigation, the EPA included the Portland Harbor on the federal National Priority List pursuant to the federal Comprehensive Environmental Response, Compensation, and Liability Act (Superfund).

In 1999, the DEQ asked that PGE perform a voluntary remedial investigation of its Harborton Substation site to confirm whether any hazardous substances had been released from the substation property into the Portland Harbor sediments. In May 2000, the Company entered into a "Voluntary Agreement for Remedial Investigation and Source Control Measures" (the Voluntary Agreement) with the DEQ, in which the Company agreed to complete a remedial investigation at the Harborton site under terms of the agreement.

In December 2000, PGE received from the EPA a "Notice of Potential Liability" regarding the Harborton Substation facility. The notice included a "Portland Harbor Initial General Notice List" containing sixty-eight other companies that the EPA believes may be Potentially Responsible Parties with respect to the Portland Harbor Superfund Site.

In March 2001, in accordance with the Voluntary Agreement, PGE submitted a final investigation plan to the DEQ for approval. DEQ approved the plan and in June 2001 PGE performed initial investigations and remedial activities based upon the approved investigation plan. The investigations have shown no significant soil or groundwater contaminations with a pathway to the river sediments from the Harborton site.

In February 2002, PGE submitted its final investigative report to the DEQ summarizing its investigations conducted in accordance with the May 2000 Voluntary Agreement. The report indicated that such voluntary investigation demonstrated that there is no likely present or past source or pathway for release of hazardous substances to surface water or sediments in the Portland Harbor Superfund Site at or from the Harborton Substation site. Further, the voluntary investigation demonstrated that the site does not present a high priority threat to present and future public health, safety, welfare, or the environment. The DEQ submitted the final investigative report to the EPA and in a May 18, 2004 letter, the EPA stated that "Based on the summary information provided by DEQ and the limited data EPA has at this stage in its process, EPA agrees at this time, that this site does not appear to be a current source of contamination to the river."

In a December 6, 2005 letter, the DEQ notified PGE that it is terminating the Voluntary Agreement, which is deemed to be satisfied. The DEQ further stated that "Based on our review of existing information and our understanding of current site conditions, DEQ determined that the site is not likely a current source of contamination to the river and that the site is a low priority for further action." Management believes that the Company's contribution to the sediment contamination, if any, from the Harborton Substation site would qualify it as a de minimis Potentially Responsible Party.

Sufficient information is currently not available to determine either the total cost of investigation and remediation of the Portland Harbor or the liability of Potentially Responsible Parties, including PGE. Management cannot predict the ultimate outcome of this matter. However, it believes this matter will not have a material adverse impact on its financial statements.

Harbor Oil

Harbor Oil, Inc. (Harbor Oil), located in north Portland, was utilized by PGE to process used oil from the Company's power plants and electrical distribution system from at least 1990 until 2003. Harbor Oil is also utilized by many other entities for the processing of used oil and other lubricants.

In 1974 and 1979, major oil spills occurred at the Harbor Oil site that impacted an approximate two acre area. Elevated levels of contaminants, including petroleum products, metals, pesticides, and polychlorinated biphenyl's (PCBs), have been detected at the site. On September 29, 2003, following investigation and site assessment by the EPA, Harbor Oil was included on the federal National Priority List as a federal Superfund site.

PGE received a Special Notice Letter for Remedial Investigation/Feasibility Study from the EPA, dated June 27, 2005, in which the Company was named as one of fourteen PRPs with respect to the Harbor Oil site. The letter starts a period for PRPs to participate in negotiations with the EPA to reach a settlement to conduct or finance a Remedial Investigation and Feasibility Study of the Harbor Oil site. Discussions among the EPA and the PRPs, including PGE, have commenced.

Sufficient information is currently not available to determine either the total cost of investigation and remediation of the Harbor Oil Site or the liability of PRPs, including PGE. Management cannot predict the ultimate outcome of this matter. However, it believes this matter will not have a material adverse impact on the Company's financial statements.

Other

In October 2003, PGE agreed with the DEQ to provide cost recovery for oversight of a voluntary investigation and/or potential cleanup of petroleum products at another Company site that is upland from the Portland Harbor Superfund Site. The site investigation has been completed and a report was submitted to the DEQ in August 2005. The report concludes that fuel and related contaminants have not migrated to the Willamette River from the site. The DEQ has stated that it is satisfied with the report. PGE management considers any material liability related to this matter to be remote.

Colstrip Plant

In December 2003, PPL Montana, LLC (PPL Montana), the operator of the Colstrip coal-fired generating plants, received an Administrative Compliance Order (ACO) from the EPA pursuant to the Clean Air Act (CAA). The EPA alleges that since 1980, Colstrip Units 3 and 4, in which PGE has a 20% ownership interest, have been in violation of the clean air permit issued under the CAA. The permit requires Colstrip Units 3 and 4 to submit, for review and approval by the EPA, an analysis and proposal for reducing nitrogen oxide emissions to address visibility concerns if and when the EPA establishes requirements for such emissions. The EPA asserts that regulations it established in 1980 triggered the requirement. PPL Montana is currently negotiating a consent decree with the EPA to resolve this matter, which would include penalties (if any) that may be assessed.

In addition to the ACO, the EPA has issued an information request with respect to the Colstrip units. The EPA is investigating whether older coal-fired plants have been modified over the years in a manner that would subject them to more stringent requirements under the CAA. Based on the settlement discussions with PPL Montana on the ACO, the EPA has indicated that it will not pursue this information request.

A local Native American tribe had asserted that sulfur dioxide emissions from Colstrip Units 3 and 4 are affecting local tribal areas more than previously estimated. PPL Montana has agreed to stricter sulfur dioxide emission limits in a recently approved Title V air permit for Colstrip, effectively resolving this matter.

New Accounting Standards

SFAS No. 123R (SFAS 123R), Share-Based Payment, was issued in December 2004 and replaces SFAS No. 123, Accounting for Stock-Based Compensation. Companies that issue share-based payment awards to employees are required to recognize compensation expense based on the fair value of the expected vested portion of the award as of the grant date over the vesting period of the award. Forfeitures that occur before the award vesting date will be adjusted from the total compensation expense, but once the award vests, no adjustment to compensation expense will be allowed for forfeitures or unexercised awards. In addition, SFAS 123R would require recognition of compensation expense of all existing outstanding awards that are not fully vested for their remaining vesting period as of the effective date that were not accounted for under a fair value method of accounting at the time of their award. SFAS 123R is effective for annual reporting periods beginning after June 15, 2005. PGE had no outstanding equity awards at December 31, 2005 and is evaluating the impact of the application of SFAS 123R and SEC Staff Accounting Bulletin No. 107 with respect to any future equity awards granted by the Company.

FASB Staff Position No. FAS 13-1 (FSP 13-1), Accounting for Rental Costs Incurred during a Construction Period, addresses the accounting for rental costs associated with ground and building operating leases that are incurred during a construction period. FSP 13-1 requires that rental costs associated with ground or building operating leases incurred during a construction period be recognized as rental expense and included in income from continuing operations. The application of FSP 13-1, which is required in the first reporting period beginning after December 15, 2005, is not expected to have a material effect on the financial statements of the Company.

Information Regarding Forward-Looking Statements

This report contains statements that are forward-looking within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements are statements of expectations, beliefs, plans, objectives, assumptions or future events or performance. Words or phrases such as "anticipates," "believes," "should," "estimates," "expects," "intends," "plans," "predicts," "projects," "will likely result," "will continue," or similar expressions identify forward-looking statements.

Forward-looking statements are not guarantees of future performance and involve risks and uncertainties that could cause actual results or outcomes to differ materially from those expressed. PGE's expectations, beliefs and projections are expressed in good faith and are believed by PGE to have a reasonable basis including, without limitation management's examination of historical operating trends, data contained in records and other data available from third parties, but there can be no assurance that PGE's expectations, beliefs or projections will be achieved or accomplished.

In addition to other factors and matters discussed elsewhere in this report, some important factors that could cause actual results or outcomes for PGE to differ materially from those discussed in forward-looking statements include:

- matters and events related to Enron and certain of its subsidiaries' bankruptcy proceedings under Chapter 11 of the federal Bankruptcy Code (PGE is not included in the filing);
- events related to the distribution of new PGE common stock to the Debtors' creditors who hold allowed claims and to the Disputed Claims Reserve;
- effects of electric industry restructuring in Oregon and in the United States, including retail and wholesale competition;
- governmental policies and regulatory investigations and actions, including those of the FERC and OPUC with respect to allowed rates of return, financings, electricity pricing and rate structures, acquisition and disposal of assets and facilities, operation and construction of plant facilities, recovery of net variable power costs and other capital investments, and present or prospective wholesale and retail competition;
- events related to the City of Portland, Oregon investigations with regard to rates charged by the Company, and any attempt by the City to set rates for PGE customers located within the City;
- matters regarding new Oregon law (including that related to utility rate treatment of income taxes), resulting in potential earnings volatility and adverse effects on operating results;
- changes in weather, hydroelectric, and energy market conditions, which could affect PGE's ability and cost to procure adequate supplies of fuel or purchased power to serve its customers;
- wholesale energy prices (including the effect of FERC price controls) and their effect on the availability and price of wholesale power purchases and sales in the western United States;

- the effectiveness of PGE's risk management policies and procedures and the creditworthiness of customers and counterparties;
- operational factors affecting PGE's power generation facilities;
- increasing national and international concerns regarding global warming and proposed regulations that could result in requirements for additional pollution control equipment or significant emissions fees or taxes, particularly with respect to coal-fired generation facilities, to mitigate carbon dioxide and other gas emissions;
- changes in, and compliance with, environmental and endangered species laws and policies;
- financial or regulatory accounting principles or policies imposed by governing bodies;
- residential, commercial, and industrial growth and demographic patterns in PGE's service territory;
- the loss of any significant customer, or changes in the business of a major customer, that may result in changes in demand for PGE services;
- the ability of PGE to access the capital markets to support requirements for working capital, construction costs, and the repayment of maturing debt;
- capital market conditions, including interest rate fluctuations and capital availability;
- changes in PGE's credit ratings, which could have an impact on the availability and cost of capital;
- legal and regulatory proceedings and issues;
- employee workforce factors, including strikes, work stoppages, and the loss of key executives;
- general political, economic, and financial market conditions; and,
- terrorist activities.

Any forward-looking statement speaks only as of the date on which such statement is made, and, except as required by law, PGE undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time and it is not possible for management to predict all such factors, nor can it assess the impact of any such factor on the business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

PGE is exposed to various forms of market risk (including changes in commodity prices, foreign currency exchange rates, and interest rates), as well as to credit risk. These changes may affect the Company's future financial results, as discussed below.

Commodity Price Risk

PGE's primary business is to provide electricity to its retail customers. The Company uses both long- and short-term purchased power contracts to supplement its thermal and hydroelectric generation to respond to fluctuations in the demand for electricity and variability in generating plant operations. In meeting these needs, PGE is exposed to market risk arising from the need to purchase power and to purchase fuel for its natural gas and coal fired generating units. The Company uses instruments such as forward contracts, which may involve physical delivery of an energy commodity, swap agreements, which may require payments to (or receipt of payments from) counterparties based on the differential between a fixed and variable price for the commodity, options, and futures contracts to mitigate risk that arises from market fluctuations of commodity prices.

Gains and losses from non-trading instruments that reduce commodity price risks are recognized when settled in Purchased Power and Fuel expense, or in wholesale revenue. Gains and losses on instruments used for trading purposes are recognized on a net basis within Operating Revenues on PGE's income statement. (Trading activities were discontinued in early 2005, with existing trading transactions settled by December 31, 2005). Valuation of these financial instruments reflects management's best estimates of market prices, including closing NYMEX and over-the-counter quotations, time value of money, and volatility factors underlying the commitments.

PGE actively manages its risk to ensure compliance with its risk management policies. The Company monitors open commodity positions in its energy portfolios using a value at risk methodology, which measures the potential losses in fair value due to the impact of market movements over a one-day holding period using a variance/covariance approach at a 95% confidence interval. The portfolio is modeled using net open power and natural gas positions, with power averaged over peak and off-peak periods by month, and includes all financial and physical positions for the next 24 months, including estimates of retail load and plant generation in the non-trading portfolio. The risk factors include commodity prices for power and natural gas at various locations and do not include volumetric variability. Based on this methodology, the average, high, and low value at risk on the non-trading portfolio in 2005 were \$3.8 million, \$9.7 million, and \$1.8 million, respectively, in 2004 were \$1.4 million, \$3.1 million, and \$0.6 million, respectively, and in 2003 were \$2.0 million, \$3.7 million, and \$1.0 million, respectively.

PGE's non-trading activities are subject to regulation. The timing differences between the recognition of gains and losses on certain derivative instruments and their realization and subsequent recovery in prices are deferred as regulatory assets and regulatory liabilities to reflect the effects of regulation under SFAS No. 71. As contracts are settled, these deferrals reverse. In its non-trading value at risk, PGE does not reflect any amount of these potential deferrals under SFAS No. 71.

Foreign Currency Exchange Rate Risk

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

Beginning in 2003, PGE implemented a strategy that utilizes forward contracts to acquire Canadian dollars in order to mitigate its currency exposure. At December 31, 2005, a 10% change in the value of the Canadian dollar would result in an immaterial change in pre-tax income for transactions that will settle over the next 12 months.

Interest Rate Risk

Although PGE had no short-term debt outstanding at December 31, 2005, the Company is typically exposed to risk resulting from changes in interest rates on variable rate short-term borrowings. The Company has also had exposure to interest rate changes on variable rate commercial paper. Although PGE currently has no financial instruments to mitigate such risk, it will consider such instruments in the future as necessary.

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

	Carrying Amounts by Maturity Date							
	Total Fair Value	Total	2006	2007	2008	2009	2010	After 2010
First Mortgage Bonds	\$ 558	\$520	\$ -	\$50	\$ -	\$ -	\$150	\$320
Pollution Control Revenue Bonds (*)	200	194	-	-	-	-	37	157
Other	192	176	11	17	-	-	148	-
Total	\$ 950	\$890	\$11	\$67	\$ -	\$ -	\$335	\$477

(*) Interest rates on \$142 million of Pollution Control Revenue Bonds are fixed until 2009. In 2009, pursuant to terms of the bond agreements, PGE will re-market the bonds and re-set the interest rate and maturity date up to the year 2033. A 1% increase in the current interest rates would result in an approximate \$1.4 million annual increase in interest expense.

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

Credit Risk

PGE is exposed to credit risk in its commodity price risk management activities related to potential nonperformance by counterparties. PGE manages the risk of counterparty default according to its credit policies by performing financial credit reviews, setting limits and monitoring exposures, and requiring collateral (in the form of cash, letters of credit, and guarantees) when needed. The Company also uses standardized enabling agreements and, in certain cases, master netting agreements, which allow for the netting of positive and negative exposures under the agreements associated with a counterparty. Despite such mitigation efforts, defaults by counterparties may periodically occur. Valuation allowances are provided for credit risk.

The large number and diversified base of residential, commercial, and industrial customers, combined with the Company's ability to discontinue service, contribute to reduced credit risk with respect to trade accounts receivable from retail electricity sales. Estimated provisions for uncollectible accounts

receivable related to retail electricity sales are provided for such risk. At December 31, 2005, the likelihood of significant losses associated with credit risk for trade accounts receivable is remote.

The following table presents PGE's credit exposure for commodity non-trading activities and their subsequent maturity as of December 31, 2005. The table reflects credit risk included in accounts receivable and price risk management assets, offset by related accounts payable and price risk management liabilities.

Non-Trading Activities

(Dollars in millions)				Maturity of Credit Risk Exposure					
Rating	Credit Risk Before Collateral	Percentage of Total Exposure	Credit Collateral	2006	2007	2008	2009	2010	After 2010
Investment Grade	\$ 238	95%	\$ 110	\$ 121	\$ 60	\$ 28	\$ 9	\$ 7	\$ 13
Non-Investment Grade	8	3%	8	8	-	-	-	-	-
Internally Rated - Investment Grade	<u>4</u>	<u>2%</u>	<u>-</u>	<u>4</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>
Total	\$ <u>250</u>	<u>100%</u>	\$ <u>118</u>	\$ <u>133</u>	\$ <u>60</u>	\$ <u>28</u>	\$ <u>9</u>	\$ <u>7</u>	\$ <u>13</u>

Investment Grade includes those counterparties with a minimum credit rating on senior unsecured debt of Baa3 (as assigned by Moody's) or BBB- (as assigned by S&P), and also those counterparties whose obligations are guaranteed or secured by an investment grade entity. Non-Investment Grade includes those counterparties with below investment grade credit ratings on senior unsecured debt. For non-rated counterparties, PGE performs credit analysis to determine an internal credit rating that approximates investment or non-investment grade. Included in this analysis is a review of counterparty financial statements, specific business environment, access to capital, and indicators from debt and capital markets. The credit exposure includes activity for electricity and natural gas forward, swap, and option contracts. Posted collateral may be in the form of cash or letters of credit and may represent prepayment or credit exposure assurance.

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

Risk Management Committee

PGE has a Risk Management Committee (RMC) which is responsible for providing oversight of the adequacy and effectiveness of the corporate policies, guidelines, and procedures for market and credit risk management related to the Company's energy portfolio management activities. The RMC, which provides quarterly reports to the Audit Committee of PGE's Board of Directors, consists of officers and Company representatives with responsibility for risk management, finance and accounting, legal, rates and regulatory affairs, power operations, and generation operations. The RMC reviews and recommends for adoption policies and procedures, establishes risk limits subject to PGE Board approval, and monitors compliance with policies, procedures, and limits on a regular basis through reports and meetings.

For further information on price risk management activities, see Note 8, Price Risk Management, in the Notes to Financial Statements.

Item 8. Financial Statements and Supplementary Data

Management's Responsibility for Financial Reporting

The following financial statements of Portland General Electric Company and its subsidiaries (collectively, PGE) were prepared by management, which is responsible for their integrity and objectivity. The statements have been prepared in conformity with accounting principles generally accepted in the United States of America and necessarily include some amounts that are based on the best estimates and judgments of management.

PGE maintains a system of internal control over financial reporting, which encompasses policies, procedures, and controls designed to provide reasonable assurance as to the reliability of the financial statements and for the protection of assets from unauthorized acquisition, use or disposition. This system is augmented by the careful selection and training of qualified personnel. It should be recognized, however, that there are inherent limitations in the effectiveness of any system of internal control. Accordingly, even an effective system of internal control over financial reporting can provide only reasonable assurance with respect to the preparation of reliable financial statements and safeguarding of assets. Further, because of changes in conditions, internal control system effectiveness may vary over time.

PGE also has disclosure controls and procedures that are designed to ensure that information required to be disclosed in reports filed under the Securities Exchange Act of 1934 (Exchange Act) is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Securities and Exchange Commission (SEC). The disclosure controls and procedures are also designed to ensure that information required to be disclosed is accumulated and communicated to PGE management, including its Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

The adequacy of PGE's internal controls, disclosure controls and procedures, and the accounting principles applied in financial reporting are under the general oversight of the Audit Committee of PGE's Board of Directors.

Report of Independent Registered Public Accounting Firm

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

We have audited the accompanying consolidated balance sheets of Portland General Electric Company and subsidiaries (the "Company") as of December 31, 2005 and 2004, and the related consolidated statements of income, retained earnings, comprehensive income, and cash flows for each of the three years in the period ended December 31, 2005. Our audits also included the financial statement schedule listed in Item 15 (a). These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Portland General Electric Company and subsidiaries as of December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

As discussed in Notes 1 and 11 to the consolidated financial statements, in 2003 the Company changed its method of accounting for asset retirement obligations and its presentation of operating revenues and operating expenses associated with non-trading electric derivative activities.

As discussed in Note 16 to the consolidated financial statements, the accompanying 2004 and 2003 financial statements have been restated.

Deloitte & Touche LLP
Portland, Oregon
March 14, 2006

Portland General Electric Company and Subsidiaries
Consolidated Statements of Income

For the Years Ended December 31	2005	2004	2003 (As Restated - See Note 16)
	(In Millions)		
Operating Revenues	\$1,446	\$1,454	\$1,752
Operating Expenses			
Purchased power and fuel	671	667	1,028
Production and distribution	128	127	117
Administrative and other	168	148	148
Depreciation and amortization	233	233	213
Taxes other than income taxes	74	72	72
Income taxes	46	57	50
	<u>1,320</u>	<u>1,304</u>	<u>1,628</u>
Net Operating Income	<u>126</u>	<u>150</u>	<u>124</u>
Other Income (Deductions)			
Miscellaneous	3	8	5
Income taxes	3	3	6
	<u>6</u>	<u>11</u>	<u>11</u>
Interest Charges			
Interest on long-term debt and other	<u>68</u>	<u>69</u>	<u>79</u>
Net Income before cumulative effect of a change in accounting principle	64	92	56
Cumulative effect of a change in accounting principle, net of related taxes of \$(3)	<u>-</u>	<u>-</u>	<u>4</u>
Net Income	64	92	60
Preferred Dividend Requirement	<u>-</u>	<u>-</u>	<u>1</u>
Income Available for Common Stock	<u>\$ 64</u>	<u>\$ 92</u>	<u>\$ 59</u>

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

Portland General Electric Company and Subsidiaries
Consolidated Statements of Retained Earnings

For the Years Ended December 31	2005	2004	2003
	(In Millions)		
Balance at Beginning of Year (restated, see Note 16)	\$ 644	\$ 552	\$ 493
Net Income (restated, see Note 16)	64	92	60
	<u>708</u>	<u>644</u>	<u>553</u>
Dividends Declared			
Common stock	150	-	-
Preferred stock	-	-	1
	<u>150</u>	<u>-</u>	<u>1</u>
Balance at End of Year	<u>\$ 558</u>	<u>\$ 644</u>	<u>\$ 552</u>

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

Portland General Electric Company and Subsidiaries
Consolidated Statements of Comprehensive Income

For the Years Ended December 31	2005	2004	2003 (As Restated - See Note 16)
	(In Millions)		
Accumulated other comprehensive income (loss) - Beginning of Year			
Unrealized gain (loss) on derivatives classified as cash flow hedges	\$ (2)	\$ 2	\$ 3
Minimum pension liability adjustment	(4)	(4)	(3)
Total	<u>\$ (6)</u>	<u>\$ (2)</u>	<u>\$ -</u>
Net Income	\$ 64	\$ 92	\$ 60
Other comprehensive income, net of tax:			
Unrealized gains (losses) on derivatives classified as cash flow hedges:			
Other unrealized holding gains arising during the period, net of related taxes of \$(18) in 2005, \$(8) in 2004, and \$(5) in 2003	28	12	9
Reclassification adjustment for contract settlements included in net income, net of related taxes of \$(3) in 2005, \$4 in 2004, and \$1 in 2003	4	(6)	(3)
Reclassification adjustment in net income due to discontinuance of cash flow hedges, net of related taxes of \$1 in 2005 and \$6 in 2003	(1)	-	(9)
Reclassification of unrealized gains (losses) to SFAS No. 71 regulatory (liability) asset, net of related taxes of \$19 in 2005, \$6 in 2004, and \$(2) in 2003	<u>(29)</u>	<u>(10)</u>	<u>2</u>
Total - Unrealized gains (losses) on derivatives classified as cash flow hedges	<u>2</u>	<u>(4)</u>	<u>(1)</u>
Minimum pension liability adjustment	<u>1</u>	<u>-</u>	<u>(1)</u>
Total Other comprehensive income (loss)	<u>3</u>	<u>(4)</u>	<u>(2)</u>
Comprehensive income	<u>\$ 67</u>	<u>\$ 88</u>	<u>\$ 58</u>
Accumulated other comprehensive income (loss) - End of Year			
Unrealized gain (loss) on derivatives classified as cash flow hedges	\$ -	\$ (2)	\$ 2
Minimum pension liability adjustment	(3)	(4)	(4)
Total	<u>\$ (3)</u>	<u>\$ (6)</u>	<u>\$ (2)</u>

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

Portland General Electric Company and Subsidiaries
Consolidated Balance Sheets

At December 31	2005	2004 (As Restated - See Note 16)
	(In Millions)	
<u>Assets</u>		
Electric Utility Plant - Original Cost		
Utility plant (includes construction work in progress of \$177 and \$114)	\$ 4,224	\$ 3,992
Accumulated depreciation	(1,788)	(1,717)
	<u>2,436</u>	<u>2,275</u>
Other Property and Investments		
Nuclear decommissioning trust, at market value	31	22
Non-qualified benefit plan trust	69	64
Miscellaneous	34	30
	<u>134</u>	<u>116</u>
Current Assets		
Cash and cash equivalents	122	204
Accounts and notes receivable (less allowance for uncollectible accounts of \$50 and \$50)	203	170
Unbilled revenues	78	80
Assets from price risk management activities	259	77
Inventories, at average cost	54	48
Prepayments and other	24	35
	<u>740</u>	<u>614</u>
Deferred Charges and Other		
Regulatory assets	217	295
Miscellaneous	111	103
	<u>328</u>	<u>398</u>
	<u>\$ 3,638</u>	<u>\$ 3,403</u>
<u>Capitalization and Liabilities</u>		
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	482	481
Retained earnings	558	644
Accumulated other comprehensive income (loss):		
Unrealized gain (loss) on derivatives classified as cash flow hedges	-	(2)
Minimum pension liability adjustment	(3)	(4)
Limited voting junior preferred stock	-	-
Long-term debt	879	892
	<u>2,076</u>	<u>2,171</u>
Commitments and Contingencies (see Notes)		
Current Liabilities		
Long-term debt due within one year	11	30
Accounts payable and other accruals	260	173
Liabilities from price risk management activities	129	38
Customer deposits	53	18
Accrued interest	17	19
Accrued taxes	42	37
Deferred income taxes	51	15
	<u>563</u>	<u>330</u>
Other		
Deferred income taxes	218	313
Deferred investment tax credits	10	13
Trojan asset retirement obligation	107	96
Accumulated asset retirement obligation	27	24
Regulatory liabilities:		
Accumulated asset retirement removal costs	349	286
Other	175	74
Non-qualified benefit plan liabilities	79	70
Miscellaneous	34	26
	<u>999</u>	<u>902</u>
	<u>\$ 3,638</u>	<u>\$ 3,403</u>

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	2005	2004	2003 (As Restated - See Note 16)
	(In Millions)		
Cash Flows From Operating Activities:			
Reconciliation of net income to net cash provided by operating activities			
Net income	\$ 64	\$ 92	\$ 60
Non-cash items included in net income:			
Cumulative effect of a change in accounting principle, net of tax	-	-	(4)
Depreciation and amortization	233	233	213
Deferred income taxes	(53)	(13)	(22)
Net assets from price risk management activities	(40)	(7)	(30)
Power cost adjustment	18	40	51
Other non-cash income and expenses (net)	44	16	19
Changes in working capital:			
Net margin deposit activity	35	13	-
(Increase) Decrease in receivables	(29)	43	9
Increase (Decrease) in payables	82	(61)	21
Other working capital items - net	4	(22)	(6)
Other - net	14	6	(4)
Net Cash Provided by Operating Activities	<u>372</u>	<u>340</u>	<u>307</u>
Cash Flows From Investing Activities:			
Capital expenditures	(255)	(194)	(167)
Purchases of nuclear decommissioning trust securities	(34)	(31)	(30)
Sales of nuclear decommissioning trust securities	21	32	28
Other - net	(4)	9	(9)
Net Cash Used in Investing Activities	<u>(272)</u>	<u>(184)</u>	<u>(178)</u>
Cash Flows From Financing Activities:			
Repayment of long-term debt	(32)	(61)	(402)
Issuance of long-term debt	-	-	342
Debt issue costs	-	-	(7)
Preferred stock retired	-	-	(3)
Dividends paid	(150)	-	(1)
Net Cash Used in Financing Activities	<u>(182)</u>	<u>(61)</u>	<u>(71)</u>
Increase (Decrease) in Cash and Cash Equivalents	(82)	95	58
Cash and Cash Equivalents, Beginning of Period	204	109	51
Cash and Cash Equivalents, End of Period	<u>\$ 122</u>	<u>\$ 204</u>	<u>\$ 109</u>
Supplemental disclosures of cash flow information			
Cash paid during the period:			
Interest, net of amounts capitalized	\$ 58	\$ 62	\$ 67
Income taxes	88	83	39
Non-cash investing and operating activities:			
Accrued capital additions	9	9	8

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

Portland General Electric Company and Subsidiaries

Notes to the Consolidated Financial Statements

Nature of Operations

PGE is a single, integrated electric utility engaged in the generation, purchase, transmission, distribution, and retail sale of electricity in the State of Oregon. The Company also sells wholesale electric energy to utilities, brokers, and power marketers located throughout the western United States. PGE operates as a single segment, with revenues and costs related to its business activities maintained and analyzed on a total electric operations basis. PGE's service area is located entirely within Oregon and includes 52 incorporated cities, of which Portland and Salem are the largest, within a state-approved service area allocation of approximately 4,000 square miles. At the end of 2005, PGE's service area population was approximately 1.5 million, comprising about 43% of the state's population. The Company served approximately 780,000 retail customers at December 31, 2005.

On July 2, 1997, Portland General Corporation (PGC), the former parent of PGE, merged with Enron Corp., with Enron Corp. continuing in existence as the surviving corporation. On December 2, 2001, Enron Corp., along with certain of its subsidiaries, filed to initiate bankruptcy proceedings under Chapter 11 of the federal Bankruptcy Code. PGE was not included in the filing, but the common stock of PGE is one of the assets of the bankruptcy estate. On November 17, 2004, the Fifth Amended Joint Plan of Affiliated Debtors Pursuant to Chapter 11 of the United States Bankruptcy Code, dated January 9, 2004 and as thereafter amended and supplemented from time to time (Chapter 11 Plan), became effective. PGE is currently a wholly-owned subsidiary of reorganized Enron Corp. (Enron).

In accordance with the Chapter 11 Plan, Enron plans to distribute PGE common stock to the creditors of Enron and its reorganized debtor subsidiaries (jointly the Debtors) holding allowed claims. Current PGE common stock will be cancelled and 62,500,000 shares of new PGE common stock without par value will be distributed over time to Debtors' creditors holding allowed claims. Initially, at least 30 percent of the new PGE common stock will be issued by PGE to the Debtors' creditors that hold allowed claims, with the remainder issued to a Disputed Claims Reserve (DCR), where it will be held to be released over time to the Debtors' creditors holding allowed claims, in accordance with the Chapter 11 Plan. Following the issuance of the new PGE common stock (currently expected to take place on or about April 3, 2006), PGE will no longer be a subsidiary of Enron. Distribution of new PGE common stock has been approved by the required regulatory agencies, including the OPUC and the FERC. However, the City of Portland has appealed the OPUC decision and the Utility Reform Project has filed for reconsideration by the OPUC. See Note 15, Future Ownership of PGE, for further information.

Note 1 - Summary of Significant Accounting Policies

Consolidation Principles

The consolidated financial statements include the accounts of PGE and its majority-owned subsidiaries, including variable interest entities when it is the primary beneficiary with a controlling financial interest. The Company's ownership share of direct expenses and plant costs related to jointly owned generating plants are also included in the consolidated financial statements. Intercompany balances and transactions have been eliminated.

Basis of Accounting

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

Use of Estimates

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

Contingencies

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

Reclassifications

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

Revenues

Retail revenues are recognized when monthly billings are made for energy sold to customers and delivered to those customers that purchase their energy from Energy Service Suppliers (ESSs). In addition, estimated unbilled revenues are accrued for services provided to retail customers from the meter read date to month-end. Unbilled revenues are calculated based upon each month's actual net system load, the number of days from meter-reading date to month-end, and current retail customer prices. Estimated provisions for uncollectible accounts receivable related to retail electricity sales, charged to Administrative and other expense, are recorded in the same period as the related revenues, with an offsetting credit to the allowance for uncollectible accounts. Such estimates are based on management's assessment of the probable collection of customer accounts, aging of accounts receivable, bad debt write-offs, actual customer billings, and other factors.

Wholesale revenues are recognized as energy is delivered to the Company's wholesale customers (primarily utilities and power marketers) during the month. Provisions related to wholesale accounts receivable and unsettled positions, charged to Purchased Power and Fuel expense, are based on a periodic review and evaluation that includes liquidity risk, counterparty non-performance risk, and contractual rights of offset when applicable. Actual amounts written off are charged to the allowance for uncollectible accounts.

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

Purchased Power

In addition to power purchases and certain price risk management activities (described under "Price Risk Management" in this Note), certain other activities are reflected in Purchased Power and Fuel expense. These consist of: 1) Amounts deferred under the Company's power cost adjustment mechanisms (described under "Power cost adjustment mechanisms" under "Regulatory Assets and Liabilities" in this Note), as well as amortization of such amounts as recovery is made from customers;

2) Amounts recorded under PGE's long-term power exchange contracts that help meet seasonal peaking requirements (for further information, see "Purchased Power" in Note 7, Commitments and Guarantee); and, 3) Provisions related to wholesale accounts receivable and unsettled positions (described under "Revenues" in this Note).

Price Risk Management

PGE engages in price risk management activities in its electric business, utilizing derivative instruments such as electricity forward, swap, and option contracts and natural gas forward, swap, option, and futures contracts. Under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (as amended), derivative instruments are recorded on the balance sheet as Assets and Liabilities from Price Risk Management Activities measured at fair value, unless they qualify for the normal purchases and normal sales exception, with changes in fair value recognized currently in earnings unless hedge accounting applies.

Non-Trading

Certain non-trading electricity forward contracts that are entered into in anticipation of serving the Company's regulated retail load meet the requirements for treatment under the normal purchases and normal sales exception under SFAS No. 133, as amended by SFAS No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities. Other non-trading activities consist of certain electricity forwards and natural gas forwards and swaps that qualify as cash flow hedges of forecasted transactions, and electricity options, certain electricity forwards, certain natural gas swaps and forward contracts for acquiring Canadian dollars that are classified as non-hedges. Such activities are utilized to protect against variability in expected future cash flows due to associated price risk and to minimize net power costs for retail customers.

The OPUC, which regulates PGE's retail electricity business, recognizes non-trading contracts only at the time of settlement. Contracts that qualify for the normal purchases and normal sales exception are not required to be recorded at fair value. Unrealized gains and losses from contracts that qualify as cash flow hedges are recorded net in OCI and contracts designated as non-hedges are recorded net in Purchased Power and Fuel expense on the Statement of Income. To reflect the effect of regulation, PGE records a regulatory asset or regulatory liability under SFAS No. 71 to offset unrealized gains and losses on certain non-trading contracts recorded prior to settlement to the extent that such changes are included in the Company's Resource Valuation Mechanism (RVM). The regulatory asset or regulatory liability is reflected within Regulatory assets or Regulatory liabilities, respectively, on the Balance Sheet. Upon settlement, the regulatory asset or regulatory liability is reversed.

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

Trading

PGE discontinued its energy trading activities for non-retail purposes in early 2005, with remaining transactions settled by December 31, 2005. Realized and unrealized gains and losses associated with such activities are reported on a net basis for all periods presented in accordance with EITF 02-3, Accounting for Contracts Involved in Energy Trading and Risk Management Activities, and are included within Operating Revenues on the Statement of Income.

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

Customer Deposits

In the course of its wholesale activities, PGE both receives and deposits performance assurance cash collateral, with required amounts based upon provisions contained in certain wholesale power agreements with counterparties. Amounts deposited with, or received from, counterparties under such agreements are reflected as Margin deposits and Customer deposits, respectively, within the Current Assets and Current Liabilities sections of the Balance Sheet. Also included within Current Liabilities are credit deposits received from certain retail and transmission customers.

Capitalization of Property, Plant and Equipment

Additions to utility plant are capitalized at their original cost, consistent with accounting and regulatory guidelines. Costs include direct labor, materials and supplies, and contractor costs, as well as indirect costs such as engineering, supervision, employee benefits, and allowance for funds used during construction. Plant replacements are capitalized, with minor items charged to expense as incurred. The costs to purchase/develop software applications are capitalized in accordance with AICPA Statement of Position 98-1, Accounting for the Costs of Computer Software Developed or Obtained for Internal Use. Costs of relicensing the Company's hydroelectric projects are capitalized and amortized over the related license period. For information regarding accounting for asset retirement obligations, see "Asset retirement obligations" and "Accumulated asset retirement removal costs" under "Regulatory Assets and Liabilities" in this Note.

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

	<u>2005</u>	<u>2004</u>
Production	\$1,395	\$1,376
Transmission	283	283
Distribution	1,954	1,856
General	239	243
Intangible	176	120
Construction Work in Progress	177	114
Total	<u>\$4,224</u>	<u>\$3,992</u>

Depreciation and Amortization of Property, Plant and Equipment

Depreciation is computed using the straight-line method over the estimated average service lives of various classes of plant in service. Classes of plant in service and their estimated service lives (in years) are as follows: Production (32), Transmission (55), Distribution (35), and General (13). Depreciation is based upon original cost and includes an estimate for cost of removal and expected salvage. Depreciation expense as a percent of the related average depreciable plant in service was approximately 4.4% in 2005, 4.5% in 2004, and 4.6% in 2003. Estimated asset retirement removal costs included in depreciation expense were \$64 million, \$61 million, and \$58 million in 2005, 2004, and 2003, respectively.

Periodic studies are conducted to update depreciation parameters (i.e. retirement dispersion patterns, average service lives, and net salvage rates), including estimates of Asset Retirement Obligations (AROs) and asset retirement removal costs. The studies are conducted every five years and are filed with the OPUC for approval and inclusion in a future rate proceeding. The most recent study, which is included in PGE's pending general rate case filing, was filed with the OPUC in October 2005.

The original cost of depreciable property units, net of any related salvage value, is charged to accumulated depreciation when property is retired and removed from service. Cost of removal expenditures are charged to asset retirement obligations for assets with AROs and to accumulated asset retirement removal costs for assets without AROs. See Note 11, Asset Retirement Obligations, for further information.

Intangible plant, consisting primarily of computer software development and hydro re-licensing costs, is amortized over estimated average service lives or the applicable license term. Amortization expense for 2005, 2004, and 2003 was \$13 million, \$14 million, and \$13 million, respectively, and is estimated at \$15 million for 2006, \$14 million for 2007, \$11 million for 2008, and \$10 million for both 2009 and 2010. Accumulated amortization was \$76 million and \$67 million at December 31, 2005 and December 31, 2004, respectively; the increase consists of the net amount of current year amortization expense less accumulated amortization on intangible plant retirements.

Major Maintenance Expenses

Costs of periodic major maintenance inspections and overhauls at the Company's generating plants are charged to operating expenses as incurred.

Allocations and Loadings

PGE utilizes a series of cost distributions and loadings to allocate certain administrative and overhead costs between capital and operating accounts, based primarily on construction activities of the Company.

Allowance for Funds Used During Construction (AFDC)

AFDC represents the pre-tax cost of borrowed funds used for construction purposes and a reasonable rate for equity funds. It is capitalized as part of the cost of plant and is credited to income but does not represent current cash earnings. The average rates used by PGE in 2005, 2004, and 2003 were 9.0%. AFDC from borrowed funds was \$4 million in 2005, and \$3 million in 2004 and 2003. AFDC from equity funds was \$8 million in 2005, \$6 million in 2004, and \$4 million in 2003.

Debt Issuance Costs

Underwriting, legal, and other direct costs related to the issuance of debt securities are deferred and amortized to interest expense equitably over the life of the security. Unamortized debt issuance costs at December 31, 2005 and 2004 were \$16 million and \$19 million, respectively, and are classified within Deferred charges - Miscellaneous on the Balance Sheet.

Income Taxes

PGE's federal taxable income was included in Enron's consolidated federal income tax return from July 2, 1997, the date of the Company's merger with Enron, until May 7, 2001, when Enron determined that PGE would no longer be a member of the Enron consolidated federal income tax return. During this time, PGE paid Enron for net tax liabilities generated on the taxable income of PGE, less applicable tax credits. Beginning May 8, 2001, PGE and its subsidiaries filed their own consolidated federal tax return and paid their own tax liabilities directly to the Internal Revenue Service (IRS). PGE and its subsidiaries also filed unitary state income tax returns, and paid their own state tax liabilities, in accordance with the applicable state law; they were also included in some Enron and subsidiaries' unitary state income tax returns. On December 24, 2002, PGE and its subsidiaries again became a member of Enron's consolidated tax group. Upon the issuance of new PGE common stock (currently expected to take place on or about April 3, 2006), PGE and its subsidiaries will no longer be a member of Enron's consolidated return and will file their own consolidated tax returns and remit tax payments directly to taxing authorities. For further information, see Note 13, Related Party Transactions, and Note 15, Future Ownership of PGE.

Deferred income taxes are provided for temporary differences between financial and income tax reporting. Investment tax credits utilized have been deferred and are amortized to income over the approximate lives of the related properties, not to exceed 25 years. See Note 3, Income Taxes, for further information.

Cash and Cash Equivalents

Highly liquid investments with maturities of three months or less at the date of acquisition are classified as cash equivalents.

Non-Qualified Benefit Plan Trust

The non-qualified benefit plan trust (rabbi trust) is comprised of insurance contracts and investments in money market, bond, and equity mutual funds. The cash surrender value of insurance contracts is reported as an asset at the end of the reporting period, with changes in such values between reporting periods recognized as income or expense of the period (see "Other Non-Qualified Benefit Plans" in Note 2, Employee Benefits, for further information). The cash surrender value of insurance contracts, the majority of which are held in the trust, was \$22 million at December 31, 2005 and \$20 million at December 31, 2004. The investments in marketable securities are classified as trading and recorded at fair value on the Balance Sheet. Realized and unrealized gains and losses on these investments (determined using average cost) are included in Other Income (Deductions) on the Statement of Income. Investments in marketable securities and cash totaled \$47 million at December 31, 2005 and \$44 million at December 31, 2004.

Inventories

PGE's inventories are recorded at cost, which includes the purchase price (less discounts), applicable taxes, transportation and handling, etc. The average cost method is utilized to price inventory as fuel is burned at the generating plants and as materials and supplies are issued for operations, maintenance and capital activities. General storeroom operation costs, including procurement, management, and storage, are recorded in the unallocated stores account and distributed equitably as materials and supplies are issued.

Inventories at December 31 are summarized as follows (in millions):

	<u>2005</u>	<u>2004</u>
Coal	\$ 11	\$ 8
Fuel oil	11	11
Natural gas	4	3
Materials and supplies	25	24
Unallocated stores account	3	2
Total	<u>\$ 54</u>	<u>\$ 48</u>

Trojan Decommissioning Costs

Trojan decommissioning costs consist of those expenditures related to the decommissioning of the Trojan Nuclear Plant. The present value of estimated future decommissioning expenditures, which is revised periodically, is recorded as an ARO on the Balance Sheet, with actual expenditures charged to the ARO account as incurred. See Note 11, Asset Retirement Obligations, and Note 12, Trojan Nuclear Plant, for further information.

Regulatory Assets and Liabilities

PGE is subject to the provisions of SFAS No. 71. Accounting under SFAS No. 71 is appropriate as long as rates are established by or subject to approval by independent third-party regulators; rates are designed to recover the specific enterprise's cost of service; and in view of demand for service, it is reasonable to assume that rates set at levels that will recover costs can be charged to and collected from customers.

When the requirements of SFAS No. 71 are met at the date the costs are incurred, or at a later date when evidence supports cost deferral (e.g. an OPUC deferred accounting order), the Company defers certain costs which would otherwise be charged to expense if it is probable that future prices will permit recovery of such costs. In addition, PGE defers certain revenues, gains, or cost reductions which would normally be reflected in income but through the rate making process will ultimately be refunded to customers. Regulatory assets and liabilities are reflected within Deferred Charges and Other on the Balance Sheet and are amortized over the period in which they are included in billings to customers. If at some point in the future PGE determines that all or a portion of the utility operations no longer meets the criteria for continued application of SFAS No. 71, PGE could be required to write-off its regulatory assets.

Unless otherwise noted, a return on the unamortized balance is recorded for regulatory assets and regulatory liabilities at PGE's authorized cost of capital of 9.083%.

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

	<u>2005</u>	<u>2004</u>
Regulatory assets:		
Trojan decommissioning costs	\$ 75	\$ 74
Income taxes recoverable	80	92
Prior tax benefits recoverable	1	10
Debt reacquisition costs	21	23
Conservation investments - secured	9	19
Energy efficiency programs	-	10
Power cost adjustment mechanism	-	19
Regulatory restructuring costs	16	20
Beaver 8	9	11
Pelton Round Butte tax benefits recoverable	-	3
Miscellaneous	6	14
Total	<u>\$217</u>	<u>\$295</u>
Regulatory liabilities:		
Asset retirement obligations	\$ 21	\$ 18
Accumulated asset retirement removal costs	349	286
Price risk management	130	45
Information technology costs	3	3
Trojan ISFSI pollution control tax credits	5	2
Oregon corporation excise tax refund	4	-
Miscellaneous	12	6
Total	<u>\$524</u>	<u>\$360</u>

Trojan decommissioning costs - PGE's current retail prices include recovery of \$14 million annually through 2011 for costs to decommission Trojan (see Note 12, Trojan Nuclear Plant, for further information). These amounts represent the estimated fair value of the remaining regulatory asset to be recovered from customers.

Income taxes recoverable - The amount represents tax benefits previously flowed to customers through rates for temporary differences between book and tax reporting. The balance is reduced as temporary differences reverse and the increase in current tax expense is recovered in customer rates.

Prior tax benefits recoverable - In 2000, PGE entered into settlement agreements related to the recovery of its investment in the Trojan plant. The agreements provided for removal from the Company's Balance Sheet of the remaining before-tax investment in Trojan, along with several largely offsetting regulatory liabilities. The settlement also allowed recovery of approximately \$47 million in income taxes related to the Trojan investment which had been flowed to customers in prior years; such amount is being recovered from PGE customers, with no return on the unamortized balance, over an approximate five-year period. See Note 10, Legal and Environmental Matters, for further information.

Debt reacquisition costs - As authorized by the OPUC, costs related to the reacquisition of debt securities, including unamortized debt issuance costs related to such debt securities, are deferred and amortized to interest expense equitably over the life of the replacement or retired issue as applicable.

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

Energy efficiency programs - PGE's energy efficiency program expenditures, formerly deferred and amortized, have been expensed directly since October 1, 2000. The unamortized balance of those expenditures incurred prior to October 1, 2000, as well as amounts recoverable under the Company's SAVE energy efficiency program and certain other energy efficiency costs, have been fully recovered from retail customers at December 31, 2005. Beginning March 1, 2002, energy efficiency program expenditures and amounts reimbursed from public purpose funds administered by the Energy Trust of Oregon are charged and credited, respectively, to Other Income (Deductions).

Power cost adjustment mechanism - In February 2001, the OPUC authorized PGE to defer for recovery from customers a portion of its net variable power costs in excess of a baseline amount during the period January through September 2001. The deferred amount was recovered over the period April 1, 2002 through December 31, 2005.

PGE did not have power cost adjustment mechanisms for 2004 and 2005 and currently has none in place for 2006.

Regulatory restructuring costs - The OPUC authorized PGE to defer certain costs related to implementation of Oregon's electric restructuring law. Approximately \$7 million is currently being recovered in prices charged to customers over a six-year period that began on January 1, 2003, with a remaining balance of \$3 million at December 31, 2005. The remaining \$17 million in implementation costs is being recovered over a five-year period that began on January 1, 2004, with a remaining balance of \$13 million at December 31, 2005.

Beaver 8 - In December 2004, the OPUC issued an Order that adopted a stipulation in which parties agreed that PGE may recover from customers approximately \$14 million for costs associated with a 24.7 MW combustion turbine (referred to as Beaver 8) installed at the Company's Beaver generating plant site in 2001. Of this amount, \$10 million (plus accrued interest) was deferred for recovery from customers over a five-year period beginning January 1, 2005. The remaining \$4 million, representing the current market value of the turbine, remains in plant in service and is depreciated over its useful life. The plant costs are included in rate base in PGE's general rate case, filed with the OPUC in March 2006.

Pelton Round Butte tax benefits recoverable - In 2002, PGE sold a 33.33% interest in the Pelton Round Butte hydroelectric project for PGE's net book value, in accordance with an agreement approved by the OPUC. The sales price did not include recovery of approximately \$5 million in income tax benefits that had been flowed to customers in prior years. The OPUC authorized PGE to defer the income taxes recoverable for future rate recovery. Such recovery was completed over a two-year period that began on January 1, 2004.

Asset retirement obligations - SFAS No. 143, Accounting for Asset Retirement Obligations, which was adopted on January 1, 2003, requires the recognition of AROs, measured at estimated fair value, for legal obligations related to dismantlement and restoration costs associated with the retirement of tangible long-lived assets in the period in which the liability is incurred. Pursuant to regulation, AROs of rate-regulated long-lived assets are included as an allowable cost in rates charged to customers. Any differences in the timing of recognition of costs for financial reporting and ratemaking purposes are deferred as a regulatory asset or regulatory liability under SFAS No. 71. Asset retirement obligations are included in PGE's rate base for ratemaking purposes.

Accumulated asset retirement removal costs - Asset retirement removal costs that do not qualify as AROs are a component of depreciation expense allowed in customer rates. Accumulated asset retirement removal costs are recorded as a regulatory liability as they are collected in rates, and are reduced by actual removal costs as incurred, in accordance with SFAS No. 143 and SFAS No. 71. This amount is also included as a reduction to PGE's rate base for ratemaking purposes.

Price risk management - SFAS No. 133 requires unrealized gains and losses on derivative instruments that do not qualify for the normal purchase and normal sale exception to be recorded in earnings and other comprehensive income in the current period. To reflect the effects of regulation under SFAS No. 71, timing differences between the recognition of gains and losses on certain non-trading derivative instruments and their realization and subsequent recovery in rates are recorded as regulatory assets or regulatory liabilities. Amounts recorded by PGE at December 31, 2005 and 2004 offset the effects of such gains and losses, which are caused by changes in fair values of related energy contracts; recorded amounts are reversed as such contracts are settled. See Note 8, Price Risk Management, for further information.

Information technology costs - In PGE's 2001 general rate filing, the OPUC approved an estimated amount of capital expenditures related to the Company's Customer Information System (CIS) and Information Technology (IT) activities in the determination of PGE's 2002 revenue requirement. The Commission's rate order stipulated that PGE's retail customers are to receive a refund if the actual revenue requirement for such costs is less than the estimated revenue requirement. Accordingly, regulatory liabilities of \$4 million were recorded in 2005, 2004, and 2003, to reflect the difference between actual and estimated revenue requirements related to CIS and IT capital expenditures. Amounts deferred are being refunded to customers through 2006. A \$4 million annual deferral will continue until new base rates are established.

Trojan ISFSI Pollution Control Tax Credits - In December 2004, PGE received final certification from the Oregon Environmental Quality Commission (OEQC) related to \$21.1 million in Oregon pollution control tax credits that were generated from PGE's investment in an Independent Spent Fuel Storage Installation (ISFSI) at Trojan. OEQC rules require that the tax credits be spread over a ten-year period, beginning in 2004. The OPUC approved the deferral of the tax credits for future ratemaking treatment. See Note 12, Trojan Nuclear Plant, for further information.

Oregon corporation excise tax refund - Oregon's constitution provides for a Corporation Excise Tax refund when actual state tax revenues exceed those estimated in the state's budget. In 2005, PGE was notified that it will receive a tax credit related to the difference between estimated and actual state excise taxes collected during the state's 2003-2005 biennium, with such refund to be reflected as a credit against the Company's net 2005 tax liability. PGE's share of the state tax credit is being deferred for future refund to customers.

Recovery/refund period - As of December 31, 2005, the majority of PGE's regulatory assets and liabilities are reflected in customer rates. Based on such rates, the Company estimates that it will collect substantially all of its regulatory assets, and refund its regulatory liabilities (excluding those related to asset retirement obligations and removal costs), within the next 14 years.

New Accounting Standards

FASB Interpretation No. 47 (FIN 47), Accounting for Conditional Asset Retirement Obligations - an interpretation of FASB Statement No. 143, was issued in March 2005 and is effective no later than the end of fiscal years ending after December 15, 2005. FIN 47 clarifies that the term "conditional asset retirement obligation" as used in FASB Statement No. 143, Accounting for Asset Retirement Obligations, refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. An entity is required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated, even though uncertainty exists about the timing and (or) method of settlement. PGE's adoption of FIN 47 on December 31, 2005 did not have a material effect on the financial statements of the Company.

FASB Staff Position No. FAS 13-1 (FSP 13-1), Accounting for Rental Costs Incurred during a Construction Period, addresses the accounting for rental costs associated with ground and building operating leases that are incurred during a construction period. FSP 13-1 requires that rental costs associated with ground or building operating leases incurred during a construction period be recognized as rental expense and included in income from continuing operations. The application of FSP 13-1, which is required in the first reporting period beginning after December 15, 2005, is not expected to have a material effect on the financial statements of the Company.

SFAS No. 123R (SFAS 123R), Share-Based Payment, was issued in December 2004 and replaces SFAS No. 123, Accounting for Stock-Based Compensation. Companies that issue share-based payment awards to employees are required to recognize compensation expense based on the fair value of the expected vested portion of the award as of the grant date over the vesting period of the award. Forfeitures that occur before the award vesting date will be adjusted from the total compensation expense, but once the award vests, no adjustment to compensation expense will be allowed for forfeitures or unexercised awards. In addition, SFAS 123R would require recognition of compensation expense of all existing outstanding awards that are not fully vested for their remaining vesting period as of the effective date that were not accounted for under a fair value method of accounting at the time of their award. SFAS 123R is effective for annual reporting periods beginning after June 15, 2005. PGE had no outstanding equity based awards at December 31, 2005 and is evaluating the impact of the application of SFAS 123R and SEC Staff Accounting Bulletin No. 107 with respect to any future equity awards granted by the Company.

Note 2 - Employee Benefits

Pension and Other Post-Retirement Plans

Defined Benefit Pension Plan - PGE sponsors a non-contributory defined benefit pension plan, of which substantially all members are current or former PGE employees. The assets of the pension plan are held in a trust. Pension plan calculations include several assumptions which are reviewed annually with PGE's consulting actuaries and updated as appropriate. In 2005, PGE updated the mortality rate assumption used for the pension plan, which resulted in a \$14 million increase in the accumulated benefit obligation included in the accompanying table.

In August 2005, PGE transferred \$3 million in pension assets from PGE's pension plan to Enron Corp.'s Cash Balance Plan to reflect a net exchange of assets and benefit obligations. These exchanges consolidated benefits for certain individuals who had changed employers and as a result had ceased earning benefits under one plan and began earning benefits under the other plan. The transfer is included in "Divestitures" in the accompanying table.

In December 2005, PGE made a \$10 million cash contribution to the pension plan. No contributions were made in 2004. PGE does not expect to make a contribution to the pension plan in 2006. The measurement date for the pension plan is December 31.

Non-Qualified Benefit Plans - The Non-Qualified Benefit Plans in the accompanying table primarily represent obligations for a Supplemental Executive Retirement Plan (SERP). The SERP was closed to new participants in 1997. Investments in a non-qualified benefit plan trust (i.e. rabbi trust), consisting of trust owned life insurance policies (TOLI) and, beginning in 2003, marketable securities, are intended to be the primary source for financing these plans. Trust assets of \$24 million as of December 31, 2005 and \$22 million as of December 31, 2004 are shown in the accompanying table for informational purposes only and are not considered segregated and restricted as defined by SFAS No. 87, Employers' Accounting for Pensions. The investments in marketable securities, consisting of money market, bond, and equity mutual funds, are classified as trading and recorded at fair value. Unrealized gains in marketable securities were \$1 million for each of the years 2005, 2004, and 2003. In addition, recognized gains on trust assets of \$1 million for both 2005 and 2004 and \$2 million for 2003 are included in net periodic benefit cost. The basis on which cost is determined in computing realized gains and losses on marketable securities is average cost. The measurement date for the non-qualified plans is December 31.

In April 2005, PGE assumed \$2 million of non-qualified benefits plan liabilities from Portland General Holdings (PGH) as part of a settlement with certain PGH participants. PGE also received \$2 million in trust assets to be used for payment of benefits. These amounts are included in "Assumed plans" in the accompanying table.

Other Benefits - PGE also participates in non-contributory post-retirement health and life insurance plans ("Other Benefits" in the table). Employees are covered under a Defined Dollar Medical Benefit Plan which limits PGE's obligation by establishing a maximum contribution per employee. Contributions made to a voluntary employees' beneficiary association (VEBA) trust are used to fund these plans. Costs of these plans, based upon an actuarial study, are included in rates charged to customers. Post-retirement benefit plan calculations include several assumptions which are reviewed annually with PGE's consulting actuaries and updated as appropriate. In 2005, PGE updated the mortality rate assumption used for the post-retirement benefits. The impact of this change on the benefit obligation was not significant.

In 2004, PGE established Health Retirement Accounts (HRAs) for its employees under which the Company agreed to make contributions to a trust to provide for claims by retirees for qualified medical costs. The 2004 bargaining unit agreement provides that retired employees may submit claims to the HRA for qualified medical expenses up to 58% of the value of any accumulated sick time at their retirement. The Company also granted a fixed dollar amount for all active non-bargaining employees which will become available for qualified medical expenses upon their retirement. As a result of the HRAs, the benefit obligation increased \$6 million in 2004.

No contributions were made to the post-retirement plans in 2004. In 2005, PGE contributed \$2 million to the HRAs. Contributions to the HRAs in 2006 are expected to be minimal. No contributions are expected to be made to the other post-retirement plans in 2006. The measurement date for the post-retirement plans and the HRAs is December 31.

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

	<u>Defined Benefit Pension Plan</u>		<u>Non-Qualified Benefit Plans</u>		<u>Other Benefits</u>	
	<u>2005</u>	<u>2004</u>	<u>2005</u>	<u>2004</u>	<u>2005</u>	<u>2004</u>
Reconciliation of benefit obligation:						
Obligation at January 1	\$ 450	\$ 400	\$ 22	\$ 21	\$ 55	\$ 45
Service cost	12	12	-	-	1	1
Interest cost	25	24	1	2	3	3
Plan amendments	-	2	-	-	-	1
New plans	-	-	-	-	-	6
Assumed plans	-	-	2	-	-	-
Divestitures	(3)	-	-	-	-	-
Participants' contributions	-	-	-	-	1	1
Actuarial loss	18	29	1	1	2	2
Benefit payments	(19)	(17)	(2)	(2)	(3)	(4)
Obligation at December 31	<u>\$ 483</u>	<u>\$ 450</u>	<u>\$ 24</u>	<u>\$ 22</u>	<u>\$ 59</u>	<u>\$ 55</u>
Reconciliation of fair value of plan assets:						
Fair value of plan assets at January 1	\$ 452	\$ 415	\$ 22	\$ 22	\$ 26	\$ 26
Actual return on plan assets	29	54	2	2	1	3
Company contributions	10	-	-	-	2	-
Assumed plans	-	-	2	-	-	-
Participants' contributions	-	-	-	-	1	1
Divestitures	(3)	-	-	-	-	-
Benefit payments	(19)	(17)	(2)	(2)	(3)	(4)
Fair value of plan assets at December 31	<u>\$ 469</u>	<u>\$ 452</u>	<u>\$ 24</u>	<u>\$ 22</u>	<u>\$ 27</u>	<u>\$ 26</u>
Funded status:						
Funded (unfunded) status at December 31	\$ (14)	\$ 2	\$ -	\$ -	\$ (32)	\$ (29)
Unrecognized transition liability	-	-	-	-	2	2
Unrecognized prior service cost	5	6	-	1	7	8
Unrecognized loss	97	70	3	2	11	10
Prepaid pension cost (liability)	<u>\$ 88</u>	<u>\$ 78</u>	<u>\$ 3</u>	<u>\$ 3</u>	<u>\$ (12)</u>	<u>\$ (9)</u>
Accumulated benefit obligation	\$ 426	\$ 394	\$ 21	\$ 19	N/A	N/A
Amounts recognized in the Balance Sheet consist of:						
Prepaid benefit cost	\$ 88	\$ 78	\$ 8	\$ 9	\$ (12)	\$ (9)
Accumulated other comprehensive income	-	-	(5)	(6)	-	-
Net amount recognized	<u>\$ 88</u>	<u>\$ 78</u>	<u>\$ 3</u>	<u>\$ 3</u>	<u>\$ (12)</u>	<u>\$ (9)</u>
Assumptions:						
Discount rate used to calculate benefit obligation	5.75%	5.75%	5.75%	5.75%	5.50%	5.75%
Weighted average rate of increase in future compensation levels	4.43%	4.48%	N/A	N/A	5.30%	5.30%
Long-term rate of return on assets	9.00%	9.00%	N/A	N/A	8.62%	8.63%

	<u>Defined Benefit Pension Plan</u>			<u>Non-Qualified Benefit Plans</u>			<u>Other Benefits</u>		
	<u>2005</u>	<u>2004</u>	<u>2003</u>	<u>2005</u>	<u>2004</u>	<u>2003</u>	<u>2005</u>	<u>2004</u>	<u>2003</u>
Components of net periodic benefit cost:									
Service cost	\$ 12	\$ 12	\$ 11	\$ -	\$ -	\$ -	\$ 1	\$ 1	\$ 1
Interest cost on benefit obligation	25	24	23	1	1	2	3	3	3
Expected return on plan assets	(41)	(40)	(39)	-	-	-	(2)	(2)	(1)
Amortization of transition asset	-	(2)	(2)	-	-	-	1	1	-
Amortization of prior service cost	2	2	1	1	1	-	1	-	-
Recognized (gain) loss	2	-	-	(1)	(1)	(2)	1	-	1
Net periodic benefit cost (income)	<u>\$ -</u>	<u>\$ (4)</u>	<u>\$ (6)</u>	<u>\$ 1</u>	<u>\$ 1</u>	<u>\$ -</u>	<u>\$ 5</u>	<u>\$ 3</u>	<u>\$ 4</u>

The following table summarizes the benefits expected to be paid to participants in each of the next five years and in the aggregate for the five years thereafter (in millions):

	Payments Due					2011 - 2015
	2006	2007	2008	2009	2010	
Pension Plan Payments (*)	\$24	\$24	\$25	\$25	\$26	\$159
Non-Qualified Plan Payments	2	2	2	1	1	10
Other Plan Payments	3	4	4	4	4	22
Total	\$29	\$30	\$31	\$30	\$31	\$191

(*) Increases in Pension Plan Payments from amounts estimated in prior years reflect updated mortality assumptions (discussed above) and increases in expected retirement rates.

All of the plans develop expected long-term rates of return for the major asset classes using long-term historical returns with adjustments based on current levels and forecasts of inflation, interest rates, and economic growth. Also included are incremental rates of return provided by investment managers whose returns are expected to be greater than the markets in which they invest.

For measurement purposes, a 9% annual rate of increase in the per capita cost of covered health care benefits is assumed for 2006. The rate is assumed to decrease to 5% by 2013 and remain at that level thereafter. Assumed health care cost trend rates can affect amounts reported for the health care plans. A one-percentage point change in assumed health care cost trend rates would have the following effects (in millions):

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

The asset allocation for the pension plan at December 31, 2005 and 2004 and the target allocation for 2006, by asset category, are as follows:

Asset Category	Percentage of Plan Assets December 31		Target Allocation
	2005	2004	2006
Equity Securities	67%	70%	67%
Debt Securities	33%	30%	33%
Total	100%	100%	100%

The asset allocation for the Non-Qualified Benefit Plans at December 31, 2005 and 2004 are as follows:

Asset Category	Percentage of Plan Assets		Target Allocation
	December 31		
	<u>2005</u>	<u>2004</u>	<u>2006</u>
Cash Equivalents	10%	-	-
Debt Securities	7%	26%	10%
Equity Securities	37%	26%	52%
TOLI Policies	46%	48%	38%
Total	<u>100%</u>	<u>100%</u>	<u>100%</u>

An insurable interest in the respective employees is required for investment in TOLI policies. PGE does not establish target allocations between the TOLI assets and the remaining investments.

The asset allocation for the Other Benefit Plans at December 31, 2005 and 2004, and the target allocation for 2006, by asset category, are as follows:

Asset Category	Percentage of Plan Assets		Target Allocation
	December 31		
	2005	2004	2006
Equity Securities	68%	69%	68%
Debt Securities	32%	31%	32%
Total	100%	100%	100%

The Plans' investment policies call for permanent commitment to five asset classes to promote diversification at the plan level. The commitments to each class are controlled by an Asset Deployment Policy and Cash Management Policy that take profits from asset classes whose allocations have shifted above their target ranges to fund benefit payments and investments in asset classes whose allocations have shifted below their target ranges.

Other Non-Qualified Benefit Plans

In addition to the SERP Plan discussed above, PGE provides certain employees with benefits under an unfunded Management Deferred Compensation Plan (MDCP) whereby participants may defer a portion of their pay. Obligations for the MDCP were \$54 million and \$51 million at December 31, 2005 and 2004, respectively (not included in table). The costs of the SERP and MDCP Plans are excluded from prices charged to customers. Investments in trust owned life insurance policies and, beginning in 2003; marketable securities, are intended to be the primary source for financing the MDCP Plan. Total assets held in support of the MDCP Plan were \$39 million at December 31, 2005 and \$40 at December 31, 2004. Unrealized gains in marketable securities were \$1 million for 2005 and 2004 and \$2 million for 2003.

PGE sponsors additional non-qualified plans for certain employees and former directors. Obligations for these plans are minimal. Assets held in support of these plans totaled \$2 million at December 31, 2005 and 2004.

In April 2005, PGE assumed \$5 million of MDCP and Directors Deferred Compensation plan liabilities from PGH as part of a settlement with certain PGH participants. PGE also received \$5 million in trust assets to be used for payment of benefits. Obligations for the PGH liabilities at December 31, 2005 were \$4 million. Total trust assets held in support of the PGH liabilities were also \$4 million at December 31, 2005.

401(k) Retirement Savings Plan

PGE participated in the Enron Corp. Savings Plan during 2004. At the end of the year, employee balances were transferred from the Enron Corp. Savings Plan to a new 401(k) Plan sponsored by PGE, which became effective on January 1, 2005. Contribution provisions, described below, did not change.

Contributions to the plan by eligible employees, made on a "pre-tax" basis, are matched by the Company up to a specified maximum percentage of the participating employee's base salary. For non-bargaining unit employees, contributions up to 6% of base pay are matched by the Company.

For bargaining unit employees, contributions are based upon provisions of the IBEW union agreement that became effective on March 1, 2004. Contributions to the 401(k) Plan by those employees who are also covered by a defined benefit pension plan are matched by the Company at up to 6% of base pay. Contributions by those employees not covered by a defined benefit pension plan will be matched until 2009 by the Company up to 8% of base pay, based upon both the employee's age and years of service; in addition, PGE contributes from 5% to 10% of base pay, based upon the employee's age.

All contributions to the plan are invested in accordance with employees' individual investment choices. PGE made matching contributions to its employees' savings plan accounts of approximately \$13 million in 2005, \$12 million in 2004, and \$10 million in 2003.

Note 3 - Income Taxes

The following table indicates the detail of taxes on income and the items used in computing the differences between the statutory federal income tax rate and PGE's effective tax rate (in millions):

	2005	2004	2003
Income Tax Expense			
Current:			
Federal	\$88	\$59	\$59
State and local	8	8	7
	<u>96</u>	<u>67</u>	<u>66</u>
Deferred:			
Federal	(41)	(8)	(19)
State and local	(9)	(2)	-
	<u>(50)</u>	<u>(10)</u>	<u>(19)</u>
Investment tax credit adjustments	<u>(3)</u>	<u>(3)</u>	<u>(3)</u>
Total income tax expense before cumulative effect of a change in accounting principle	<u>\$43</u>	<u>\$54</u>	<u>\$44</u>
Income tax expense allocated to:			
Operations	\$46	\$57	\$50
Other income and deductions	<u>(3)</u>	<u>(3)</u>	<u>(6)</u>
Total income tax expense before cumulative effect of a change in accounting principle	<u>\$43</u>	<u>\$54</u>	<u>\$44</u>
Effective Tax Rate Computation:			
Computed tax based on statutory federal income tax rate (35%) applied to income before income taxes	\$37	\$51	\$35
Flow through depreciation	7	9	7
State and local taxes - net of federal tax benefit	1	5	4
Investment tax credits	(3)	(3)	(3)
Excess deferred taxes	(1)	(1)	(1)
Adjustments for previously-recorded taxes	2	(3)	-
Other	<u>-</u>	<u>(4)</u>	<u>2</u>
Total income tax expense before cumulative effect of a change in accounting principle	<u>\$43</u>	<u>\$54</u>	<u>\$44</u>
Effective tax rate	39.9%	37.0%	44.0%

As of December 31, 2005 and 2004, the significant components of PGE's deferred income tax assets and liabilities were as follows (in millions):

	<u>2005</u>	<u>2004</u>
<u>Deferred income tax assets</u>		
Depreciation and amortization	\$ 35	\$ 37
Employee benefits	34	31
Allowance for uncollectible accounts	20	20
Land reclamation costs	3	3
Regulatory liabilities		
Asset retirement removal costs	139	113
Other	39	9
Other	17	22
Total deferred income tax assets	<u>287</u>	<u>235</u>
<u>Deferred income tax liabilities</u>		
Depreciation and amortization	463	465
Employee benefits	27	24
Property taxes	5	5
Price risk management	26	4
Regulatory assets		
Prior tax benefits recoverable	-	4
Debt reacquisition costs	8	9
Conservation investments	3	7
Energy efficiency programs	4	12
Power cost adjustment	-	7
Miscellaneous	11	13
Other	9	13
Total deferred income tax liabilities	<u>556</u>	<u>563</u>
Net deferred income taxes	<u>\$ 269</u>	<u>\$ 328</u>
<u>Classification of net deferred income taxes</u>		
Included in current liabilities	\$ 51	\$ 15
Included in non current liabilities	218	313
Net deferred income taxes	<u>\$ 269</u>	<u>\$ 328</u>

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

(Dollars in Millions)	<u>Common Stock</u>		<u>Limited Voting Junior Preferred</u>		<u>Paid-in Capital</u>
	<u>Number of Shares</u>	<u>\$3.75 Par Value</u>	<u>Number of Shares</u>	<u>\$1.00 Par Value</u>	
December 31, 2003	42,758,877	\$160	1	-	\$481
December 31, 2004	42,758,877	160	1	-	481
December 31, 2005	42,758,877	160	1	-	482

Limited Voting Junior Preferred Stock

On September 30, 2002, following approval by the Bankruptcy Court, Debtor-in-Possession lenders, the OPUC, and PGE's Board of Directors, a single share of \$1.00 par value Limited Voting Junior Preferred Stock (Junior Preferred) was issued by PGE to an independent party. The Junior Preferred has no dividend, a liquidation preference to the Common Stock as to par value but junior to existing preferred stock, and certain restrictions on transfer. It also has voting rights, which limit, subject to certain exceptions, PGE's right to commence any voluntary bankruptcy, liquidation, receivership, or similar proceedings (Bankruptcy) without the consent of the holder of the share of Junior Preferred, and may be redeemed for its par value at any time after PGE is no longer under the control (as defined) of any person or entity, or of any affiliate of such person or entity that is subject to an order for relief under the United States Bankruptcy Code or any successor statute. On March 14, 2006, PGE's Board of Directors authorized the Junior Preferred stock to be redeemed on March 28, 2006. Upon redemption, the Junior Preferred will be cancelled and will not be reissued.

Common Stock Dividends

Enron owns all of the issued and outstanding common stock of PGE. Under Oregon law and specific OPUC merger conditions, Enron's access to PGE cash or assets (through dividends or otherwise) is limited. PGE is restricted from paying dividends or making other distributions to Enron without prior OPUC approval to the extent that such payment or distribution would reduce PGE's common equity capital below 48% of its total capitalization (excluding short-term borrowings). Management believes that, at December 31, 2005, the Company has the ability to pay dividends, notwithstanding this restriction:

The OPUC order approving the issuance of new PGE common stock (see "Common Stock Issuance" below) includes a stipulation containing several conditions, including a requirement that, after issuance of the new stock, PGE cannot pay a dividend that would cause the common equity capital percentage to fall below 48% (plus \$40 million) without Commission approval. PGE has agreed to maintain the additional \$40 million of common equity pending the outcome of its next general rate case to assure the Company's financial capacity to absorb any adjustment(s) in its revenue requirement related to its ownership by Enron. The requirement is reduced to 45% when the Disputed Claims Reserve (DCR) holds between 20% and 40% of the issued and outstanding common stock of PGE, with no minimum common equity capital percentage requirement when the DCR holds less than 20% of the issued and outstanding common stock of PGE. Other conditions include a requirement that the OPUC be notified (simultaneously with the public) of any dividend declared by PGE's Board of Directors and that, before the issuance of new common stock, PGE cannot make a dividend distribution to Enron unless PGE has a rating on its senior secured debt of not lower than BBB+ from Standard & Poor's.

Common Stock Issuance

In accordance with the Chapter 11 Plan, Enron plans to distribute new PGE common stock to the Debtors' creditors holding allowed claims. Current PGE common stock held by Enron will be cancelled and 62,500,000 shares (of 80,000,000 shares authorized) of new PGE common stock without par value will be distributed over time to Debtors' creditors holding allowed claims. Initially, at least 30 percent of the new PGE common stock will be issued by PGE to the Debtors' creditors that hold allowed claims, with the remainder issued to a Disputed Claims Reserve (DCR) where it will be held to be released over time to the Debtors' creditors holding allowed claims in accordance with the Chapter 11 Plan.

At the time the new common stock issuance takes place, currently expected on or about April 3, 2006, PGE's balance sheet will be adjusted to reflect the combined book values of the current \$3.75 par value common stock and Other paid-in capital into the new item "Common stock, no par value". Costs incurred for the issuance of new common stock, and to become a publicly-traded company, are charged to operating expense as incurred.

Note 5 - Credit Facility and Debt

At December 31, 2005, PGE had a \$400 million five-year unsecured revolving credit facility with a group of commercial banks. The facility, which expires in 2010, replaced the Company's \$50 million 364-day revolving credit facility, which expired in May 2005, and a \$100 million three-year facility. It is available for general corporate purposes, with the maximum amount available to PGE for borrowings and/or the issuance of standby letters of credit. At December 31, 2005, PGE had utilized approximately \$17 million in letters of credit.

The facility allows PGE to borrow for one, two, three, or six months at a fixed interest rate established at the time of the borrowing, or at a variable interest rate for any period up to the then remaining term of the facility. The facility provides that all outstanding loans mature on the termination date of the facility, provided that such date may be extended for an additional year for those lenders who agree to an extension. The facility requires annual fees based on PGE's unsecured credit rating, and contains customary covenants and default provisions, including a requirement that limits consolidated indebtedness, as defined in the facility, to 65% of total capitalization. At December 31, 2005, PGE was in compliance with this covenant.

PGE management believes that its existing line of credit and cash from operations provide the Company with sufficient liquidity to meet its day-to-day cash requirements. As of December 31, 2005, the Company has sufficient capacity under its Indenture of Mortgage to issue additional First Mortgage Bonds in amounts sufficient to meet its anticipated capital requirements and to supplement day-to-day cash requirements to the extent necessary.

PGE had no short-term borrowings in 2004 or 2005.

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:

	<u>2005</u>	<u>2004</u>
	(In Millions)	
First Mortgage Bonds		
Maturing 2005 - (9.07%)	\$ -	\$ 18
Maturing 2007 - (7.15%)	50	50
Maturing 2010 - (8 1/8%)	150	150
Maturing 2012 - (5.6675%)	100	100
Maturing 2013 - (5.279% - 5.625%)	100	100
Maturing 2021 - 2033 (6.75% - 9.31%)	120	120
	<u>520</u>	<u>538</u>
Pollution Control Bonds		
Port of Morrow, Oregon, variable rate, due 2033 (5.20% fixed rate to 2009)	23	23
City of Forsyth, Montana, variable rate, due 2033 (5.20% - 5.45% fixed rate to 2009)	119	119
Port of St. Helens, Oregon, 4.80% due 2010	37	37
Port of St. Helens, Oregon, due 2014 (5.25% - 7.13% fixed rate)	15	15
	<u>194</u>	<u>194</u>
Other		
6.91% Conservation Bonds maturing monthly to 2006 (a)	9	20
7.875% Notes due March 15, 2010	149	149
7.75% Series Cumulative Preferred Stock (a) (b)	19	22
Unamortized debt discount	(1)	(1)
	<u>176</u>	<u>190</u>
	890	922
Long-term debt due within one year (a)	(11)	(30)
Total long-term debt	<u>\$ 879</u>	<u>\$ 892</u>

(a) Due within one year; consists of \$9 million of Conservation Bonds, and \$2 million of 7.75% Series Cumulative Preferred Stock.

(b) The 7.75% Series Cumulative Preferred Stock (no par value), which is mandatorily redeemable, is classified as long-term debt in accordance with SFAS No. 150. The preferred stock series is redeemable by operation of a sinking fund that requires the annual redemption of 15,000 shares at \$100 per share beginning in 2002, with all remaining shares to be redeemed by sinking fund in 2007. At its option, PGE may redeem, through the sinking fund, an additional 15,000 shares each year. Open market share purchases can be applied towards the annual redemption requirement. In 2005, PGE redeemed 30,000 shares, consisting of 15,000 shares for the annual sinking fund requirement and 15,000 additional shares acquired at its option. At December 31, 2005, there were 189,727 shares outstanding.

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

	2006	2007	2008	2009	2010	Thereafter	Total
Debt Maturities	\$11	\$67	\$ -	\$ -	\$335	\$477	\$890

Note 6 - Other Financial Instruments

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

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

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

Long-term debt - The fair value of long-term debt is estimated based on the quoted market prices for the same or similar issues or on the current rates offered to PGE for debt of similar remaining maturities. The estimated fair values of debt instruments are as follows (in millions):

	<u>2005</u>		<u>2004</u>	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt including current maturities	<u>\$890</u>	<u>\$950</u>	<u>\$922</u>	<u>\$1,005</u>

Note 7 - Commitments and Guarantee

Natural Gas Agreements

PGE has entered into agreements for the purchase and transportation of natural gas from domestic and Canadian sources for its natural gas-fired generating facilities. The Company has also entered into a ten-year natural gas storage agreement, effective May 1, 2007, for the purpose of fueling the Company's Port Westward and Beaver generating plants located adjacent to the storage facility. As of December 31, 2005, these agreements require net payments of approximately \$35 million in 2006, \$17 million in both 2007 and 2008, \$15 million in 2009, \$13 million in 2010, and \$41 million over the remaining years of the contracts, which expire at varying dates from 2006 to 2017.

Purchase Commitments

Certain commitments have been made for capital and other purchases for 2006 and beyond. Such commitments total \$404 million as of December 31, 2005, reflecting future payment requirements of \$192 million in 2006, \$43 million in 2007, and \$54 million in 2008, \$33 million in 2009, \$10 million in 2010, and \$72 million over the remaining years of the commitments. Such commitments include those related to construction of Port Westward, Trojan decommissioning activities, hydro license agreements, information systems, upgrades to production and distribution facilities, and system maintenance work. Termination of these agreements could result in cancellation charges.

Coal and Transportation Agreements

PGE has coal and related rail transportation agreements with take-or-pay provisions of approximately \$13 million annually in 2006 and 2007, and \$14 million in 2008, and \$3 million annually from 2009 through 2013.

Purchased Power

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

	Rocky Reach	Priest Rapids	Wanapum	Wells	Portland Hydro
Revenue bonds outstanding at December 31, 2005	\$381	\$210	\$291	\$232	\$ 22
PGE's current share of:					
Output	12.0%	7.5%	18.7%	19.4%	100%
Net capability (megawatts)	136	56	133	131	36
PGE's annual cost, including debt service:					
2005	\$ 8	\$ 4	\$ 7	\$ 6	\$ 5
2004	8	4	6	6	5
2003	9	4	7	7	5
Contract expiration date	2011	*	2009	2018	2017

* Expires at the end of the license term to be determined by the FERC.

PGE's share of debt service costs, excluding interest, is approximately \$7 million annually in 2006 and 2007, \$8 million annually in 2008 and 2009, and \$7 million in 2010. Total minimum payments through the remainder of the contracts are estimated at \$51 million.

PGE has executed new agreements with Grant County Public Utility District (Grant), operator of the Priest Rapids and Wanapum projects, for periods corresponding to Grant's new license term, to be determined by the FERC. The new Priest Rapids agreement became effective November 1, 2005. The new Wanapum agreement is effective upon expiration of the current contract and the issuance of a new license to Grant. Under the agreements, Grant will annually determine the output required for its purposes, with PGE required to purchase approximately 25% of the output beyond Grant's needs over the term of the new license, for which PGE will pay a proportional share of the project's debt service and operating costs.

In November 2004, Douglas County PUD (Douglas), owner of the Wells Hydroelectric Project (Project), entered into a settlement with the Colville Confederated Tribes (Colville Tribe) that resolved claims for charges for the use of Colville tribal lands. The settlement, which was approved by the FERC in February 2005, impacted the quantity and price of PGE's share of the output of the Project. The settlement required that Douglas pay a \$13.5 million lump sum, convey certain real property, and allocate (at cost) 4.5% of Project's output to the Colville Tribe; such allocation increases to 5.5% for all years after 2018. To fund the \$13.5 million payment, PGE and other purchasers of the Project's output entered into a Settlement Endorsement Agreement (Agreement) providing for the sale by Douglas of revenue bonds. The Agreement requires that each purchaser of the Project's output pay their respective share of debt service on the revenue bonds, with PGE's annual share calculated at approximately \$350,000. In addition to its share of debt service payments, PGE's share of the Project's output was reduced from 20.3% to 19.4% beginning in April 2005. The effects of both the debt service requirement and the reduction in output were included in projected power costs in PGE's final 2005 and 2006 RVM filings approved by the OPUC.

As of December 31, 2005, PGE has power purchase contracts with other counterparties, requiring payments of approximately \$706 million in 2006, \$304 million in 2007, \$90 million in both 2008 and 2009, \$91 million in 2010, and \$645 million over the remaining years of the contracts, which expire at varying dates from 2011 to 2035. As of December 31, 2005, PGE has power sale contracts with other counterparties of approximately \$230 million in 2006, \$70 million in 2007, \$14 million in 2008, \$12 million in 2009, \$11 million in 2010, and \$16 million over the remaining years of the contracts, which expire at varying dates from 2011 to 2012. PGE also has power capacity contracts as of December 31, 2005 that require payments of approximately \$24 million annually from 2006 through 2010 and are expected to average approximately \$20 million from 2011 through 2016.

PGE has two long-term power exchange contracts. One exchange contract is with a summer-peaking California utility to help meet the Company's winter-peaking power requirements. There was no outstanding exchange balance under this contract at December 31, 2005. The other exchange contract is with a winter-peaking Northwest utility to help meet the Company's summer-peaking power requirements. At December 31, 2005, PGE owed 8,667 MWhs of electricity, all of which was delivered by the end of February 2006.

Leases

PGE has an operating lease for its headquarters complex located in Portland, Oregon. In May 2005, PGE purchased the coal-handling facility at Boardman, which the Company had previously leased. Lease payments charged to expense totaled \$8 million in 2005 and \$10 million in both 2004 and 2003.

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

Year Ending December 31	Operating Leases (Net of Sublease Rentals)
2006	\$ 7
2007	7
2008	7
2009	7
2010	7
Remainder	<u>181</u>
Total	<u>\$216</u>

Included in the above table is approximately \$126 million for PGE's headquarters complex reflecting the base lease period through 2018 and renewal period options through 2043.

Guarantee

PGE entered into a sale transaction in 1985 in which it sold an undivided 15% interest in its Boardman coal plant (Plant) and a 10.714% undivided interest in the Pacific Northwest Intertie (Intertie) transmission line (jointly the Boardman Assets) to an unrelated third party (Purchaser). The Purchaser leased the Boardman Assets to a lessee (Lessee) unrelated to PGE or the Purchaser. Concurrently, PGE assigned to the Lessee certain agreements for the sale of power and transmission services from the Plant and the Intertie (P&T Agreements) to a regulated electric utility (Utility) unrelated to PGE, the Purchaser, or the Lessee. The payments by the Utility under the P&T Agreements exceed the payments to be made by the Lessee to the Purchaser under the lease. In exchange for PGE undertaking certain obligations of the Lessee under the lease, the Lessee reassigned to PGE certain rights, including the excess payments, under the P&T Agreements. However, in the event that the Utility defaults on the payments it owes under the P&T Agreements, PGE may be required to pay the damages owed by the Lessee to the lessor under the lease. Assuming no recovery from the Utility and no reduction in damages from mitigating sales or leases related to the Boardman Assets and P&T Agreements, the maximum amount that would be owed by PGE in 2006 is approximately \$205 million. Management believes that circumstances that could result in such amount, or any lesser amount, being owed by the Company are remote.

Note 8 - Price Risk Management

PGE utilizes derivative instruments, including electricity forward, swap, and option contracts and natural gas forward, swap, option, and futures contracts in its retail (non-trading) electric utility activities to manage its exposure to commodity price risk and to minimize net power costs for service to its retail customers. Under SFAS No. 133, derivative instruments are recorded on the Balance Sheet as an asset or liability measured at estimated fair value, with changes in fair value recognized currently in earnings, unless specific hedge accounting criteria are met.

Changes in the fair value of retail (non-trading) derivative instruments prior to settlement that do not qualify for either the normal purchase and normal sale exception or for hedge accounting are recorded on a net basis in Purchased Power and Fuel expense. As derivative instruments are settled, sales are recorded in Operating Revenues, with purchases, natural gas swaps and futures recorded in Purchased Power and Fuel expense. PGE records the non-physical settlement of non-trading electricity derivative activities on a net basis in Purchased Power and Fuel expense, in accordance with EITF 03-11.

Special accounting for qualifying hedges allows gains and losses on a derivative instrument to be recorded in OCI until they can offset the related results on the hedged item in the Income Statement. As discussed below, the effects of changes in fair value of certain derivative instruments entered into to hedge the company's future non-trading retail resource requirements are subject to regulation and are therefore deferred pursuant to SFAS No. 71.

PGE discontinued its electricity and natural gas trading (non-retail) activities in early 2005. Unrealized and realized gains and losses on the settlement of all derivative instruments related to such activities were reported on a net basis, as required by EITF 02-3.

Non-Trading Activities

PGE participates in the wholesale marketplace in order to balance its supply of power to meet the needs of its retail customers, manage risk, and administer its current long-term wholesale contracts. Such activities include power purchases and sales resulting from economic dispatch decisions for its own generation, which allows PGE to secure reasonably priced power for its customers. Most of PGE's non-trading wholesale sales have been to utilities and power marketers and have been predominantly short-term. In this process, PGE may net purchases and sales with the same counterparty rather than simultaneously receiving and delivering physical power. These net transactions are also referred to as "book outs." Only the net amount of those purchases or sales required to fulfill retail and wholesale obligations are physically settled.

SFAS No. 133 requires unrealized gains and losses on derivative instruments that do not qualify for either the normal purchase and normal sale exception or hedge accounting to be recorded in earnings in the current period. Rates approved by the OPUC are based on a valuation of all the Company's energy resources, including derivative instruments existing on October 27, 2005 that will settle during the 12-month period from January 1, 2006 to December 31, 2006. Such valuation was based on forward price curves in effect on November 8, 2005 for electricity and natural gas. The timing difference between the recognition of gains and losses on certain derivative instruments and their realization and subsequent recovery in rates is recorded as a regulatory asset or regulatory liability to reflect the effects of regulation under SFAS No. 71. As these contracts are settled, the regulatory asset or regulatory liability is reversed. However, as there is currently no power cost adjustment mechanism in effect for 2006, unrealized gains and losses related to new derivatives not included in rates that will settle in 2006, and changes in fair value of financial derivatives used to set rates, are not deferred as regulatory assets or regulatory liabilities.

The following table indicates unrealized gains and losses recorded in earnings for the years indicated (in millions):

	2005	2004	2003
Non-Trading Activities			
Net unrealized gains	\$ 41	\$ 6	\$ 29
SFAS No. 71 regulatory (liability) asset	(37)	(22)	(16)
Net unrealized gains (losses)	<u>\$ 4</u>	<u>\$ (16)</u>	<u>\$ 13</u>

The following table indicates derivative activities from cash flow hedges recorded in OCI for the years indicated (in millions):

	2005	2004	2003
Derivative Activities Recorded in OCI			
Other unrealized holding net gains arising during the period	\$ 46	\$ 20	\$ 14
Reclassification adjustment for contract settlements included in net income	7	(10)	(4)
Reclassification adjustment in net income due to discontinuance of cash flow hedges (*)	(2)	-	(15)
Reclassification of unrealized (gains) losses to SFAS No. 71 regulatory (liability) asset	<u>(48)</u>	<u>(16)</u>	<u>4</u>
Total - Unrealized gains (losses) on derivatives classified as cash flow hedges	<u>\$ 3</u>	<u>\$ (6)</u>	<u>\$ (1)</u>

(*) Due to the probability that the original forecasted transactions will not occur.

Hedge ineffectiveness from cash flow hedges was not material in 2005, 2004, and 2003. As of December 31, 2005, the maximum length of time over which PGE is hedging its exposure to such transactions is approximately 69 months. The Company estimates that of the \$65 million of net unrealized gains in OCI at December 31, 2005, \$55 million will be reclassified into earnings within the next twelve months (offset by a \$55 million SFAS No. 71 regulatory liability), and \$10 million will be reclassified over the remaining 57 months (fully offset by a SFAS No. 71 regulatory liability).

Trading Activities

Prior to 2005, PGE utilized forward, swap, option, and futures contracts to participate in electricity and natural gas markets for non-retail purposes. In early 2005, PGE discontinued its trading activities for non-retail purposes, with existing trading transactions settled by December 31, 2005. Such activities were not reflected in PGE's retail prices.

As indicated above, all unrealized and realized gains and losses associated with "energy trading activities" are reported on a net basis for all periods presented. The following tables indicate unrealized and realized gains and losses on electricity and natural gas trading activities and transaction volumes for electricity trading contracts that settled in the years indicated:

	2005	2004	2003
Trading Activities (In Millions)			
Unrealized Gain (Loss)	\$ (1)	\$ 1	\$ 1
Realized Gain	1	-	1
Net Gain in Operating Revenues	<u>\$ -</u>	<u>\$ 1</u>	<u>\$ 2</u>

Electricity Trading - MWhs (thousands)

Sales	815	9,699	13,551
Purchases	815	9,699	13,551

Note 9 - Jointly Owned Plant

At December 31, 2005, PGE had the following investments in jointly owned generating plants (dollars in millions):

Facility	Location	Fuel	PGE Interest		Plant In Service	Accumulated Depreciation (*)
			Percent	MW Capacity		
Boardman	Boardman, OR	Coal	65.00	380	\$417	\$250
Colstrip 3 and 4	Colstrip, MT	Coal	20.00	296	469	288
Pelton/Round Butte	Madras, OR	Hydro	66.67	298	113	41

(*) Excludes "Asset Retirement Obligations" and "Accumulated Asset Retirement Removal Costs."

Above amounts represent PGE's share of each jointly owned plant, with the Company's share of both direct expenses and utility plant costs included in its financial statements. Each joint owner of the plants has provided its own financing. PGE operates Boardman and Pelton/Round Butte; PPL Montana, LLC operates Colstrip 3 and 4.

Note 10 - Legal and Environmental Matters

Legal Matters

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

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

While the petitions for review of the 1998 Court of Appeals decision were pending at the Oregon Supreme Court, in 2000, PGE, CUB, and the staff of the OPUC entered into agreements to settle the litigation related to PGE's recovery of, and return on, its investment in the Trojan plant. URP did not participate in the settlement. The settlement, which was approved by the OPUC in September 2000, allowed PGE to remove from its balance sheet the remaining before-tax investment in Trojan of approximately \$180 million at September 30, 2000, along with several largely offsetting regulatory liabilities. The largest of such amounts consisted of before-tax credits of approximately \$79 million in customer benefits related to the previous settlement of power contracts with two other utilities and the approximately \$80 million remaining credit due customers under terms of PGC's 1997 merger with Enron. The settlement also allows PGE recovery of approximately \$47 million in income tax benefits related to the Trojan investment which had been flowed through to customers in prior years; such amount is being recovered from PGE customers, with no return on the unamortized balance, over an approximate five-year period that began in October 2000. At December 31, 2005, the remaining balance to be collected was approximately \$1 million. After offsetting the investment in Trojan with these credits and prior tax benefits, the remaining Trojan regulatory asset balance of approximately \$5 million (after tax) was expensed. As a result of the settlement, PGE's investment in Trojan is no longer included in rates charged to customers, either through a return of or a return on that investment. Authorized collection of Trojan decommissioning costs is unaffected by the settlement agreements or the OPUC orders.

The URP filed a complaint with the OPUC challenging the settlement agreements and the Commission's September 2000 order. In March 2002, after a full contested case hearing, the OPUC issued an order (2002 Order) denying all of URP's challenges, and approving the accounting and ratemaking elements of the 2000 settlement. URP appealed the 2002 Order to the Marion County, Oregon Circuit Court. On November 7, 2003, the Marion County Circuit Court issued an opinion remanding the case to the OPUC for action to reduce rates or order refunds. The opinion does not specify the amount or timeframe of any reductions or refunds. PGE and the OPUC have filed appeals to the Oregon Court of Appeals.

In a separate legal proceeding, two class action suits were filed in Marion County Circuit Court against PGE on January 17, 2003 on behalf of two classes of electric service customers. One case seeks to represent current PGE customers that were customers during the period from April 1, 1995 to October 1, 2000 (Current Class) and the other case seeks to represent PGE customers that were customers during the period from April 1, 1995 to October 1, 2000, but who are no longer customers (Former Class). The suits seek damages of \$190 million for the Current Class and \$70 million for the Former Class, as a result of the inclusion of a return on investment of Trojan in the rates PGE charges its customers. On April 28, 2004, the plaintiffs filed a Motion for Partial Summary Judgment and on July 30, 2004, PGE also moved for Summary Judgment in its favor on all of Plaintiff's claims. On December 14, 2004, the Judge granted the Plaintiff's motion for Class Certification and Partial Summary Judgment and denied PGE's motion for Summary Judgment. PGE filed a proposed order certifying the issue for an interlocutory appeal. An order rejecting the proposed order was entered on February 1, 2005. On March 3, 2005 and March 29, 2005, PGE filed two Petitions for an Alternative Writ of Mandamus with the Oregon Supreme Court, asking the Court to take jurisdiction and command the trial Judge to dismiss the complaints or to show cause why they should not be dismissed and seeking to overturn the Class Certification. On May 3, 2005, the Oregon Supreme Court granted both Petitions. Briefing and oral arguments have been completed and a decision is pending.

On March 3, 2004, the OPUC re-opened three dockets in which it had addressed the issue of a return on PGE's investment in Trojan, including the 1995 Order and 2002 Order related to the settlement of 2000.

On August 31, 2004, the administrative law judge issued an Order (Scoping Order) defining the scope of the proceedings necessary to comply with the Marion County Circuit Court orders remanding this matter to the OPUC. On October 18, 2004, the OPUC affirmed the Scoping Order. On December 20, 2004, the URP and Class Action Plaintiffs filed an application with the OPUC for reconsideration of the Scoping Order. On February 11, 2005, the OPUC denied reconsideration. On April 18, 2005, URP and Linda K. Williams filed a complaint against the OPUC in Marion County Circuit Court challenging the OPUC's affirmation of the Scoping Order. The OPUC filed a motion to dismiss the complaint, and on September 21, 2005, the Marion County Circuit Court granted the OPUC's motion. Hearings in the first phase of the OPUC proceeding have been held and a decision is pending.

On February 14, 2005, PGE received a Notice of Potential Class Action Lawsuit for Damages and Demand to Rectify Damages from counsel representing Frank Gearhart, David Kafoury and Kafoury Brothers, LLC (Potential Plaintiffs) stating that Potential Plaintiffs intend to bring a class action lawsuit against the Company. Potential Plaintiffs allege that for the period from October 1, 2000 to the present, the Company's electricity rates have included unlawful charges for a return on investment in Trojan in an amount in excess of \$100 million. Under Oregon law, there is no requirement as to the time the lawsuit must be filed following the 30-day notice period. No action has been filed to date.

Management cannot predict the ultimate outcome of the above matters. However, it believes these matters will not have a material adverse impact on the financial condition of the Company, but may have a material impact on the results of operations and cash flows for a future reporting period. No reserves have been established by PGE for any amounts related to this issue.

Multnomah County Business Income Taxes - In January 2005, David Kafoury and Kafoury Brothers, LLC filed a class action lawsuit in Multnomah County Circuit Court against PGE on behalf of all PGE customers who were billed on their electric bills and paid amounts for Multnomah County Business Income Taxes (MCBIT) after 1996. The plaintiffs alleged that during the period 1997 through the third quarter 2004, PGE collected in excess of \$6 million from its customers for MCBIT that was never paid to Multnomah County. The charges were billed and collected under OPUC rules that allow utilities to collect taxes imposed by the county. As a member of Enron's consolidated income tax return, PGE paid the tax it collected to Enron. The plaintiffs sought judgment against PGE for restitution of MCBIT collected from customers plus interest, recoverable costs, and reasonable attorney fees. The plaintiffs filed an amended complaint on February 25, 2005, adding claims for fraud, unjust enrichment, conversion, statutory violations, and seeking punitive damages.

On May 23, 2005, the Court granted PGE's motion for a stay for all purposes until the OPUC's issuance of a declaratory ruling in response to questions by PGE as to whether OPUC rules authorized PGE collections of the MCBIT and whether any refunds to customers were controlled by an OPUC three-year limitation for billing adjustments. On October 5, 2005, the OPUC issued an order that determined that Commission rules authorized PGE collections of the MCBIT from Multnomah County customers but did not require that PGE calculate them in any particular way. Because the OPUC did not find that PGE had violated its rule, the Commission did not answer whether its three-year limitation on billing adjustments applied.

On December 28, 2005, the parties agreed to a settlement by which PGE will make refunds and payments totaling \$10 million, inclusive of interest and plaintiffs' attorney fees, costs, and expenses as approved by the Court's final order. The settlement includes no admission of liability or wrongdoing by PGE. Distribution to customers is limited to amounts collected during the period 1999 through 2005. PGE established a reserve of \$10 million in 2005 related to the settlement. The settlement is subject to final approval by the Multnomah County Circuit Court following a hearing currently scheduled for late July 2006.

Complaint and Application for Deferral-Income Taxes - On October 5, 2005, the URP and Ken Lewis (Complainants) filed a Complaint with the OPUC alleging that, since September 2, 2005 (the effective date of Oregon Senate Bill 408), PGE's rates are not just and reasonable and are in violation of Senate Bill 408 because they contain approximately \$92.6 million in annual charges for state and federal income taxes that are not being paid to any government. The Complaint requests that the OPUC order the creation of a deferred account for all amounts charged to ratepayers since September 2, 2005 for state and federal income taxes, less amounts actually paid by or on behalf of PGE to the federal and state governments for income taxes.

Also on October 5, 2005, the Complainants filed an Application for Deferred Accounting with the OPUC, claiming that PGE is charging ratepayers \$92.6 million annually for federal and state income taxes that is not being paid, and that such charges are not fair, just and reasonable. The Application for Deferred Accounting requests that revenue due to the estimated PGE liabilities for federal and state income taxes, less any amounts of federal and state income taxes paid by PGE or on behalf of PGE, be deferred for later incorporation in rates.

On December 27, 2005, the OPUC issued a Joint Ruling to hold the Complaint and Deferred Accounting application in abeyance pending rehearing of an order previously issued by the OPUC in a rate proceeding involving another Oregon electric utility. Management cannot predict the ultimate outcome of these matters or estimate any potential loss.

Union Grievances - In November 2001, grievances were filed by several members of the International Brotherhood of Electrical Workers Local 125 (IBEW), the bargaining unit representing PGE's union workers, alleging that losses in their pension/savings plan were caused by Enron's manipulation of its stock. The grievances, which do not specify an amount of claim, seek binding arbitration. PGE filed for relief in Multnomah County Circuit Court seeking a ruling that the grievances are not subject to arbitration. On August 14, 2003, the Court granted PGE's motion for summary judgment, finding that the grievances are not subject to arbitration. A final judgment was entered on October 6, 2003. On October 22, 2003, the IBEW appealed the decision to the Oregon Court of Appeals. Both the U.S. District Court and the Bankruptcy Court approved the settlement of the class action litigation styled In re Enron Corp. Securities Derivative & "ERISA" Litigation, Pamela M. Tittle, et al, v. Enron Corp., et al, Civil Action No. H-01-3913, U.S. District Court for the Southern District of Texas, Houston Division (Tittle Action). On September 13, 2005, the U.S. District Court entered a Bar Order in the Tittle Action, which specifically bars all claims arising out of this case, including the IBEW grievance proceeding. On October 18, 2005, at the request of the Oregon Court of Appeals, PGE filed a response memorandum in which PGE argued that the Bar Order makes the grievance moot. A decision is pending. Management cannot predict the ultimate outcome of this matter or estimate any potential loss.

Environmental Matters

Harborton - A 1997 investigation by the Environmental Protection Agency (EPA) of a 5.5 mile segment of the Willamette River known as the Portland Harbor revealed significant contamination of sediments within the harbor. Based upon analytical results of the investigation, the EPA included the Portland Harbor on the federal National Priority List pursuant to the federal Comprehensive Environmental Response, Compensation, and Liability Act (Superfund). In December 2000, PGE received a "Notice of Potential Liability" regarding its Harborton Substation facility and was included, along with sixty-eight other companies, on a list of Potentially Responsible Parties (PRPs) with respect to the Portland Harbor Superfund Site.

Also in 2000, PGE agreed with the Oregon Department of Environmental Quality (DEQ) to perform a voluntary remedial investigation of its Harborton Substation site to confirm whether any hazardous substances had been released from the substation property into the Portland Harbor sediments. In February 2002, PGE submitted its final investigative report to the DEQ, indicating that the voluntary investigation demonstrated that there is no likely present or past source or pathway for release of hazardous substances to surface water or sediments in the Portland Harbor Superfund Site at or from the Harborton Substation site. Further, the voluntary investigation demonstrated that the site does not present a high priority threat to present and future public health, safety, welfare, or the environment. The DEQ submitted the final investigative report to the EPA and, in a May 18, 2004 letter, the EPA stated that "based on the summary information provided by DEQ and the limited data EPA has at this stage in its process, EPA agrees at this time, that this site does not appear to be a current source of contamination to the river." Management believes that the Company's contribution to the sediment contamination, if any, from the Harborton Substation site would qualify it as a de minimis PRP.

Sufficient information is currently not available to determine either the total cost of investigation and remediation of the Portland Harbor or the liability of PRPs, including PGE. Management cannot predict the ultimate outcome of this matter or estimate any potential loss. However, it believes this matter will not have a material adverse impact on the Company's financial statements.

Harbor Oil - Harbor Oil, Inc. (Harbor Oil), located in north Portland, was utilized by PGE to process used oil from the Company's power plants and electrical distribution system from at least 1990 until 2003. Harbor Oil is also utilized by other entities for the processing of used oil and other lubricants.

In 1974 and 1979, major oil spills occurred at the Harbor Oil site that impacted an approximate two acre area. Elevated levels of contaminants, including metals, pesticides, and polychlorinated biphenyl's (PCBs), have been detected at the site. On September 29, 2003, following investigation and site assessment by the EPA, Harbor Oil was included on the federal National Priority List as a federal Superfund site.

PGE received a Special Notice Letter for Remedial Investigation/Feasibility Study from the EPA, dated June 27, 2005, in which the Company was named as one of fourteen PRPs with respect to the Harbor Oil site. The letter starts a period for PRPs to participate in negotiations with the EPA to reach a settlement to conduct or finance a Remedial Investigation and Feasibility Study of the Harbor Oil site. Discussions among the EPA and the PRPs, including PGE, have commenced.

Sufficient information is currently not available to determine either the total cost of investigation and remediation of the Harbor Oil Site or the liability of PRPs, including PGE. Management cannot predict the ultimate outcome of this matter. However, it believes this matter will not have a material adverse impact on the Company's financial statements.

Other - In October 2003, PGE agreed with the DEQ to provide cost recovery for oversight of a voluntary investigation and/or potential cleanup of petroleum products at another Company site that is upland from the Portland Harbor Superfund Site. The site investigation has been completed and a report was submitted to the DEQ in August 2005. The report concludes that fuel and related contaminants have not migrated to the Willamette River from the site. The DEQ has stated that it is satisfied with the report. PGE management considers any material liability related to this matter to be remote.

Note 11 - Asset Retirement Obligations

SFAS No. 143, Accounting for Asset Retirement Obligations (ARO), which was adopted on January 1, 2003, requires the recognition of AROs, measured at estimated fair value, for legal obligations related to dismantlement and restoration costs associated with the retirement of tangible long-lived assets in the period in which the liability is incurred. Upon initial recognition of AROs that are measurable, the probability weighted future cash flows for the associated retirement costs, discounted using a credit-adjusted risk-free rate, are recognized as both a liability and as an increase in the capitalized carrying amount of the related long-lived assets. Due to the long lead time involved, a market-risk premium cannot be determined for inclusion in future cash flows. Capitalized asset retirement costs are depreciated over the life of the related asset, with accretion of the ARO liability classified as an operating expense. On the Statement of Income, amounts are included in Depreciation and Amortization expense for Utility plant and Other Income (Deductions) for Other property.

FASB Interpretation No. 47 (FIN 47), Accounting for Conditional Asset Retirement Obligations - an interpretation of FASB Statement No. 143, was adopted on December 31, 2005. FIN 47 clarifies that the term "conditional asset retirement obligation," as used in SFAS No. 143, refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. An entity is required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated, even though uncertainty exists about the timing and/or method of settlement.

Regulation - Pursuant to regulation, AROs of rate-regulated long-lived assets are included in depreciation expense allowed in rates charged to customers. Any differences in the timing of recognition of costs for financial reporting and ratemaking purposes are deferred as a regulatory asset or regulatory liability under SFAS No. 71. PGE expects any changes in estimated AROs to be incorporated in future rates. Substantially all significant AROs are included in rate regulation.

Asset Retirement Obligations

SFAS 143 - Upon adoption of SFAS No. 143 at January 1, 2003, PGE recorded AROs of \$15 million for utility plant and \$9 million for other property and adjusted the ARO for the Trojan Plant to \$121 million. The ARO associated with decommissioning of the Trojan plant was recorded on a nominal dollar basis at the time of the plant's abandonment in 1993, with costs to be recovered through regulation recorded as a regulatory asset. Upon the adoption of SFAS No. 143, the regulatory asset and the related ARO for decommissioning of the Trojan plant were reduced by \$55 million to adjust the balances to an estimated fair value as required by SFAS No. 143.

The \$11 million transition adjustment for rate-regulated utility plant, consisting of the Boardman and Colstrip Units 3 and 4 coal plants, the Beaver and Coyote Springs gas turbine plants, and the Bull Run hydro project, was deferred as a regulatory liability pursuant to SFAS No. 71. In addition, PGE recorded a \$4 million after-tax gain in earnings from the cumulative effect of a change in accounting principle related to other property. This transition adjustment represents a difference in using a straight-line amortization vs. accretion methodology under SFAS No. 143.

FIN 47 - A \$2 million transition adjustment was recorded as of December 31, 2005 for rate-regulated utility plant resulting from the application of FIN 47, consisting of conditional asset retirement obligations for pole disposal, mercury vapor light disposal, asbestos remediation, PCB disposal, underground storage tank removal, and other miscellaneous disposal costs. The transition adjustment represents a difference in using a straight-line amortization vs. accretion methodology under SFAS No. 143. The \$2 million transition adjustment was fully offset by adjustments to regulatory liabilities pursuant to SFAS No. 71.

The following presents the effects to the balances and activities in AROs for the years indicated (in millions):

	For Year Ended December 31,		
	2005	2004	2003
Beginning Balance	\$ 120	\$ 129	\$ 145
Activity			
AROs incurred	2	-	-
Expenditures	(4)	(17)	(21)
Accretion	6	6	6
Revisions	10	2	(1)
Ending Balance	<u>\$ 134</u>	<u>\$ 120</u>	<u>\$ 129</u>

Unrecognized Asset Retirement Obligations

PGE has certain tangible long-lived assets for which AROs are not measurable. An ARO will be required to be recorded when circumstances change. The assets that may require removal when the plant is no longer in service include the Oak Grove hydro project and transmission and distribution plant located on public right-of-ways and on certain easements. Management believes that these assets will be used in utility operations for the foreseeable future.

Note 12 - Trojan Nuclear Plant

Plant Shutdown and Fuel Storage - In 1993, PGE ceased commercial operation of Trojan, in which the Company has a 67.5% ownership share. Since plant closure, PGE has committed itself to a safe and economical transition toward a decommissioned plant. In May 2005, following completion of radiological decommissioning and approval of the NRC, the plant's operating license was terminated. Spent nuclear fuel is stored in the Independent Spent Fuel Storage Installation (ISFSI), an NRC-approved interim dry storage facility that houses the fuel at the plant site until permanent off-site storage is available.

Decommissioning - The Trojan decommissioning plan includes an estimate of PGE's cost to decommission the plant. The original cost estimate, which was based upon a site-specific engineering study, is periodically updated by PGE. In 2005, previous cost estimates were revised to reflect changes in the timing of decommissioning activities, due primarily to a delay in the completion of a permanent spent fuel storage facility and acceleration of the demolition of major plant structures. At December 31, 2005, the asset retirement obligation, measured at estimated fair value in accordance with SFAS No. 143, is \$107 million. (See Note 11, Asset Retirement Obligations, for further information).

ASSET RETIREMENT OBLIGATION (ARO) (In Millions)

Balance, 12/31/04	\$ 96
2005 Expenditures	(4)
2005 Accretion	5
2005 Estimate Revisions	10
Balance, 12/31/05	<u>\$ 107</u>
Total expenditures through 12/31/05	<u>\$ 210</u>

Remaining decommissioning activities consist of demolition of the existing structures, operation of the ISFSI to the year 2023, and decommissioning of the ISFSI. Final site restoration activities are anticipated to begin in 2023 after PGE completes shipment of spent fuel to a United States Department of Energy (USDOE) facility (see "Nuclear Fuel Disposal and Cleanup of Federal Plants" below).

DECOMMISSIONING TRUST ACTIVITY (In Millions)

	<u>2005</u>	<u>2004</u>
Beginning Balance	\$ 22	\$ 35
<u>Activity</u>		
Contributions	14	14
Earnings	1	1
Disbursements	(6)	(28)
Ending Balance	<u>\$ 31</u>	<u>\$ 22</u>

PGE's current retail prices include recovery of \$14 million annually through 2011 for decommissioning costs; an equal amount is recorded in amortization expense. These amounts are deposited in a trust fund, which is limited to reimbursing PGE for activities covered in Trojan's decommissioning plan. Funds are withdrawn as required to cover general decommissioning costs and operation of the ISFSI.

Decommissioning trust funds are invested in a diversified portfolio of fixed income securities. Year-end balances are valued at market. Earnings on the trust fund are used to reduce decommissioning costs collected from customers. PGE expects any future changes in estimated decommissioning costs to be incorporated in future revenues collected from customers.

Nuclear Fuel Disposal and Cleanup of Federal Plants - PGE has contracted with the USDOE for permanent disposal of spent nuclear fuel in federal facilities and paid for such services, based on Trojan's generation, during the period of plant operation. The availability of an off-site repository for the permanent storage of radioactive waste would allow PGE to remove spent nuclear fuel from the ISFSI and allow final decommissioning and release of the ISFSI site for unrestricted use. Significant delays, however, are expected in the USDOE acceptance schedule for spent fuel from domestic utilities, with no federal repository expected to be available until at least 2010.

In 2002, the USDOE formally recommended Yucca Mountain, Nevada as the nation's first long-term geologic (underground) repository for high-level radioactive waste produced in the United States. The proposed location is based on the conclusions of scientific studies of the site, conducted over 20 years, which support a finding of suitability, as mandated by the Nuclear Waste Policy Act and various regulations of the NRC, USDOE, and the EPA. The House and Senate approved the site and in 2002, President Bush signed the Yucca Mountain resolution into law. Lawsuits have been filed objecting to the recommendation of Yucca Mountain as a nuclear waste repository. Based upon updated information received from the USDOE regarding the acceptance of spent nuclear fuel from Trojan, PGE has extended its projection for the final shipment of spent fuel from 2018 to 2023. The USDOE has not yet submitted to the NRC the required application for an operating license for the repository. Further delays may make it difficult for PGE to move its spent nuclear fuel, currently contained in the ISFSI, to permanent underground storage by 2023.

In 2004, the co-owners of Trojan (PGE, Eugene Water & Electric Board, and PacifiCorp) filed a complaint against the USDOE in the U.S. Court of Federal Claims for failure to accept spent nuclear fuel by January 31, 1998, as required by the Standard Form Contract. The plaintiffs paid for permanent disposal services during the period of plant operation (in the total amount of \$109 million) and have met all other conditions precedent. Damages sought are in excess of \$200 million.

The Energy Policy Act of 1992 provided for the creation of a Decontamination and Decommissioning Fund to finance the cleanup of USDOE gas diffusion plants, with funding provided by both domestic nuclear utilities and the federal government. Contributions are based upon each utility's share of total enrichment services purchased by all domestic utilities prior to enactment of the legislation. PGE's \$17 million share of the total funding requirement, based on Trojan's 1.1% usage of total industry enrichment services, is paid in annual installments that began in 1993, with the final payment due in late-2006.

Security Requirements - In response to the terrorist attacks of September 11, 2001, the NRC issued interim compensatory security measures for a generalized high-level threat environment at closed nuclear reactors that are in the decommissioning process and at ISFSIs. The new requirements are expected to remain in effect until the NRC determines that the level of threat has diminished, or that other security changes are needed. The NRC issued additional security orders to all operating reactors in 2003 that require operating plants to update their defensive strategies to counter a highly organized attack. It is possible that corresponding similar orders (limited in scope) will eventually be issued to the Trojan ISFSI. Until NRC requirements associated with any new orders are determined, any implementation costs (including their impact on the Trojan decommissioning cost estimate and related funding requirements) are not determinable. However, as any new security requirements are evaluated, any additional costs will be determined and decommissioning cost estimates revised as necessary.

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

participation in the secondary financial protection pool covering losses in excess of \$300 million at other nuclear plants. The NRC has also reduced the required primary nuclear insurance coverage for Trojan to \$100 million and has allowed PGE to self-insure for on-site decontamination related to spent nuclear fuel stored in the ISFSI. PGE continues to insure non-contamination property, in the amount of \$25 million, under the Company's "All Risk" property insurance on the Trojan plant.

Trojan ISFSI Pollution Control Tax Credits - PGE received final certification from the Oregon Environmental Quality Commission (OEQC) related to \$21.1 million in Oregon pollution control tax credits that were generated from PGE's investment in the ISFSI. The OEQC rules require that the tax credits be spread over a ten-year period, beginning in 2004. Accordingly, PGE records a regulatory liability to defer the utilization of these tax credits for future refund to customers.

Note 13 - Related Party Transactions

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

	December 31, 2005	December 31, 2004
Receivables from affiliated companies		
Enron Subsidiaries:		
Portland General Holdings, Inc.		
Accounts Receivable ^(a)	\$ -	\$ 5
Allowance for Uncollectible Accounts ^(a)	-	(1)
PGH II and its subsidiary		
Accounts Receivable ^(a)	-	1
Allowance for Uncollectible Accounts ^(a)	-	(1)
Payables to affiliated companies		
Enron Corp:		
Accounts Payable ^(b)	4	4
Income Taxes Payable ^(c)	25	21

^(a) Included in Accounts and notes receivable on the Consolidated Balance Sheets

^(b) Included in Accounts payable and other accruals on the Consolidated Balance Sheets

^(c) Included in Accrued taxes on the Consolidated Balance Sheets

For the Years Ended December 31	2005	2004	2003
Expenses billed from affiliated companies			
Enron Corp:			
Intercompany services ^(a)	\$ 7	\$ 28	\$ 34
Expenses billed to affiliated companies			
PGH II and its subsidiaries:			
Intercompany services ^(a)	-	1	1
Interest, net from affiliated companies			
Enron Corp:			
Interest expense ^(b)	-	-	(8)

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

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

Income Taxes Payable - As a member of Enron's consolidated income tax return, PGE made payments to Enron for the Company's income tax liabilities. The \$25 million income taxes payable to Enron at December 31, 2005 represents a net current income taxes payable for the fourth quarter of 2005 that was paid to Enron in January 2006. During 2005, PGE paid \$85 million to Enron for income taxes payable, consisting of \$21 million outstanding at December 31, 2004 related to the fourth quarter of 2004 and \$64 million for the first nine months of 2005.

Intercompany Receivables and Payable - As part of its continuing operations, PGE bills affiliates for various services provided by the Company. These include services provided by PGE employees, as well as other corporate services. In addition, Enron passes through PGE's share of costs related to certain insurance coverage. Transactions with affiliates are subject either to approval of, or

confirmation filing requirements with, the OPUC. Under OPUC regulations, services provided to affiliates by PGE are charged at the higher of cost or market, while affiliated services received by PGE are charged at the lower of cost or market.

Affiliate transactions were also regulated by the SEC until February 8, 2006, when PUHCA 1935 was repealed by the Energy Policy Act of 2005 and replaced with the PUHCA 2005. Certain transactions are now regulated by the FERC, which obtains access to holding company books and records and may determine cost allocations in certain affiliate transactions. PGE does not expect that PUHCA 2005 will have a material impact on the Company's operations or financial results.

Enron - Beginning January 1, 2005, administration of the medical/dental benefit and retirement savings plans was returned to PGE from Enron; as a result, Enron no longer passes through costs to PGE for these services. In 2005, Enron billed PGE approximately \$7 million for insurance coverage and costs related to the resolution of certain employee benefit plan matters (see below). In 2004, Enron billed PGE approximately \$28 million, consisting of \$25 million for medical/dental benefits and retirement savings plan matching and \$3 million for insurance coverage. In 2003, Enron billed PGE approximately \$34 million, consisting of \$20 million for medical/dental benefits and retirement savings plan matching, \$1 million for insurance coverage, and \$13 million for corporate overhead costs.

Enron has continued to incur costs related to the resolution of issues associated with the bankruptcy and litigation with regards to certain employee benefit plans in which PGE employees previously participated. Enron billed PGE for a portion of these costs in 2004 and 2005 as work continued toward resolution of the issues. At December 31, 2005, PGE had \$4 million payable to Enron related to these costs, including \$1 million incurred in 2005. At December 31, 2004, PGE had \$4 million payable to Enron related to employee benefits.

Portland General Holdings, Inc. - On June 27, 2003, PGH, a wholly owned subsidiary of Enron located in Portland, filed to initiate bankruptcy proceedings under the federal Bankruptcy Code. The PGH filing was procedurally consolidated with the Enron bankruptcy proceeding; however, the Chapter 11 Plan expressly did not pertain to PGH. No PGH subsidiaries are included in the bankruptcy filing. Substantially all assets of PGH were distributed or placed in segregated accounts and, on October 20, 2005, the Bankruptcy Court dismissed PGH's Chapter 11 case.

At December 31, 2004, PGE had outstanding accounts receivable from PGH of \$5 million, comprised of \$4 million related to employee benefit plans and \$1 million for employee and administrative services provided by PGE to PGH in 2002. Based on management's assessment of the realizability of the receivable from PGH, a reserve of \$1 million was recorded as of December 31, 2004. In October 2005, PGE received \$4 million, representing the unreserved amount owed by PGH.

PGH II and its Subsidiary - PGH II, Inc. (PGH II), a wholly owned subsidiary of PGH, is the parent company of Portland General Distribution, LLC (PGDC), a telecommunications company which received services from PGE. PGH II and PGDC were not part of Enron's or PGH's bankruptcy proceedings. At December 31, 2004, PGE had outstanding accounts receivable from PGDC of \$1 million for employee and other administrative services, offset by a \$0.9 million uncollectible reserve. In June 2005, PGDC used the proceeds from an asset sale to pay the unreserved amounts that it owed to PGE.

PGE did not provide or bill PGH II for any services in 2005. In both 2004 and 2003, PGE billed PGH II and its subsidiaries \$1 million for employee and other administrative services.

Following the distribution of new PGE common stock, neither PGH nor PGH II, as wholly owned subsidiaries of Enron, will be affiliates of PGE.

Other Subsidiaries - PGE also provides services to its consolidated subsidiaries, including funding under a cash management agreement and the sublease of office space in the Company's headquarters complex. Intercompany balances and transactions have been eliminated in consolidation.

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

Note 14 - Receivables and Refunds on Wholesale Market Transactions

Receivables - California Wholesale Market

As of December 31, 2005, PGE has net accounts receivable balances totaling approximately \$63 million from the California Independent System Operator (ISO) and the California Power Exchange (PX) for wholesale electricity sales made from November 2000 through February 2001. The Company estimates that the majority of this amount was for sales by the ISO and PX to Southern California Edison Company and Pacific Gas & Electric Company (PG&E).

In March 2001, the PX filed for bankruptcy and in April 2001, PG&E filed a voluntary petition for relief under the provisions of Chapter 11 of the federal Bankruptcy Code. PGE filed a proof of claim in each of the proceedings for all past due amounts. Although both entities have emerged from their bankruptcy proceedings as reorganized debtors, not all claims filed in the proceedings, including those filed by PGE, have been resolved. PGE is continuing to pursue collection of these claims.

Management continues to assess PGE's exposure relative to these receivables. Based upon FERC orders regarding the methodology to be used to calculate refunds and the FERC's indication that potential refunds related to California wholesale sales (see "Refunds on Wholesale Transactions" below) can be offset with accounts receivable related to such sales, PGE has established reserves totaling \$40 million related to this receivable amount. The Company is examining numerous options, including legal, regulatory, and other means, to pursue collection of any amounts ultimately not received through the bankruptcy process.

Refunds on Wholesale Transactions

California

On July 25, 2001, the FERC issued an order establishing the scope of and methodology for calculating refunds for wholesale sales transactions made between October 2, 2000 and June 20, 2001 in the spot markets operated by the ISO and PX. The order established evidentiary hearings to develop a factual record to provide the basis for the refund calculation. Several additional orders clarifying and further defining the methodology have since been issued by the FERC. Appeals of the FERC orders were filed and in August 2002 the U.S. Ninth Circuit Court of Appeals issued an order requiring the FERC to reopen the record to allow the parties to present additional evidence of market manipulation.

Also in August 2002, the FERC Staff issued a report that included a recommendation that natural gas prices used in the methodology to calculate potential refunds be reduced significantly.

In December 2002, a FERC administrative law judge issued a certification of facts to the FERC regarding the refunds, based on the methodology established in the 2001 FERC order rather than the August 2002 FERC Staff recommendation. On March 26, 2003, the FERC issued an order in the California refund case (Docket No. EL00-95) adopting in large part the certification of facts of the FERC administrative law judge but adopting the August 2002 FERC Staff recommendation on the methodology for the pricing of natural gas in calculating the amount of potential refunds. PGE

estimates its potential liability under the modified methodology at between \$40 million and \$50 million, of which \$40 million has been established as a reserve, as discussed above.

Numerous parties, including PGE, filed requests for rehearing of various aspects of the March 26, 2003 order, including the methodology for the pricing of natural gas. On October 16, 2003, the FERC issued an order reaffirming, in large part, the modified methodology adopted in its March 26, 2003 order. PGE does not agree with the FERC's methodology for determining potential refunds, and, on December 20, 2003 the Company appealed the FERC's October 16, 2003 order to the U.S. Ninth Circuit Court of Appeals; several other parties have also appealed the October 16, 2003 order. On May 12, 2004, the FERC issued an order that denied further requests for rehearing of the October 16, 2003 order. Although there continue to be miscellaneous orders issued in the underlying FERC proceeding, the Ninth Circuit Court of Appeals has now begun to hear the numerous appeals. It has bifurcated appeals of the existing cases into two phases. The first considered arguments regarding jurisdictional issues and the permissible scope of refund liability, both in terms of the time frame for which refunds were ordered and the types of transactions subject to refund. Briefing and oral argument have been completed on this first phase. As to the jurisdictional issues, on September 6, 2005, the Court ruled that FERC did not have jurisdiction to order municipal utilities and other governmental entities to make refunds for the sales they had made to the ISO and PX that are the subject of the refund proceeding. The Court has not yet issued a decision on the other issues pending in the first phase, and the Court agreed to defer the rehearing deadline on the jurisdictional issue decision until the remainder of the first phase is decided. The second phase will consider the issues relating to the refund methodology itself. PGE expects that the Court will establish additional phases as the continuing issues remaining before FERC become final and are appealed.

Also on May 12, 2004, the FERC issued a separate order that provided clarification regarding certain aspects of the methodology for California generators to recover fuel costs incurred to generate power that were in excess of the gas cost component used to establish the refund liability. On September 24, 2004, the FERC issued an order that denied requests for rehearing of its May 12, 2004 fuel cost order and also adopted a new methodology to allocate the excess amounts of fuel costs that California generators are permitted to recover. Additional clarifying orders continue to be issued periodically. Under the new allocation methodology of the September 24, 2004 order, PGE could be required to pay additional amounts in those hours when it was a net buyer in California spot markets, thus increasing its net refund liability. PGE does not expect that this order will materially increase the Company's potential refund exposure. Partly as a means of limiting its exposure to additional fuel costs, PGE has opted to become a participant in several settlements filed jointly by large generators and California parties, and approved by the FERC during 2004 and 2005.

In August 2005, PGE joined in a settlement agreement resolving issues relating to the allocation of the wind-up costs of the PX for both past and future periods. The settlement has been approved by the FERC. Although under the agreement PGE will bear certain additional costs associated with PX obligations to conduct and finalize refund calculations, PGE does not expect those costs to be material to its financial statements.

In several of its underlying refund orders, the FERC has indicated that if marketers, such as PGE, believe that the level of their refund liability has caused them to incur an overall revenue shortfall for their sales to the ISO and PX during the refund period, they will be permitted to file a cost study to prove that they should be permitted to recover additional revenues in excess of the mitigated prices in order to cover their costs. By order issued August 8, 2005, FERC provided guidelines regarding the manner in which these studies should be conducted and the principles that should govern their preparation. PGE filed for rehearing of certain aspects of the August 8 order, and, on September 14, it filed its cost recovery study with FERC. The study showed that, pursuant to the principles set forth in the August 8 order and subject to rehearing, PGE's costs to serve the ISO and PX markets exceeded the revenues PGE will receive from those mitigated sales by over \$27 million. By order issued

January 26, 2006, the FERC conditionally accepted PGE's September 14 cost filing, subject to PGE making a compliance filing to eliminate certain costs, to include additional revenues, and to supplement its analysis with additional cost, load, and resource data. On February 10, 2006, PGE submitted a compliance filing with two cases, in the alternative, that incorporated the FERC-required changes. The compliance filing shows a revenue deficit for PGE's sales to the ISO and PX (that is, a reduction to PGE's refund liability) of from approximately \$20 million to approximately \$30 million, depending on the methodology ultimately accepted by the Commission. Third parties have challenged PGE's compliance filing and requested that it be rejected in its entirety or that the cost offset be reduced to zero, and PGE has filed a response to those challenges. The procedure established by the FERC in the January 26 order also required each seller whose cost filing has been accepted to incorporate in its filing final ISO and PX settlement data and to provide its revised filing to the ISO and PX for further processing.

PGE believes that the FERC erred in certain of its findings in the January 26 order, and has filed a request for rehearing as to several issues. Due to the continuing uncertainty related to these matters, PGE has made no adjustment to the \$40 million reserve previously established for the Company's potential liability, as described above.

The FERC has indicated that any refunds PGE may be required to pay related to California wholesale sales (plus interest from collection date) can be offset by accounts receivable (plus interest from due date) related to sales in California (see "Receivables - California Wholesale Market" above). In addition, any refunds paid or received by PGE applicable to spot market electricity transactions on and after January 1, 2001 in California may be eligible for inclusion in the calculation of net variable power costs under the Company's power cost adjustment mechanism in effect at that time. This could further mitigate the financial effect of any refunds made or received by the Company.

Challenge of the California Attorney General to Market-Based Rates - On March 20, 2002, the California Attorney General filed a complaint with the FERC against various sellers in the wholesale power market, alleging that the FERC's authorization of market-based rates violated the Federal Power Act (FPA), and, even if market-based rates were valid under the FPA, that the quarterly transaction reports required to be filed by sellers, including PGE, did not contain the transaction-specific information mandated by the FPA and the FERC. The complaint argued that refunds for amounts charged between market-based rates and cost-based rates during the period October 2, 2000 - June 4, 2002 should be ordered. The FERC denied the challenge to market-based rates and refused to order refunds, but did require sellers, including PGE, to re-file their quarterly reports to include transaction-specific data. The California Attorney General appealed the FERC's decision to the Ninth Circuit Court of Appeals. On September 8, 2004, the Court issued an opinion upholding the FERC's authority to approve market-based tariffs, but also holding that the FERC had the authority to order refunds, if quarterly filing of market-based sales transactions had not been properly made. The Court required the FERC, upon remand, to reconsider whether refunds should be ordered. On October 25, 2004, certain parties filed a petition for rehearing with the Court. In the refund case and in related dockets, the California Attorney General and other California parties have argued that refunds should be ordered retroactively to at least May 1, 2000. Management cannot predict the outcome of these proceedings or whether the FERC will order refunds retroactively to May 1, 2000, and if so, how such refunds would be calculated.

Anomalous Bidding Allegations

By order issued on June 25, 2003, the FERC instituted an investigation into allegations of anomalous bidding activities and practices ("economic withholding") on the part of numerous parties, including PGE. The FERC determined that bids above \$250 per MW in the period from May 1, 2000 through October 2, 2000 may have violated tariff provisions of the ISO and the PX. The FERC required companies that bid in excess of \$250 per MW to provide information on their bids to the FERC investigation staff. PGE responded to the FERC's inquiries and, on May 12, 2004, the FERC

investigation staff issued to PGE a letter terminating the investigation as to the Company without further action. On March 10, 2005, certain California parties filed appeals with the Ninth Circuit Court of Appeals, contesting the FERC's conduct of the investigation of the anomalous bidding allegations and the issuance of the dismissal letters.

Pacific Northwest

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

Management cannot predict the ultimate outcome of the above matters related to wholesale transactions in California and the Pacific Northwest. However, it believes that the outcome will not have a material adverse impact on the financial condition of the Company, but may have a material impact on the results of operations for future reporting periods.

Note 15 - Future Ownership of PGE

Commencing on December 2, 2001, and from time to time thereafter, Enron, along with certain of its subsidiaries, filed to initiate bankruptcy proceedings under Chapter 11 of the federal Bankruptcy Code. Although PGE was not included in the bankruptcy, the common stock of PGE held by Enron is one of the assets of the bankruptcy estate.

Enron's Fifth Amended Joint Plan of Affiliated Debtors Pursuant to Chapter 11 of the United States Bankruptcy Code, dated January 9, 2004 and as thereafter amended and supplemented from time to time (Chapter 11 Plan), became effective on November 17, 2004. The Chapter 11 Plan and the related disclosure statement provide information about the assets that were in the bankruptcy estate, including the common stock of PGE, and how those assets or their proceeds will be distributed to the creditors.

Enron and PGE are moving forward to distribute new PGE common stock to the creditors of Enron and its reorganized debtor subsidiaries (collectively the Debtors) in accordance with the Chapter 11 Plan. Current PGE common stock held by Enron will be cancelled and 62,500,000 shares of new PGE common stock without par value will be distributed over time to the Debtors' creditors that hold allowed claims. PGE will issue at least 30 percent of the new PGE common stock to the Debtors' creditors that hold allowed claims, with the remainder issued to a Disputed Claims Reserve (DCR) where it will be held to be released over time to the Debtors' creditors holding allowed claims in accordance with the Chapter 11 Plan.

The distribution of new PGE common stock has been approved by all required regulatory agencies. If sufficient claims have been resolved in a timely manner to allow at least 30% of the new PGE common stock to be issued to Debtors' creditors, then issuance of new PGE common stock is expected to take place on or about April 3, 2006. Following issuance of the new PGE common stock to the Debtors' creditors and the DCR, PGE will no longer be a subsidiary of Enron.

The registered owner of the new PGE common stock held in the DCR will be the Disbursing Agent associated with the DCR. The Disbursing Agent will oversee the release of new PGE common stock from the DCR to the Debtors' creditors that hold allowed claims. All shares of new PGE common

stock held in the DCR will be voted by the Disbursing Agent at the direction of the Disputed Claims Reserve Overseers (DCRO). The DCRO is currently comprised of those individuals who serve on Enron's Board of Directors.

The OPUC order approving the distribution of new PGE common stock includes 17 conditions that relate to, among other things: maintenance of PGE's financial strength during the conclusion of the Enron bankruptcy process, certain indemnifications for PGE from Enron related to Enron employee benefit plans and taxes, certain service quality measures, and additional direct access options for commercial and industrial customers. The indemnifications are expected to be included in a separation agreement between Enron and PGE, which is expected to be executed at the time of the issuance of new PGE common stock.

On February 10, 2006, the City of Portland appealed the OPUC Order in both the Marion County Circuit Court and the Oregon Court of Appeals. The City filed its appeals in both courts due to the jurisdictional uncertainty created by new Oregon law governing appeals of OPUC decisions. In its appeal to the Circuit Court, the City alleges that the OPUC made its decision on an inadequate record, failed to enter adequate findings in support of its decision, abused the discretion granted it by Oregon law, and based its decision on a statute that constituted an unlawful delegation from the Oregon Legislature. The City requests the OPUC Order be modified, reversed or remanded. In the Court of Appeals filing, the City alleges that it is an aggrieved party and asks for judicial review without further details. On February 23, 2006 the OPUC filed a Motion to Hold Case in Abeyance with the Marion County Circuit Court in order to seek summary determination from the Court of Appeals regarding the proper court to hear the City's appeal. The City and other defendants to the action, including PGE, did not oppose the motion. The Circuit Court has not ruled on this motion.

On February 13, 2006, the URP filed with the OPUC an application for reconsideration of the OPUC Order. The URP requests that the OPUC reconsider its order in light of a new Oregon Statute (Senate Bill 408), governing the rate treatment of income taxes included by Oregon utilities in rates. The URP alleges the stock distribution would allow PGE to deconsolidate for income tax purposes and frustrate future rate benefits Senate Bill 408 would allegedly produce. On February 28, 2006, PGE, CUB, and the OPUC staff filed oppositions to URP's application for reconsideration. Also on February 28, 2006, the City filed in support of URP's application and added new grounds for reconsideration of the OPUC Order. PGE filed in opposition to the City's new grounds for reconsideration on March 13, 2006. The OPUC has 60 days from the filing of an application for reconsideration to act on the application or it is deemed denied.

PGE has filed an original listing application with the New York Stock Exchange for the listing of the new PGE common stock under the ticker symbol POR.

Enron has also indicated that, in accordance with its ongoing efforts to maximize the value of the Enron bankruptcy estate, Enron will continue to consider credible offers to purchase PGE's common stock until the new PGE common stock is distributed. Following distribution of the new PGE common stock, approval of any offer to purchase the new PGE common stock from the DCR will be the responsibility of the DCRO, in accordance with guidelines approved by the Bankruptcy Court.

Note 16 - Restatement of Prior Period Financial Statements

Pension and Other Post Retirement Benefits

Prepaid pension costs of \$78 million and accrued liabilities for other post retirement benefits of \$9 million have been restated to reclassify the balances from current assets (liabilities) to non-current assets (liabilities) on the Consolidated Balance Sheet as of December 31, 2004.

Non-Utility Property - Asset Retirement Obligation

During the financial closing process for the year ended December 31, 2005, PGE determined that a \$20 million liability established in 1997 for estimated future demolition and remediation costs related to tenant leasehold improvements on non-utility land located adjacent to the Company's Sullivan Hydro Plant did not include consideration of salvage values. Inclusion of salvage values would have reduced the recorded liability by \$8 million (to \$12 million) and adjusted related deferred taxes by \$3 million, resulting in a \$5 million increase in the January 1, 2003 balance of retained earnings, from \$488 million (as previously reported) to \$493 million (as restated).

In addition, upon the January 1, 2003 adoption of SFAS No. 143, Accounting for Asset Retirement Obligations, the Company should have further reduced the recorded liability by \$4 million (to its estimated \$8 million fair value) and adjusted related deferred income taxes by \$2 million.

A summary of the significant effects of the above restatements are as follows (in millions):

	<u>Consolidated Statement of Income</u>	
	<u>As Previously Reported</u>	<u>As Restated</u>
<u>For the year ended December 31, 2003</u>		
Cumulative effect of a change in accounting principle, net of related taxes [Previously reported \$(1); Restated \$(3)]	\$ 2	\$ 4
Net Income	58	60

	<u>Consolidated Balance Sheet</u>	
	<u>As Previously Reported</u>	<u>As Restated</u>
<u>As of December 31, 2004</u>		
Prepayments and other ⁽¹⁾	\$ 113	\$ 35
Deferred Charges and Other - Miscellaneous ⁽¹⁾	25	103
Retained earnings ⁽²⁾	637	644
Accounts payable and other accruals ⁽¹⁾	182	173
Deferred income taxes ⁽²⁾	308	313
Accumulated asset retirement obligation ⁽²⁾	16	24
Other - Miscellaneous ⁽¹⁾⁽²⁾	37	26

⁽¹⁾ Pension and Other Post Retirement Benefits

⁽²⁾ Non-Utility Property - Asset Retirement Obligation

In addition, the Company has restated the presentation of the activities within the Nuclear Decommissioning Trust to disclose amounts on a gross basis, rather than on a net basis, in the Consolidated Statements of Cash Flow.

QUARTERLY COMPARISON FOR 2005 AND 2004 (Unaudited)

	<u>March 31</u>	<u>June 30</u>	<u>September 30</u> (In Millions)	<u>December 31</u>	<u>Total</u>
<u>2005</u>					
Operating revenues	\$371	\$333	\$355	\$387	\$1,446
Net operating income (*)	53	32	36	5	126
Net income (loss) (*)	38	16	19	(9)	64
Income (loss) available for Common stock	38	16	19	(9)	64
<u>2004</u>					
Operating revenues	\$395	\$332	\$348	\$379	\$1,454
Net operating income	48	38	20	44	150
Net income	32	22	10	28	92
Income available for Common stock	32	22	10	28	92

(*) On October 22, 2005, the Boardman coal plant was taken out of service for repair of the plant's steam turbine rotor. PGE incurred significant incremental power costs during the fourth quarter to replace the plant's generation, the after-tax effect of which was approximately \$25 million. For further information, see "Boardman Coal Plant - Extended Outage" in Item 7. - "Management's Discussion and Analysis of Financial Condition and Results of Operation."

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

None.

Item 9A. Controls and Procedures

- (a) **Disclosure Controls and Procedures.** Management of the Company, under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the Company's disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of the end of the period covered by this report pursuant to Rule 13a-15(b) under the Exchange Act. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of such period, the Company's disclosure controls and procedures are effective in recording, processing, summarizing and reporting, on a timely basis, the information relating to the Company (including its consolidated subsidiaries) required to be disclosed by the Company in the reports that it files or submits under the Exchange Act and are effective in ensuring that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is accumulated and communicated to the Company's management, including the Company's Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.
- (b) **Changes in Internal Control Over Financial Reporting.** There have not been any changes in the Company's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the fourth quarter that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Item 9B. Other Information

None.

Part III

Item 10. Directors and Executive Officers of the Registrant

Directors of the Registrant ⁽¹⁾

JOHN W. BALLANTINE, age 60

Director since February 1, 2004

Mr. Ballantine has been an active private investor since 1998, when he retired from First Chicago NBD Corporation where he served as Executive Vice President and Chief Risk Management Officer. During his 28-year career with First Chicago, Mr. Ballantine was responsible for International Banking operations, New York operations, Latin American Banking, Corporate Planning, US Financial Institutions business and a variety of trust operations. He also serves on the Boards of DWS Funds, First Oak Brook Bancshares and the Oak Brook Bank, Healthways, Inc., and Prisma Energy International Inc. (an Enron affiliate). Mr. Ballantine served as a director of Enron from May 2002 until November 2004.

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

ROBERT S. BINGHAM, age 57

Director since January 18, 2003

Mr. Bingham has served as a consultant with Kroll Zolfo Cooper, LLC (formerly Zolfo Cooper, LLC) since February 1999. During this time with Kroll Zolfo Cooper, LLC, he has worked on the Enron bankruptcy since February 2002 and served as Interim Chief Financial Officer and Interim Treasurer for Enron from November 2004 until December 16, 2005. He is a certified public accountant and a certified insolvency and restructuring advisor.

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

DAVID A. DIETZLER, age 62

Director since January 25, 2006

Mr. Dietzler has been a CPA for nearly 37 years and retired as a partner of KPMG LLP, a public accounting firm, in 2004. During the past 10 years with KPMG LLP he served in both administrative and client service roles which included serving on the firm's Governance, Nominating and Board Process and Evaluation committees, and was the Pacific Northwest partner in charge of the Audit Practice for KPMG's offices in Anchorage, Boise, Billings, Portland, Salt Lake City and Seattle.

Directors of the Registrant ⁽¹⁾ - Continued

PEGGY Y. FOWLER, age 54

Director since August 14, 1998

Ms. Fowler has served as Chief Executive Officer and President of PGE since April 2000 and was Chair of the Board until January 31, 2004. She served as President from February 1998 until April 2000. She served as Chief Operating Officer of PGE Distribution Operations from November 1996 until February 1998. Previously, she served in various positions with PGE, including Senior Vice President Customer Service and Delivery and Vice President Power Production and Supply. She also serves on the Board of The Regence Group.

Ms. Fowler also served as President of Portland General Holdings, Inc.⁽²⁾ (an Enron affiliate) from March 1999 until June 2003.

MARK B. GANZ, age 45

Director since January 25, 2006

Mr. Ganz is President, Chief Executive Officer and Director of The Regence Group, a parent corporation of various companies offering health, life and disability products and services under the BlueCross and BlueShield trademarks. Prior to his current position, Mr. Ganz served as President and Chief Operating Officer of The Regence Group from 2003 to 2004 and President of Regence BlueCross BlueShield of Oregon from 2001 to 2003. He was Senior Vice President, Chief Legal & Compliance Officer and Corporate Secretary of the Regence Group from 1996 to 2001.

CORBIN A. MCNEILL, JR., age 66

Director since February 1, 2004

Mr. McNeill is Chair of the Board. In 2002, he retired as Chairman and CEO of Exelon Corporation, which was formed in October 2000 by the merger of PECO Energy Company and Unicom Corporation. Prior to the merger, he was Chairman, President and CEO of PECO Energy. Mr. McNeill completed a 20-year career with the U.S. Navy in 1981 and then joined the New York Power Authority as resident manager of the James A. Fitzpatrick nuclear power plant. He also worked at Public Service Electric and Gas Company prior to joining PECO in 1988 as Executive Vice President, Nuclear. He serves on the Boards of Ontario Power Generation, Associated Electric & Gas Services Limited, Owens-Illinois Corporation, and Silver Spring Networks. Mr. McNeill served as a Director of Enron from May 2002 until November 2004.

ROBERT G. MILLER, age 62

Director since January 25, 2006

Mr. Miller is currently Chair of the Board of Rite Aid Corporation, a retail pharmacy chain, which position he has held since 1999. He also served as Chief Executive Officer of Rite Aid Corporation from 2000 to 2003. He was Vice Chairman and Chief Operating Officer of The Kroger Co., a grocery supermarket company, following Kroger's May 1999 acquisition of Fred Meyer, Inc. (a food, drug and general merchandise chain) until December 1999. He served as Chairman of the Board and Chief Executive Officer of Fred Meyer, Inc. from 1991-1998 and Vice Chairman of the Board and Chief Executive Officer from 1998 to May 1999. Mr. Miller also serves as a director of Harrah's Entertainment, Inc. a gaming company owning, operating, and managing casinos; and Nordstrom, Inc. a fashion specialty retailer. He also currently serves as Chair of the Board of Wild Oats Markets, Inc., a natural foods supermarket chain.

Directors of the Registrant ⁽¹⁾ - Continued

M. LEE PELTON, Ph. D., age 55

Director since January 25, 2006

Dr. Pelton was appointed President of Willamette University in July 1999. From 1991 until 1998, he was the dean of Dartmouth College. Prior to 1991, he held faculty and administrative posts at Colgate University and Harvard University. Dr. Pelton serves as the Chairman of the American Council on Education and a member of the Harvard University Board of Overseers and Board of Trustees for the Oregon Health & Science University Foundation. He also serves on the Board of PLATO Learning, Inc.

MARIA M. POPE, age 41

Director since January 25, 2006

Ms. Pope was appointed Vice President-General Manager, Wood Products Division of Pope & Talbot, Inc., a pulp and wood product company, in December 2003. She served as Vice President, Chief Financial Officer and Secretary from 1999 to 2003, and has held various financial positions since joining the Company in 1995. Ms. Pope previously worked for Levi Strauss & Co. and Morgan Stanley & Co., Inc. She currently serves as a member of the Board of Premiera Blue Cross, a nonprofit, independent regional health plan.

ROBERT T. F. REID, age 55

Director since January 25, 2006

Mr. Reid is currently Chair and Corporate Director of British Columbia Transmission Corp., which position he has held since 1999. Mr. Reid served as president of Duke Energy's Canadian operations from 2002 to 2003. Prior to Duke's acquisition of Westcoast Energy in March 2002, he served as Executive Vice President and Chief Operating Officer of Westcoast. Prior to his appointment as Westcoast's Chief Operating Officer in 2001, Mr. Reid held senior executive positions in both the natural gas industry and in government service, including Union Gas Ltd., Westcoast Energy International, Pan-Alberta Gas, Foothills Pipe Lines, and the Independent Petroleum Association of Canada. He also serves as Director of Greystone Capital Management Inc., Investment Saskatchewan Inc., and the Canadian Education Centre Network.

RAYMOND S. TROUBH, age 79

Director since April 1, 2004

Mr. Troubh has been a self-employed financial consultant for more than five years. He also serves on the Boards of Diamond Offshore Drilling, Inc., General American Investors Company, Gentiva Health Services, Inc., Petrie Stores Liquidating Trust (Trustee), Triarc Companies, Inc., and Hollinger International, Inc. Mr. Troubh served as a director of Enron from November 2001 until November 2004 (including Chairman of the Board from November 2002 until November 2004).

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- ⁽¹⁾ As of February 28, 2006. Directors of PGE hold office until the next annual meeting of shareholders or until their respective successors are duly elected and qualified. Robert H. Walls, Jr. resigned as a Director of PGE, effective August 31, 2005.
- ⁽²⁾ Portland General Holdings, Inc. filed for bankruptcy protection on June 27, 2003. PGH's bankruptcy case was dismissed by the Bankruptcy Court on October 20, 2005.

Executive Officers of the Registrant⁽¹⁾

Name	Age	Business Experience
Peggy Y. Fowler Chief Executive Officer and President	54	<p>Appointed to current position on April 1, 2000. Served as President from February 1998 until appointed to current position. Served as Chief Operating Officer of PGE Distribution Operations from November 1996 until February 1998. Previously served in various positions with PGE, including Senior Vice President, Customer Service and Delivery, and Vice President, Power Production and Supply.</p> <p>Ms. Fowler also served as President of Portland General Holdings, Inc.⁽²⁾ (an Enron affiliate) from March 1999 until June 2003.</p>
James J. Piro Executive Vice President, Finance, Chief Financial Officer and Treasurer	53	<p>Appointed to current position on July 25, 2002. Served as Senior Vice President Finance, Chief Financial Officer and Treasurer from May 2001 until appointed to current position. Served as Vice President, Chief Financial Officer and Treasurer from November 2000 until May 2001. Served as Vice President, Business Development from February 1998 until November 2000. Served as General Manager, Planning Support, Analysis and Forecasting, from 1992 until 1998.</p> <p>Mr. Piro also served as Chief Financial Officer and Senior Vice President of Portland General Holdings, Inc.⁽²⁾ (an Enron affiliate) from July 2001 until June 2003.</p>
Arleen N. Barnett Vice President, Administration, Corporate Compliance Officer	54	<p>Appointed to current position on August 2, 2004. Served as Vice President, Human Resources and Information Technology and as Corporate Compliance Officer from May 2001 until appointed to current position. Served as Vice President, Human Resources from February 1998 until May 2001. Served as Manager, Human Resources Operations from 1989 until 1997 and Manager, Generating Division from 1987 to 1989.</p> <p>Ms. Barnett also served as Vice President, Human Resources of Portland General Holdings, Inc.⁽²⁾ (an Enron affiliate) from March 1998 until June 2003.</p>

Executive Officers of the Registrant⁽¹⁾

Name	Age	Business Experience
Carol A. Dillin Vice President, Public Policy	48	Appointed to current position on February 1, 2004. Served as Director of Public Affairs and Corporate Communications from April 1998 until appointed to current position. Served as Manager of Corporate Communications from November 1991 to April 1998.
Stephen R. Hawke Vice President, Customer Service and Delivery	56	Appointed to current position on August 2, 2004. Served as Vice President, System Engineering, Utility Services and Customer Service from October 2003 until appointed to current position. Served as Vice President, System Engineering and Utility Services from July 1997 until October 2003. Served as General Manager, System Planning and Engineering from May 1995 until July 1997. Served as Manager, Response and Restoration from May 1993 until May 1995. Served in a variety of Transmission and Distribution management positions from 1972 to 1993.
Ronald W. Johnson Vice President, Customers and Economic Development	55	Appointed to current position on August 2, 2004. Served as Vice President, Customer Resource Strategy and Generation Engineering from July 2002 until appointed to current position. Served as Vice President, Power Supply, Resource Development and Engineering Services from January 2001 until July 2002. Appointed Vice President, Deputy General Counsel and Assistant Secretary in May 1999. Served as Deputy General Counsel from 1989 until January 2001.
Pamela G. Lesh Vice President, Regulatory Affairs and Strategic Planning	49	Appointed to current position on August 2, 2004. Served as Vice President, Regulatory and Federal Affairs from June 2002 until appointed to current position. Served as Vice President, Public Policy and Regulatory Affairs from May 2001 until June 2002. Served as Vice President, Rates and Regulatory Affairs from December 1998 until May 2001. Served as Vice President, Strategy and Product Management with ConneXt Corp. of Seattle from June 1997 until December 1998. Served as Vice President, Rates and Regulatory Affairs from November 1996 to June 1997. Served as Director, Regulatory Policy from August 1989 to October 1996.

Executive Officers of the Registrant⁽¹⁾

Name	Age	Business Experience
James F. Lobdell Vice President, Power Operations and Resource Planning	47	Appointed to current position on August 2, 2004. Served as Vice President, Power Operations from September 2002 until appointed to current position. Served as Vice President, Risk Management Reporting, Controls and Credit from May 2001 until September 2002. Served as Senior Director of Business Development from July 1999 to May 2001. Served as Vice President, Finance and Administration for FirstPoint Utility Solutions from 1997 to 1998.
Joe A. McArthur Vice President, Distribution	58	Appointed to current position on July 1, 1997. Served as Manager of Western Region from May 1996 until appointed to current position. Served as Manager, System Planning from May 1995 until May 1996. Served as Commercial and Industrial Market Manager from 1993 to 1995.
Douglas R. Nichols Vice President, General Counsel and Secretary	63	Appointed to current position on May 1, 2001. Served as Acting Deputy General Counsel from February 2001 until appointed to current position. Served as Assistant General Counsel from May 1991 to February 2001. Mr. Nichols also served as General Counsel of Portland General Holdings, Inc. ⁽²⁾ (an Enron affiliate) from June 2001 until June 2003.
Stephen M. Quennoz Vice President, Nuclear and Power Supply/ Generation	58	Appointed to current position on August 2, 2004. Served as Vice President, Generation from January 2001 until appointed to current position. Served as Vice President Nuclear and Thermal Operations from October 1998 until January 2001. Joined PGE in 1991 and held the position of Trojan Site Executive and Plant General Manager from 1993 to 1998.

⁽¹⁾ As of February 28, 2006. Officers of PGE are elected for one-year terms or until their successors are elected and qualified.

⁽²⁾ Portland General Holdings, Inc. filed for bankruptcy protection on June 27, 2003. PGH's bankruptcy case was dismissed by the Bankruptcy Court on October 20, 2005.

Audit Committee Financial Expert

The Board has determined that Robert S. Bingham is an "audit committee financial expert" as that term is defined in Item 401(h) of Regulation S-K. However, Mr. Bingham is not "independent" as defined by the applicable listing standards of the New York Stock Exchange.

Code of Ethics

The Company has adopted a code of ethics applicable to PGE's chief executive officer, chief financial officer, chief accounting officer, and controller, which satisfies the definition of "code of ethics" under applicable rules of the SEC. The code of ethics is publicly available on the Company's web site at www.portlandgeneral.com. If the Company makes any substantive amendments to this code, or grants any waivers from a provision of this code to the Company's chief executive officer, chief financial officer, chief accounting officer, or controller, the Company will disclose on the Company's web site the nature of the amendment or waiver, its effective date, and to whom it applies.

Section 16 (a) Beneficial Ownership Reporting Compliance

Section 16 of the Securities Exchange Act of 1934 requires the Company's Directors and Executive Officers to file a Form 3 with the SEC within ten days of becoming a PGE Director or Executive Officer, and thereafter to file various reports concerning holdings of, and transactions in, equity securities of PGE. Copies of those filings must be furnished to the Company. To the best of our knowledge, PGE directors and executive officers complied with all applicable Section 16(a) filing requirements in 2005.

Item 11. Executive Compensation

Summary Compensation Table

The following indicates total compensation earned for the years ended December 31, 2005, 2004 and 2003 by the Chief Executive Officer and the four most highly compensated executive officers of PGE (the "Named Executive Officers").

Name and Principal Position	Year	Annual Compensation		All Other Compensation ⁽²⁾
		Salary ⁽¹⁾	Bonus	
Peggy Y. Fowler	2005	\$383,764	\$370,759	\$ 15,700
Chief Executive Officer	2004	350,004	376,744	13,647
and President	2003	350,004	240,000	413,792
James J. Piro	2005	239,744	115,466	13,519
Executive Vice President, Finance	2004	227,379	138,857	11,933
Chief Financial Officer and Treasurer	2003	215,129	160,000	136,790
Stephen M. Quennoz	2005	206,642	96,844	9,771
Vice President, Nuclear and	2004	193,885	115,815	8,625
Power Supply/Generation	2003	191,411	130,000	8,688
Douglas R. Nichols	2005	209,625	86,068	12,519
Vice President, General Counsel and	2004	193,336	124,730	10,719
Secretary	2003	190,008	138,000	119,716
Stephen R. Hawke	2005	193,500	79,448	10,547
Vice President, Customer Service and	2004	178,336	115,042	9,619
Delivery	2003	175,008	95,000	115,450

⁽¹⁾ Amounts shown include compensation earned by the executive officer, as well as amounts earned but deferred at the election of the officer.

⁽²⁾ Other compensation includes: (i) split dollar term life insurance cost; (ii) company contributions to the PGE Corp Savings Plan (401k) during 2005, Enron Corp. Savings Plan (401k) for 2004-2003 and the Management Deferred Compensation Plan (MDCP); (iii) earnings on amounts in the MDCP which are greater than 120 percent of the federal long-term rate which was in effect at the time the rate was set; and (iv) payments made under retention agreements, if any. The following are amounts for 2005:

	Split Dollar Insurance Cost	Contributions to 401(k) and MDCP	Above Market Interest on MDCP	Total
Peggy Y. Fowler	\$720	\$14,980	\$ -	\$15,700
James J. Piro	-	13,296	223	13,519
Stephen M. Quennoz	-	9,151	620	9,771
Douglas R. Nichols	-	12,519	-	12,519
Stephen R. Hawke	-	10,400	147	10,547

Pension Plans

Estimated annual retirement benefits payable to the Named Executive Officers are shown in the table below. Amounts in the first line of the table reflect payments from the pension plan for PGE employees (PGE Pension Plan) at the maximum compensation base of \$220,000 (unreduced benefit at age 65). Additional amounts in the table reflect payments from the PGE Pension Plan and Supplemental Executive Retirement Plan (SERP) on a combined basis (unreduced benefit at age 62 or at combined age and years of service of 85).

Pension Plan Table
Estimated Annual Retirement Benefit
Straight-Life Annuity

	Final Average Earnings	Years of Service				
		15	20	25	30	35
Pension Plan Only	\$220,000	\$52,439	\$69,918	\$87,398	\$104,878	\$110,378
Pension Plan and SERP	700,000	-	-	-	420,000	420,000
	800,000	-	-	-	480,000	480,000

Pursuant to rules under the Internal Revenue Code of 1986, as amended, a pension plan may not base benefits on annual compensation in excess of \$220,000 or pay annual benefits in excess of \$175,000. These limits are periodically adjusted for changes in the cost of living. Compensation used to calculate benefits under the PGE Pension Plan is based on a five-year average of base salary only (the highest 60 consecutive months within the last 10 years). PGE Pension Plan benefits are reduced by 2% annually for those that retire at ages 60 to 64 and 5% annually for those that retire at ages 55 to 59.

Compensation used to calculate benefits under the combined PGE Pension Plan and SERP is based on a three-year average of base salary and annual performance bonus amounts (the highest 36 consecutive months within the last 10 years), as reported in the Summary Compensation Table. Surviving spouses receive one half the participant's retirement benefit from the SERP, plus the joint and survivor benefit, if any, from the PGE Pension Plan. In addition to the aforementioned annual retirement benefits, an additional temporary Social Security Supplement is paid until the participant is eligible for social security retirement benefits. Retirement benefits are not subject to any deduction for social security. The minimum retirement age under the SERP is 55. The SERP was closed to new participants in 1997.

Peggy Y. Fowler is a participant in both plans. The other Named Executive Officers participate only in the PGE Pension Plan. The Named Executive Officers have the following number of years of service with the Company: Peggy Y. Fowler, 32; James J. Piro, 26; Stephen M. Quennoz, 15; Douglas R. Nichols, 15; and, Stephen R. Hawke, 32. Under the Company's SERP, Peggy Y. Fowler is eligible to retire without a reduction in benefits upon attainment of the age of 55.

Compensation of Directors

In 2005, non-management directors received fees for their Board service, including \$80,000 per year for serving on the Board and \$20,000 per year for serving as Chair of the Board or as Chair of the Audit Committee. Director fees are paid quarterly and apportioned from the date of appointment.

The following table indicates total fees paid to outside directors for their Board service during 2005.

Name	Board Service Fees Paid		
	Directorship	Chair	Total
John W. Ballantine (director since February 1, 2004)	\$ 80,000	\$ -	\$ 80,000
Corbin A. McNeill, Jr. (director since February 1, 2004)	80,000	20,000	100,000
Raymond S. Troubh (director since April 1, 2004)	80,000	-	80,000

Compensation Committee Interlocks and Insider Participation

The Compensation Committee of the PGE Board of Directors is responsible for developing and administering compensation philosophy. Committee members during 2005 were John W. Ballantine, Robert S. Bingham, and Robert H. Walls, Jr. Mr. Walls resigned as Chairman of the Compensation Committee effective January 9, 2005. Mr. Ballantine was appointed as Committee Chairman on January 10, 2005. Salary increases, annual incentive awards, and long-term incentive grants (if any) are reviewed annually to ensure consistency with PGE's total compensation philosophy. No Compensation Committee interlocks or insider participation requiring disclosure under Item 402(j) of Regulation S-K existed during 2005.

Item 12. Security Ownership of Certain Beneficial Owners and Management

PGE is a wholly owned subsidiary of Enron.

Item 13. Certain Relationships and Related Transactions

There are no relationships or transactions required to be disclosed under Item 404 of Regulation S-K.

Item 14. Principal Accounting Fees and Services

The Company incurred the following fees for services rendered by Deloitte & Touche LLP (Deloitte & Touche) and, its predecessor auditor, PricewaterhouseCoopers LLP (PwC) for the years ended December 31, 2005 and 2004.

Audit Fees

Aggregate fees billed or expected to be billed for professional services rendered for the audit of PGE's consolidated financial statements for the years ended December 31, 2005 and 2004 and for the review of the interim consolidated financial statements included in quarterly reports are set forth below. Audit Fees also include services normally provided in connection with statutory and regulatory filings or engagements and assistance with and review of documents filed with the SEC.

	PwC (a)	Deloitte & Touche
2005	\$ -	\$835,000
2004	11,770 (b)	796,487 (b)

- (a) Fees for services provided to consent to the inclusion of their audit report in PGE's 2004 Form 10-K after dismissal on January 9, 2004.
(b) Include adjustments to amounts previously reported to reflect actual amounts billed.

Audit-Related Fees

Aggregate fees billed in the year indicated for assurance and related services that are reasonably related to the performance of the audit or review of PGE's consolidated financial statements and are not reported under "Audit Fees" are set forth below. These services include employee benefit plan audits, due diligence related to the planned stock distribution and Enron auction process for PGE, attest services that are not required by statute or regulation, and consultations concerning financial accounting and reporting standards.

	PwC (c)	Deloitte & Touche
2005	\$ -	\$141,637
2004	720	129,856

- (c) Fees for consultation concerning financial accounting and reporting standards prior to dismissal.

Tax Fees

Tax Fees billed in the year indicated for professional tax services as set forth below.

	PwC	Deloitte & Touche
2005	\$ -	\$ -
2004	-	-

All Other Fees

Aggregate fees billed in the year indicated for all other products and services not included in the above three categories are set forth below. These primarily include reference products related to income taxes and financial accounting matters.

	PwC	Deloitte & Touche
2005	\$ -	\$ 24,262
2004	-	16,373

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

The Audit Committee's policy requires pre-approval of all audit and permissible non-audit services provided by the independent auditors. These services may include audit services, audit-related services, tax services and other services. Pre-approval is generally provided for up to one year and any pre-approval is detailed as to the particular service or category of services and is generally subject to a specific budget. Management and the independent auditors are required to periodically report to the Audit Committee regarding the extent of services provided by the independent auditors in accordance with what was pre-approved, and the fees for the services rendered to date. The Audit Committee may also pre-approve particular services on a case-by-case basis. All audit and permissible non-audit services provided by the independent auditors during 2005 were pre-approved by the Audit Committee.

Part IV

Item 15. Exhibits, Financial Statement Schedules

(a)	<u>Index to Financial Statements and Financial Statement Schedules</u>	<u>Page</u>
	<u>Financial Statements</u>	
	Report of Independent Registered Public Accounting Firm	80
	Consolidated Statements of Income for each of the three years in the period ended December 31, 2005	81
	Consolidated Statements of Retained Earnings for each of the three years in the period ended December 31, 2005	81
	Consolidated Statements of Comprehensive Income for each of the three years in the period ended December 31, 2005	82
	Consolidated Balance Sheets at December 31, 2005 and 2004	83
	Consolidated Statements of Cash Flows for each of the three years in the period ended December 31, 2005	84
	Notes to the Consolidated Financial Statements	85
	<u>Financial Statement Schedule</u>	
	Schedule II - Consolidated Valuation and Qualifying Accounts	145
	<u>Exhibits</u>	
	See Exhibit Index on Page 147 of this report.	

Portland General Electric Company and Subsidiaries
Schedule II - Consolidated Valuation and Qualifying Accounts
For the Years Ended December 31, 2005, 2004, and 2003
(In Millions)

	<u>Allowance for Uncollectible Accounts</u>
Balance at January 1, 2003	\$ 109
Provision charged to income	24
Amounts written off, less recoveries	<u>(9)</u>
Balance at December 31, 2003	124
Balance at January 1, 2004	124
Provision charged to income	11
Amounts written off, less recoveries	<u>(85)</u>
Balance at December 31, 2004	50
Balance at January 1, 2005	50
Provision charged to income	7
Amounts written off, less recoveries	<u>(7)</u>
Balance at December 31, 2005	\$ <u>50</u>

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Portland General Electric Company

March 15, 2006

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

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

<u>/s/ Peggy Y. Fowler</u> Peggy Y. Fowler	Chief Executive Officer and President and Director	March 15, 2006
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<u>/s/ James J. Piro</u> James J. Piro	Executive Vice President, Finance Chief Financial Officer and Treasurer	March 15, 2006
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<u>/s/ Kirk M. Stevens</u> Kirk M. Stevens	Controller and Assistant Treasurer	March 15, 2006
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*John W. Ballantine	Director	March 15, 2006
*Robert S. Bingham	Director	March 15, 2006
*David A. Dietzler	Director	March 15, 2006
*Mark B. Ganz	Director	March 15, 2006
*Corbin A. McNeill, Jr.	Director	March 15, 2006
*Robert G. Miller	Director	March 15, 2006
*M. Lee Pelton	Director	March 15, 2006
*Maria M. Pope	Director	March 15, 2006
*Robert T.F. Reid	Director	March 15, 2006
*Raymond S. Trough	Director	March 15, 2006

*By /s/ Kirk M. Stevens
(Kirk M. Stevens, Attorney-in-Fact)

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES

EXHIBIT INDEX

Number	Exhibit
(2)	Plan of Acquisition, Reorganization, Arrangement, Liquidation or Succession
2.1	* Amended and Restated Agreement and Plan of Merger, dated as of July 20, 1996 and amended and restated as of September 24, 1996 among Enron Corp, Enron Oregon Corp and Portland General Corporation [Amendment 1 to S-4 Registration Nos. 333-13791 and 333-13791-1, dated October 10, 1996, Exhibit No. 2.1].
(3)	Articles of Incorporation and Bylaws
3.1	* Copy of Articles of Incorporation of Portland General Electric Company [Registration No. 2-78085, Exhibit (4)].
3.2	* Certificate of Amendment, dated July 2, 1987, to the Articles of Incorporation of Portland General Electric Company limiting the personal liability of directors [Form 10-K for the fiscal year ended December 31, 1987, Exhibit (3)].
3.3	* Articles of Amendment to Articles of Incorporation of Portland General Electric Company, dated July 8, 1992, for series of Preferred Stock (\$7.75 Series) [Registration Statement No. 33-46357, Exhibit (4)(a)].
3.4	* Articles of Amendment to Articles of Incorporation of Portland General Electric Company, dated September 30, 2002, creating Limited Voting Junior Preferred Stock [Form 10-Q for the quarter ended September 30, 2002, Exhibit (3)].
3.5	* Amended and Restated Bylaws of Portland General Electric Company as amended on February 1, 2004 [Form 10-K for the fiscal year ended December 31, 2003, Exhibit (3)].
(4)	Instruments defining the rights of security holders, including indentures
4.1	* Portland General Electric Company Indenture of Mortgage and Deed of Trust dated July 1, 1945 [Form 8, Amendment No. 1 dated June 14, 1965].
4.2	* Fortieth Supplemental Indenture dated October 1, 1990 [Form 10-K for the fiscal year ended December 31, 1990, Exhibit (4)].
4.3	* Forty-First Supplemental Indenture dated December 1, 1991 [Form 10-K for the fiscal year ended December 31, 1991, Exhibit (4)].
4.4	* Forty-Second Supplemental Indenture dated April 1, 1993 [Form 10-Q for the quarter ended March 31, 1993, Exhibit (4)].
4.5	* Forty-Third Supplemental Indenture dated July 1, 1993 [Form 10-Q for the quarter ended September 30, 1993, Exhibit (4)].
4.6	* Forty-Fifth Supplemental Indenture dated May 1, 1995 [Form 10-Q for the quarter ended June 30, 1995, Exhibit (4)].

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES

EXHIBIT INDEX

Number	Exhibit
4.7	* Forty-Seventh Supplemental Indenture dated December 14, 2001 [Form 10-K for the fiscal year ended December 31, 2001, Exhibit (4)].
4.8	* Supplemental Indenture dated April 30, 1999 [S-3 Registration No. 333-77469, dated April 30, 1999, Exhibit 4(c)].
	Certain instruments defining the rights of holders of other long-term debt of PGE are omitted pursuant to Item 601(b)(4)(iii)(A) of Regulation S-K because the total amount authorized under each such omitted instrument does not exceed 10 percent of the total assets of PGE and its subsidiaries on a consolidated basis. PGE hereby agrees to furnish a copy of any such instrument to the SEC upon request.
(10)	Material Contracts
10.1	* Residential Purchase and Sale Agreement with the Bonneville Power Administration [Form 10-K for the fiscal year ended December 31, 1981, Exhibit (10)].
10.2	* Power Sales Contract and Amendatory Agreement Nos. 1 and 2 with Bonneville Power Administration [Form 10-K for the fiscal year ended December 31, 1982, Exhibit (10)].
	The following 12 exhibits were filed in conjunction with the 1985 Boardman/Intertie Sale:
10.3	* Long-term Power Sale Agreement dated November 5, 1985 [Form 10-K for the fiscal year ended December 31, 1985, Exhibit (10)].
10.4	* Long-term Transmission Service Agreement dated November 5, 1985 [Form 10-K for the fiscal year ended December 31, 1985, Exhibit (10)].
10.5	* Participation Agreement dated December 30, 1985 [Form 10-K for the fiscal year ended December 31, 1985, Exhibit (10)].
10.6	* Lease Agreement dated December 30, 1985 [Form 10-K for the fiscal year ended December 31, 1985, Exhibit (10)].
10.7	* PGE-Lessee Agreement dated December 30, 1985 [Form 10-K for the fiscal year ended December 31, 1985, Exhibit (10)].
10.8	* Asset Sales Agreement dated December 30, 1985 [Form 10-K for the fiscal year ended December 31, 1985, Exhibit (10)].
10.9	* Bargain and Sale Deed, Bill of Sale, and Grant of Easements and Licenses, dated December 30, 1985 [Form 10-K for the fiscal year ended December 31, 1985, Exhibit (10)].

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES

EXHIBIT INDEX

Number	Exhibit
10.10	* Supplemental Bill of Sale dated December 30, 1985 [Form 10-K for the fiscal year ended December 31, 1985, Exhibit (10)].
10.11	* Trust Agreement dated December 30, 1985 [Form 10-K for the fiscal year ended December 31, 1985, Exhibit (10)].
10.12	* Tax Indemnification Agreement dated December 30, 1985 [Form 10-K for the fiscal year ended December 31, 1985, Exhibit (10)].
10.13	* Trust Indenture, Mortgage and Security Agreement dated December 30, 1985 [Form 10-K for the fiscal year ended December 31, 1985, Exhibit (10)].
10.14	* Restated and Amended Trust Indenture, Mortgage and Security Agreement dated February 27, 1986 [Form 10-K for the fiscal year ended December 31, 1997, Exhibit (10)].
Executive Compensation Plans and Arrangements	
10.15	* Portland General Electric Company Annual Cash Incentive MasterPlan for 2004 [Form 10-K for the fiscal year ended December 31, 2003, Exhibit (10)].
10.16	* Updated summary description of the Portland General Electric Company Annual Cash Incentive Master Plan for 2004 [Form 8-K dated February 12, 2005, Exhibit (10)].
10.17	* Summary description of the Portland General Electric Company 2005 Annual Cash Incentive Plan [Form 8-K dated March 29, 2005, Exhibit (10)].
10.18	* Portland General Electric Company Management Deferred Compensation Plan, dated March 12, 2003 [Form 10-Q for the quarter ended March 31, 2003, Exhibit (10)].
10.19	* Portland General Electric Company Severance Pay Plan for Executive Employees, dated June 15, 2005 [Form 10-K dated June 15, 2005, Exhibit (10)].
10.20	* Portland General Electric Company Outplacement Assistance Plan, dated June 15, 2005 [Form 10-K dated June 15, 2005, Exhibit (10)].
10.21	* Portland General Electric Company 2005 Management Deferred Compensation Plan, dated March 4, 2005 (Form 10-K for the fiscal year ended December 31, 2004).
10.22	* Portland General Electric Company Supplemental Executive Retirement Plan, dated March 12, 2003 [Form 10-Q for the quarter ended March 31, 2003, Exhibit (10)].
10.23	* Portland General Electric Company Senior Officers' Life Insurance Benefit Plan, dated March 12, 2003 [Form 10-Q for the quarter ended March 31, 2003, Exhibit (10)].
10.24	* Portland General Electric Company Umbrella Trust for Management, dated March 12, 2003 [Form 10-Q for the quarter ended March 31, 2003, Exhibit (10)].

PORTLAND GENERAL ELECTRIC COMPANY AND SUBSIDIARIES

EXHIBIT INDEX

Number	Exhibit
10.25	* Director Compensation Arrangement [Form 10-K for the fiscal year ended December 31, 2003, Exhibit (10)].
10.26	* Portland General Electric Company 2006 Stock Incentive Plan [Form 8-K dated February 21, 2006, Exhibit (10)].
(24)	Power of Attorney
24.1	Power of Attorney (filed herewith).
(31)	Rule 13a-14(a)/15d-14(a) Certifications
31.1	Certification of Chief Executive Officer of Portland General Electric Company (filed herewith).
31.2	Certification of Chief Financial Officer of Portland General Electric Company (filed herewith).
(32)	Section 1350 Certifications
32	Certifications of Chief Executive Officer and Chief Financial Officer of Portland General Electric Company Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).

* Incorporated by reference as indicated.

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

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

EXHIBIT 31.1

**CERTIFICATION OF
CHIEF EXECUTIVE OFFICER
OF PORTLAND GENERAL ELECTRIC COMPANY**

I, Peggy Y. Fowler, certify that:

1. I have reviewed this Annual Report on Form 10-K of Portland General Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 15, 2006

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

EXHIBIT 31.2

**CERTIFICATION OF
CHIEF FINANCIAL OFFICER
OF PORTLAND GENERAL ELECTRIC COMPANY**

I, James J. Piro, certify that:

1. I have reviewed this Annual Report on Form 10-K of Portland General Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:
 - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - (b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - (c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 15, 2006

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

EXHIBIT 32

**CERTIFICATIONS OF
CHIEF EXECUTIVE OFFICER AND CHIEF FINANCIAL OFFICER
OF PORTLAND GENERAL ELECTRIC COMPANY
PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

We, Peggy Y. Fowler, Chief Executive Officer and President, and James J. Piro, Executive Vice President, Finance, Chief Financial Officer and Treasurer of Portland General Electric Company (the "Company"), hereby certify that the Company's Annual Report on Form 10-K for the year ended December 31, 2005, as filed with the Securities and Exchange Commission on the date hereof pursuant to Section 13(a) of the Securities Exchange Act of 1934 (the "Report"), fully complies with the requirements of that section.

We further certify that the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

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

Date: March 15, 2006

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

Date: March 15, 2006

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended March 31, 2006

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 1-5152

PACIFICORP

(Exact name of registrant as specified in its charter)

State of Oregon
(State or other jurisdiction
of incorporation or organization)

93-0246090
(I.R.S. Employer Identification No.)

825 N.E. Multnomah Street, Portland, Oregon
(Address of principal executive offices)

97232
(Zip Code)

(503) 813-5000
(Registrant's telephone number)

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

Title of each Class

5% Preferred Stock (Cumulative; \$100 Stated Value)
Serial Preferred Stock (Cumulative; \$100 Stated Value)
No Par Serial Preferred Stock (Cumulative; \$100 Stated Value)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act.

Yes ☐ No ☒

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

Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act).

Large accelerated filer ☐

Accelerated filer ☐

Non-accelerated filer ☒

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes ☐

No ☒

<u>Class</u>	<u>Outstanding at May 19, 2006</u>
Common Stock, no par value	357,060,915 shares

All shares of outstanding common stock are indirectly owned by MidAmerican Energy Holdings Company, 666 Grand Avenue, Des Moines, Iowa.

DOCUMENTS INCORPORATED BY REFERENCE

None.

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DEFINITIONS

When the following terms are used in the text, they will have the meanings indicated:

<u>Term</u>	<u>Meaning</u>
CPUC.....	California Public Utilities Commission
FERC.....	Federal Energy Regulatory Commission
IPUC.....	Idaho Public Utilities Commission
kWh.....	Kilowatt-hour(s), one kilowatt continuously for one hour
MEHC.....	MidAmerican Energy Holdings Company, an Iowa corporation and indirect parent company of PacifiCorp
MW.....	Megawatt
MWh.....	Megawatt-hour(s), one megawatt continuously for one hour
OPUC.....	Oregon Public Utility Commission
PacifiCorp.....	PacifiCorp, an Oregon corporation and direct, wholly owned subsidiary of PPW Holdings LLC
PHI.....	PacifiCorp Holdings, Inc., a Delaware corporation and non-operating United States holding company and the former direct parent company of PacifiCorp
PPW Holdings LLC	PPW Holdings LLC, the direct parent company of PacifiCorp
ScottishPower.....	Scottish Power plc, the former ultimate, indirect parent company of PHI and PacifiCorp
SEC.....	Securities and Exchange Commission
SFAS.....	Statement of Financial Accounting Standards
UPSC.....	Utah Public Service Commission
WPSC.....	Wyoming Public Service Commission
WUTC.....	Washington Utilities and Transportation Commission

PART I

ITEM 1. BUSINESS

OVERVIEW

Ownership by MEHC; Sale of PacifiCorp

On March 21, 2006, MidAmerican Energy Holdings Company ("MEHC") completed its purchase of all of PacifiCorp's outstanding common stock from PacifiCorp Holdings, Inc. ("PHI"), a subsidiary of Scottish Power plc ("ScottishPower"), pursuant to the Stock Purchase Agreement among MEHC, ScottishPower and PHI dated May 23, 2005, as amended on March 21, 2006 (the "Stock Purchase Agreement"). The cash purchase price was \$5.1 billion. PacifiCorp's common stock was directly acquired by a subsidiary of MEHC, PPW Holdings LLC. As a result of this transaction, MEHC controls the significant majority of PacifiCorp's voting securities, which include both common and preferred stock. MEHC, a global energy company based in Des Moines, Iowa, is a majority-owned subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway"). All descriptions of the terms of the Stock Purchase Agreement contained in this Annual Report are modified in their entirety by reference to the terms of such agreement, which is included as an exhibit hereto.

Operations

PacifiCorp is a regulated electricity company serving retail customers in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho and California. As a vertically integrated electric utility, PacifiCorp owns or has contracts for fuel sources such as coal and natural gas and uses these fuel sources, as well as wind, geothermal and water resources, to generate electricity at its power plants. This electricity, together with electricity purchased on the wholesale market, is then transmitted via a grid of transmission lines throughout PacifiCorp's six-state region. The electricity is then transformed to lower voltages and delivered to customers through PacifiCorp's distribution system. PacifiCorp sells electricity primarily in the retail market, with sales to residential, commercial and industrial customers. PacifiCorp also sells electricity in the wholesale market in connection with excess electricity generation or balancing activities. Subsidiaries of PacifiCorp support its electric utility operations by providing coal mining and other fuel-related services, as well as environmental remediation. PacifiCorp's goal is to provide safe, reliable, low-cost electricity to its customers, with fair and increasing earnings to its common shareholder. PacifiCorp expects that costs prudently incurred to provide service to its customers will be included as allowable costs for state rate-making purposes.

Following the closing of PacifiCorp's sale, MEHC announced a new organizational structure under the direction of a newly appointed chairman and chief executive officer, who oversees the company's entire operations. The PacifiCorp Energy operational unit is responsible for PacifiCorp's electric generation, commercial and energy trading, and coal-mining functions. The Pacific Power operational unit is responsible for delivering electricity to customers in Oregon, Washington and California. The Rocky Mountain Power operational unit is responsible for delivering electricity to customers in Utah, Wyoming and Idaho.

Regulation

PacifiCorp is subject to comprehensive regulation by the Federal Energy Regulatory Commission (the "FERC"), the Utah Public Service Commission (the "UPSC"), the Oregon Public Utility Commission (the "OPUC"), the Wyoming Public Service Commission (the "WPSC"), the Washington Utilities and Transportation Commission (the "WUTC"), Idaho Public Utility Commission (the "IPUC"), the California Public Utilities Commission (the "CPUC"), and other federal, state and local regulatory agencies. These agencies regulate many aspects of PacifiCorp's business, including customer rates, service territories, sales of securities, asset acquisitions and sales, accounting policies and practices, wholesale sales and purchases of electricity, and the operation of its electric generation and transmission facilities.

Employees

On March 31, 2006, PacifiCorp had 6,750 employees, 58.4% of which were covered by union contracts, principally with the International Brotherhood of Electrical Workers, the Utility Workers Union of America, International Brotherhood of Boilermakers and the United Mine Workers of America.

Location and Information Requests

The location of PacifiCorp's principal offices is 825 N.E. Multnomah Street, Portland, Oregon 97232. PacifiCorp's website address is www.pacificorp.com. PacifiCorp makes available free of charge, on or through its website, its annual, quarterly and current reports, and any amendments to those reports, as soon as reasonably practicable after electronically filing such reports with the United States Securities and Exchange Commission (the "SEC"). Information contained on PacifiCorp's website is not part of this report. Reports and other information regarding PacifiCorp that are required to be filed with the SEC may also be obtained from the SEC's website at www.sec.gov.

POWER AND FUEL SUPPLY

Generating Plants

PacifiCorp owns, or has interests in, the following types of electricity generating plants:

	Plants	Nameplate Rating (MW)	Net Plant Capability (MW)
Coal	11	6,585.9	6,104.4
Natural gas and other	6	1,348.7	1,174.0
Hydroelectric	51	1,083.6	1,159.4
Wind	1	32.6	32.6
Total	69	9,050.8	8,470.4

The natural gas and other plants include the Currant Creek Power Plant, which commenced full combined-cycle operation in March 2006, adding 523.0 megawatts ("MW") of capability to PacifiCorp's generation portfolio.

The following table shows the estimated percentage of PacifiCorp's total energy requirements supplied by its generation plants and through short- and long-term contracts or spot market purchases during the years ended March 31, 2006, 2005 and 2004. See "Wholesale Sales and Purchased Electricity" below for more information.

	Years Ended March 31,		
	2006	2005	2004
Coal	67.5 %	67.3 %	67.8 %
Natural gas and other	4.3	4.8	4.7
Hydroelectric	6.2	4.6	5.4
Wind	0.2	0.2	0.2
Total energy generated	78.2	76.9	78.1
Purchase and exchange contracts	21.8	23.1	21.9
Total	100.0 %	100.0 %	100.0 %

The share of PacifiCorp's energy requirements generated by its plants will vary from year to year and is determined by factors such as planned and unplanned outages, availability and price of coal and natural gas, precipitation and snowpack levels, environmental considerations and the market price of electricity.

Coal

As of March 31, 2006, PacifiCorp had an estimated 248.3 million tons of recoverable coal reserves in mines owned or leased by it. During the year ended March 31, 2006, these mines supplied 32.3% of PacifiCorp's total coal requirements, compared to 28.6% during the year ended March 31, 2005 and 30.4% during the year ended March 31, 2004. The remaining coal requirements are acquired through other long-term and short-term contracts. PacifiCorp-owned mines are located adjacent to many of its coal-fired generating plants, which significantly reduces overall transportation costs included in fuel expense. For further information, see "Item 2. Properties."

In an effort to lower costs and obtain better quality coal, the Jim Bridger Mine is in the process of developing an underground mine to access 57.0 million tons of PacifiCorp's coal reserves. Underground mine development and limited coal production began during the year ended March 31, 2005 and sustained operations are expected to begin by March 31, 2007. The life of the underground mine is expected to be approximately 15 years.

Natural Gas

PacifiCorp currently utilizes natural gas to fuel four owned and one leased generating plants (composed of 16 generating units) that, at full capacity, require a maximum of 324,000 MMBtu (million British thermal units) of natural gas per day.

Additional electric generation resources required by PacifiCorp's Integrated Resource Plans discussed below, including the Lake Side Power Plant, could increase the natural gas requirement to 415,000 MMBtu per day or more. PacifiCorp has entered into transportation contracts to facilitate movement of natural gas to the Lake Side Power Plant. These contracts reflect PacifiCorp's fuel strategy that focuses on the management and mitigation of risks associated with supplying natural gas.

The growth of PacifiCorp's natural gas requirements requires a prudent, disciplined and well-documented approach to natural gas procurement and hedging. PacifiCorp has developed a natural gas strategy that addresses the need to economically hedge the commodity risk (physical availability and price), the transportation risk and the storage risk associated with its forecasted and potentially growing natural gas requirements. This natural gas strategy, combined with the prospect for increasing natural gas requirements, is expected to increase the volume and types of PacifiCorp's procurement and economic hedging activity.

PacifiCorp manages its natural gas supply requirements by entering into forward commitments for physical delivery of natural gas. PacifiCorp also manages its exposure to increases in natural gas supply costs through forward commitments for the purchase of physical natural gas at fixed prices and financial swap contracts that settle in cash based on the difference between a fixed price that PacifiCorp pays and a floating market-based price that PacifiCorp receives. As of March 31, 2006, PacifiCorp had economically hedged 100.0% of its forecasted physical and financial exposure for the remainder of calendar 2006 and had economically hedged 100.0% of its forecasted physical and financial exposure for calendar 2007. For calendar 2008, PacifiCorp currently has hedged 88.0% of its physical exposure and 96.0% of its financial exposure. This economic hedging includes the additional supply requirements arising from the Lake Side Power Plant and the recently constructed Currant Creek Power Plant.

Hydroelectric

PacifiCorp's hydroelectric portfolio consists of 51 plants with a net plant capability of 1,159.4 MW. These plants account for approximately 14.0% of PacifiCorp's total generating capacity, helping satisfy a significant portion of PacifiCorp's reserve requirements and providing operational benefits such as flexible generation and voltage control. Hydroelectric plants are located in the following states: Utah, Oregon, Wyoming, Washington, Idaho, California and Montana.

The amount of electricity PacifiCorp is able to generate from its hydroelectric plants depends on a number of factors, including snowpack in the mountains upstream of its hydroelectric facilities, reservoir storage, precipitation in its watersheds, plant availability and restrictions imposed by oversight bodies due to competing water management objectives. When these factors are favorable, PacifiCorp can generate more electricity using its hydroelectric plants. When these factors are unfavorable, PacifiCorp must increase its reliance on more expensive thermal plants and purchased electricity.

PacifiCorp operates the majority of its hydroelectric generating portfolio under long-term licenses from the FERC. These licenses are granted by the FERC for periods of 30 to 50 years. Several of PacifiCorp's long-term operating licenses have expired or will expire in the next few years. Hydroelectric facilities operating under expired licenses may operate under annual licenses granted by the FERC until new operating licenses are issued. Hydroelectric relicensing and the related environmental compliance requirements are subject to a degree of uncertainty. PacifiCorp expects that future costs relating to these matters may be significant and consist primarily of additional relicensing costs and capital expenditures. Electricity generation reductions may also result from additional environmental requirements. At March 31, 2006, PacifiCorp had incurred \$70.3 million in costs for ongoing hydroelectric relicensing, which are included in Construction work-in-progress on PacifiCorp's Consolidated Balance Sheet. See "Hydroelectric Relicensing" and "Hydroelectric Decommissioning" both discussed below.

Wind and Other Renewable Resources

PacifiCorp is pursuing renewable power as a viable, economic and environmentally prudent means of generating electricity. The benefits of renewable energy include low to no emissions and no fossil fuel requirements. Resources such as wind and solar are intermittent, so complementary thermal or hydroelectric resources are important to integrating intermittent renewable resources into the electric system.

PacifiCorp acquires wind and other renewable power through one PacifiCorp-owned wind farm in Wyoming and various purchased electricity agreements with wind farms in Oregon and Wyoming, as well as with renewable facilities classified as "qualifying facilities" under the Public Utility Regulatory Policies Act. PacifiCorp also owns a geothermal plant in Utah. For the year ended March 31, 2006, PacifiCorp received 256,371 MWh from its owned wind farm and geothermal plant. In this same period, 303,158 MWh were purchased from other wind sources, not including qualifying facilities.

To encourage the use of wind energy, PacifiCorp has generation, storage and delivery agreements with various other utilities. For the year ended March 31, 2006, electricity generated for delivery to customers under these agreements totaled 532,103 MWh in addition to the wind energy generated or purchased for PacifiCorp's own use.

In connection with its sale to MEHC, PacifiCorp has committed to state regulatory commissions that it will bring at least 100.0 MW of cost-effective wind resources in service by March 21, 2007 and, to the extent available, add 400.0 MW, inclusive of the 100.0 MW commitment, of cost-effective renewable resources in PacifiCorp's generation portfolio by December 31, 2007.

Future Generation and Conservation

Integrated Resource Plans

As required by state regulators, PacifiCorp uses Integrated Resource Plans to develop a long-term view of prudent future actions required to help ensure that PacifiCorp continues to provide reliable and cost-effective electric service to its customers. The Integrated Resource Plan process identifies the amount and timing of PacifiCorp's expected future resource needs and an associated optimal future resource mix that accounts for planning uncertainty, risks, reliability impacts and other factors. The Integrated Resource Plan is a coordinated effort with stakeholders in each of the six states where PacifiCorp operates. Each state commission that has Integrated Resource Plan adequacy rules judges whether the Integrated Resource Plan reasonably meets its standards and guidelines at the time the Integrated Resource Plan is filed. If the Integrated Resource Plan is found to be adequate, then it is formally "acknowledged." The Integrated Resource Plan can then be used as evidence by parties in rate-making or other regulatory proceedings.

In November 2005, PacifiCorp released an update to its 2004 Integrated Resource Plan. The updated 2004 Integrated Resource Plan identified a need for approximately 2,113.0 MW of additional resources by summer 2014, to be met with a combination of thermal generation (1,936.0 MW) and load control programs (177.0 MW). PacifiCorp also planned to implement energy conservation programs of 450.0 average MW, to continue to seek procurement of 1,400.0 MW of economic renewable resources and to use wholesale electricity transactions to make up for the remaining difference between retail load obligations and available resources.

In addition to new generation resources, substantial transmission investments could be required to deliver power to customers and provide system reliability. The actual investment requirement will depend on the location and other characteristics of the new generation resources. See "Transmission and Distribution" discussion below.

WHOLESALE SALES AND PURCHASED ELECTRICITY

In addition to its portfolio of generating plants, PacifiCorp purchases electricity in the wholesale markets to meet its retail load obligations, long-term wholesale obligations, and energy and capacity balancing requirements. For the year ended March 31, 2006, 21.8% of PacifiCorp's energy requirements were supplied by purchased electricity under short- and long-term purchase arrangements, both as defined by the FERC. PacifiCorp's energy requirements supplied by purchased electricity under short- and long-term purchase arrangements were 23.1% for the year ended March 31, 2005 and 21.9% for the year ended March 31, 2004.

Many of PacifiCorp's purchased electricity contracts have fixed-price components, which provide some protection against price volatility. PacifiCorp enters into wholesale purchase and sale transactions to balance its supply when generation and retail loads are higher or lower than expected. Generation varies with the levels of outages, hydroelectric generation conditions and transmission constraints. Retail load varies with the weather, distribution system outages, consumer trends and the level of economic activity. In addition, PacifiCorp purchases electricity in the wholesale markets when it is more economical than generating it at its own plants. PacifiCorp may also sell into the wholesale market excess electricity arising from imbalances between generation and retail load obligations, subject to pricing and transmission constraints.

PacifiCorp's wholesale transactions are integral to its retail business, providing for a balanced and economically hedged position and enhancing the efficient use of its generating capacity over the long term. Historically, PacifiCorp has been able to purchase electricity from utilities in the western United States for its own requirements. These purchases are conducted through PacifiCorp and third party transmission systems, which connect with market hubs in the Pacific Northwest to provide access to normally low-cost hydroelectric generation and in the southwestern United States to provide access to normally higher-cost fossil-fuel generation. The transmission system is available for common use consistent with open-access regulatory requirements.

TRANSMISSION AND DISTRIBUTION

Electric transmission systems deliver energy from electric generators to distribution systems for final delivery to customers. PacifiCorp plans, builds and operates a transmission system. During the year ended March 31, 2006, PacifiCorp delivered 67,810,861 MWh of electricity to customers in its two control areas through 15,580 miles of transmission lines and its 59,510 mile system of distribution lines. For further detail, see "Item 2. Properties – Transmission and Distribution."

PacifiCorp's transmission system is part of the Western Interconnection, the regional grid in the west. The Western Interconnection includes the interconnected transmission systems of 14 western states, two Canadian provinces and parts of Mexico that make up the Western Electric Coordinating Council. The map under "Service Territories" below shows PacifiCorp's transmission grid. PacifiCorp's transmission system, together with contractual rights on other transmission systems, enables PacifiCorp to integrate and access generation resources to meet its customer load requirements. Due to PacifiCorp's continuing commitment to improve customer service and network safety and to enhance system reliability and performance, PacifiCorp has focused on infrastructure improvement projects in targeted areas. PacifiCorp and MEHC have committed to a number of transmission and distribution system investments in connection with regulatory approval of PacifiCorp's sale to MEHC. For discussion of specific planned spending see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operation – Liquidity and Capital Resources – Future Uses of Cash – Capital Expenditure Program."

PacifiCorp operates one control area on the western portion of its service territory and one control area on the eastern portion of its service territory. A control area is a geographic area with electric systems that control generation to maintain schedules with other control areas and ensure reliable operations. In operating the control areas, PacifiCorp is responsible for continuously balancing electric supply and demand by dispatching generating resources and interchange transactions so that generation internal to the control area, plus net import power, matches customer loads. PacifiCorp also schedules power deliveries over its transmission system and maintains reliability in part by verifying that customers are properly using the system within established bounds.

PacifiCorp's wholesale transmission services are regulated by the FERC under cost-based regulation subject to PacifiCorp's Open Access Transmission Tariff. In accordance with the Open Access Transmission Tariff, PacifiCorp offers several transmission services to wholesale customers:

- Network transmission service (guaranteed service that integrates generating resources to serve retail loads);
- Long-term and short-term firm point-to-point transmission service (guaranteed service with fixed delivery and receipt points); and
- Non-firm point-to-point service ("as available" service with fixed delivery and receipt points).

These services are offered on a non-discriminatory basis, meaning that all potential customers are provided an equal opportunity to access the transmission system. PacifiCorp's transmission business is managed and operated independently from the generating and marketing business in accordance with the FERC Standards of Conduct. Transmission costs are not

separated from, but rather are “bundled” with, generation and distribution costs in retail rates approved by state regulatory commissions. See “Regulation – Federal Regulatory Matters” below for further information related to the Energy Policy Act of 2005, which requires that the FERC establish and enforce standards for electric reliability.

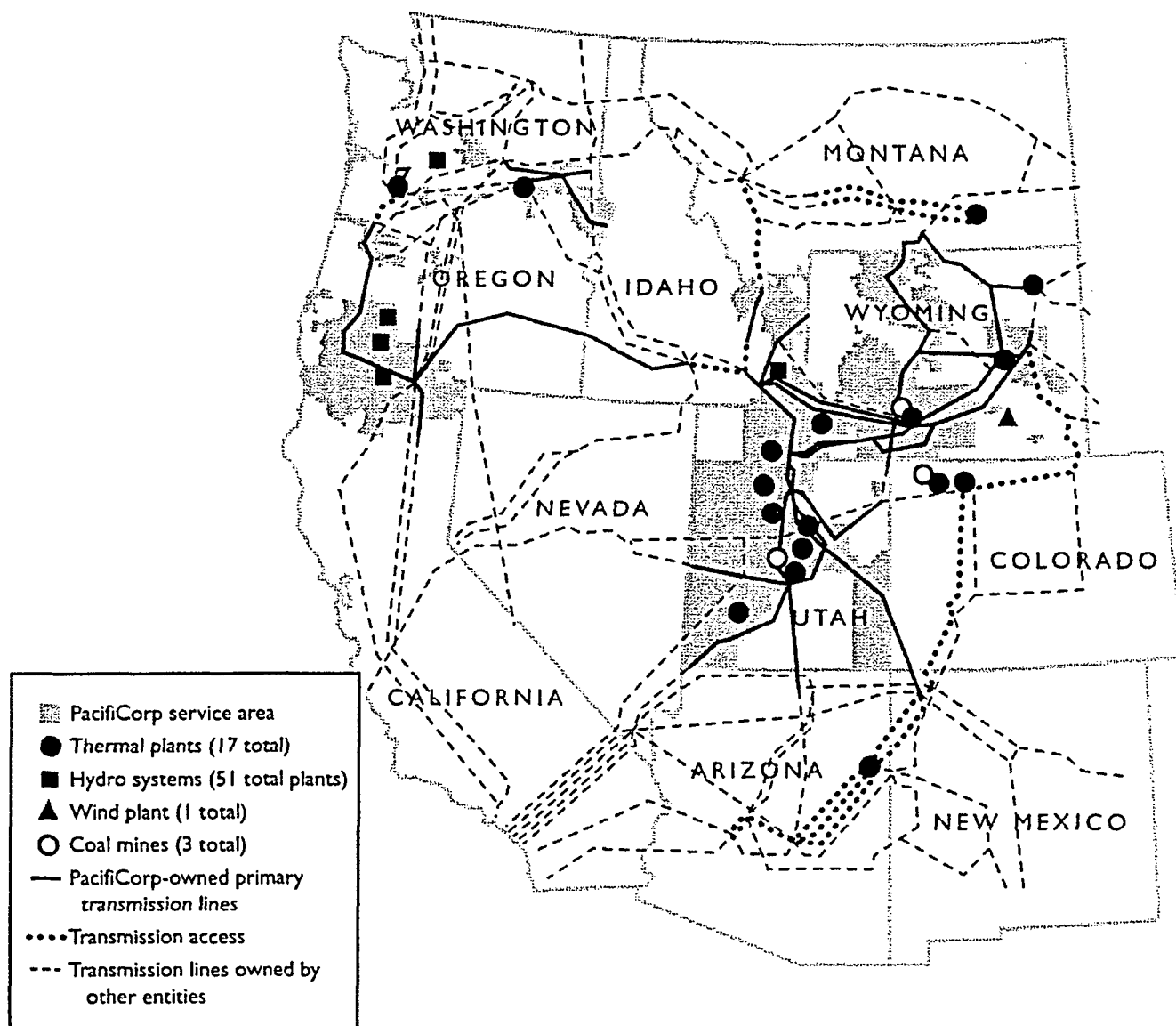
Regional Transmission Coordination

In December 1999, the FERC encouraged all companies with transmission assets to form regional transmission organizations that would manage certain operational functions of the transmission grid and plan for necessary expansion. In response, several northwest utilities, including PacifiCorp, formed a regional transmission entity, known as Grid West, that was intended to coordinate transmission functions in all or portions of eight western states and western Canada.

In April 2006, the Grid West board voted to dissolve the Grid West entity. This decision resulted primarily from the decision of key participants, including the Bonneville Power Administration to discontinue support and funding of Grid West efforts. To address the continuing need for some degree of regional transmission coordination, PacifiCorp and the other parties are considering smaller-scale initiatives that could provide value for customers.

SERVICE TERRITORIES

PacifiCorp serves approximately 1.6 million retail customers in service territories aggregating approximately 136,000 square miles in portions of six western states: Utah, Oregon, Wyoming, Washington, Idaho and California. The combined service territory’s diverse regional economy ranges from rural, agricultural and mining areas to urbanized manufacturing and government service centers. No single segment of the economy dominates the service territory, which mitigates PacifiCorp’s exposure to economic fluctuations. In the eastern portion of the service territory, mainly consisting of Utah, Wyoming and southeast Idaho, the principal industries are manufacturing, health services, recreation and mining or extraction of natural resources. In the western portion of the service territory, mainly consisting of Oregon, southeastern Washington and northern California, the principal industries are agriculture and manufacturing, with forest products, food processing, high technology and primary metals being the largest industrial sectors. The following map highlights PacifiCorp’s retail service territory, plant locations and PacifiCorp’s primary transmission lines. PacifiCorp’s generating facilities are interconnected through PacifiCorp’s own transmission lines or by contract through the transmission lines owned by others. See “Item 2. Properties” for additional information on PacifiCorp’s plants.



The geographic distribution of PacifiCorp's retail electric operating revenues for the years ended March 31, 2006, 2005 and 2004 was as follows:

	Years Ended March 31,					
	2006		2005		2004	
Utah	40.9	%	40.6	%	38.5	%
Oregon	29.3		29.3		31.5	
Wyoming	13.3		13.6		12.8	
Washington	8.4		8.0		8.4	
Idaho	5.7		6.1		6.3	
California	2.4		2.4		2.5	
	<u>100.0</u>	<u>%</u>	<u>100.0</u>	<u>%</u>	<u>100.0</u>	<u>%</u>

PacifiCorp receives authorization from state public utility commissions to serve areas within each state. This authorization is perpetual until withdrawn by the state public utility commissions. In addition, PacifiCorp has received franchises to provide electric service to customers inside incorporated areas within the states. Most franchises have terms of five years or more, but some have indefinite terms. PacifiCorp must renew franchises that expire. Governmental agencies have the right to

challenge PacifiCorp's right to serve in a specific area and can condemn PacifiCorp's property under certain circumstances in accordance with the laws in each state. However, PacifiCorp vigorously challenges any attempts from individuals and governmental entities to undertake forced takeover of any portions of its service territory. PacifiCorp is subject to energy regulation, legislation and political risks. Any changes in regulations and rates or legislative developments may adversely affect its business, financial condition, results of operations and cash flows. See "Item 1A. Risk Factors" for further information.

CUSTOMERS

Electricity sold to retail customers and the number of retail customers, by class of customer, for the years ended March 31, 2006, 2005 and 2004, were as follows:

	Years Ended March 31,					
	2006		2005		2004	
(Thousands of MWh)						
MWh sold						
Residential	14,880	29.7 %	14,117	28.9 %	14,460	29.7 %
Commercial	14,887	29.7	14,642	29.9	14,413	29.6
Industrial	19,746	39.4	19,454	39.8	19,133	39.3
Other	599	1.2	706	1.4	673	1.4
Total MWh sold	50,112	100.0 %	48,919	100.0 %	48,679	100.0 %
Number of retail customers (in thousands)						
Residential	1,404	85.6 %	1,373	85.5 %	1,341	85.4 %
Commercial	198	12.1	194	12.1	190	12.1
Industrial	34	2.1	34	2.1	34	2.2
Other	4	0.2	4	0.3	5	0.3
Total	1,640	100.0 %	1,605	100.0 %	1,570	100.0 %
Retail customers						
Average annual usage per customer (kWh)	30,895		30,825		31,305	
Average annual revenue per customer	\$ 1,732		\$ 1,669		\$ 1,638	
Revenue per kWh	5.6¢		5.4¢		5.2¢	

During the year ended March 31, 2006, no single retail customer accounted for more than 2.0% of PacifiCorp's retail electric revenues, and the 20 largest retail customers accounted for 13.0% of PacifiCorp's retail electric revenues.

PacifiCorp is estimating average growth in retail megawatt-hour ("MWh") sales in PacifiCorp's franchise service territories to average between 2.0% and 3.0% annually over the five years to December 2010, depending on factors such as economic conditions, number of customers, weather, consumer trends, conservation efforts and changes in prices.

Seasonality

As a result of the geographically diverse area of operations, PacifiCorp's service territory has historically experienced complementary seasonal load patterns. In the western portion, customer demand peaks in the winter months due to heating requirements. In the eastern portion, customer demand peaks in the summer when irrigation and air-conditioning systems are heavily used.

For residential customers, within a given year, weather conditions are the dominant cause of usage variations from normal seasonal patterns. Strong Utah residential growth over the last several years and increasing installations of central air conditioning systems are contributing to faster summer peak growth.

RETAIL COMPETITION

During the year ended March 31, 2006, PacifiCorp continued to operate its retail business under state regulation, which generally prohibits retail competition. However, certain of PacifiCorp's commercial and industrial customers in Oregon have the right to choose alternative electricity suppliers. As a result of Direct Access mandated by Oregon's Senate Bill 1149, a group of customers having a total average load of approximately 11.4 average MW have chosen service from suppliers other than PacifiCorp. A group of customers having a total average load of approximately 1.6 average MW have taken service from PacifiCorp at the Daily Market Pricing Option. This service provides a market-based pricing option by linking the energy charge on a customer's bill to a representative market price index. PacifiCorp does not expect the Direct Access program and the Daily Market Pricing Option to have a material effect on earnings for the 12 months ending March 31, 2007.

In addition to Oregon's Direct Access program, others in PacifiCorp's service territories are seeking to have a choice of suppliers, exploring options to build their own generation or co-generation plants, or considering the use of alternative energy sources such as natural gas. If these customers gain the right to receive electricity from alternative suppliers, they will make their energy purchasing decisions based upon many factors, including price, service and system reliability. The use of alternative energy sources is typically based on availability, price and the general demand for electricity.

Any adoption of retail competition by the legislatures in the states served by PacifiCorp, in addition to the Direct Access program, and/or the unbundling of transmission, distribution and generation costs in regulated electricity services could have a significant adverse financial impact on PacifiCorp due to an impairment of assets, a loss of retail customers, lower profit margins or increased costs of capital and could result in increased pressure to lower the price of electricity. Although PacifiCorp believes it will continue as a regulated entity and does not expect significant retail competition in the near future, it cannot predict if or to what extent it will be subject to changes in legislation or regulation allowing retail competitors, nor can PacifiCorp predict the impact of these changes. See "Item 1A. Risk Factors – PacifiCorp is subject to energy regulation, legislation and political risks, and changes in regulations and rates or legislative developments may adversely affect its business, financial condition, results of operations and cash flows."

ENVIRONMENTAL MATTERS

PacifiCorp is subject to a number of federal, state and local environmental laws and regulations affecting many aspects of its present and future operations. These requirements relate to air emissions, water quality, waste management, hazardous chemical use, noise abatement, land use aesthetics and endangered species.

Environmental laws and regulations currently have, and future modifications may have, the effect of (i) increasing the lead time for the construction of new facilities, (ii) significantly increasing the total cost of new facilities, (iii) requiring modification of PacifiCorp's existing facilities, (iv) increasing the risk of delay on construction projects, (v) increasing PacifiCorp's cost of waste disposal, and (vi) reducing the amount of energy available from PacifiCorp's facilities. Any of these items could have a substantial impact on amounts required to be expended by PacifiCorp in the future.

In the year ended March 31, 2006, PacifiCorp spent approximately \$62.3 million on environmental capital projects. PacifiCorp currently estimates expenditures for environmental-related capital projects will total approximately \$129.2 million in the 12 months ending March 31, 2007.

Air Quality

PacifiCorp's fossil fuel-fired electricity generation plants are subject to applicable provisions of the Clean Air Act and related air quality standards promulgated by the United States Environmental Protection Agency ("EPA") and state air quality laws. The Clean Air Act provides the framework for regulation of certain air emissions and permitting and monitoring associated with those emissions. PacifiCorp owns or has interests in 11 coal-fired generating plants, which represent 72.1% of PacifiCorp's generating capability. PacifiCorp believes it has all required permits and other approvals to operate its plants and that the plants are in material compliance with applicable requirements.

The acquisition of PacifiCorp by MEHC includes a regulatory commitment to spend approximately \$812.0 million over several years to reduce emissions at PacifiCorp's generating facilities to address existing and future air quality requirements. These costs and any additional expenditures necessitated by air quality regulations are expected to be included in rates and, as such, would not have a material adverse impact on PacifiCorp's consolidated results of operations.

The EPA has in recent years implemented more stringent national ambient air quality standards for ozone and new standards for fine particulate matter. These standards set the minimum level of air quality that must be met throughout the United States. Areas that achieve the standards, as determined by ambient air quality monitoring, are characterized as being in attainment of the standard. Areas that fail to meet the standard are designated as being non-attainment areas. Generally, once an area has been designated as a non-attainment area, sources of emissions that contribute to the failure to achieve the ambient air quality standards are required to make emissions reductions. The EPA has concluded that Utah and Wyoming, where PacifiCorp's major emission sources are located, are in attainment of the ozone standards and the fine particulate matter standards.

In December 2005, the EPA proposed a revision of the ambient air quality standards for fine particles that would maintain the current annual standard and set a new, more stringent 24-hour standard for concentration of fine particulate. The EPA is scheduled to issue final rules in September 2006. Until the EPA takes final action on the proposal, the impact of the proposed rules on PacifiCorp cannot be determined.

In March 2005, the EPA released the final Clean Air Mercury Rule. The Clean Air Mercury Rule utilizes a market-based cap and trade mechanism to reduce mercury emissions from coal-burning power plants from the current nationwide level of 48 tons to 15 tons at full implementation. The Clean Air Mercury Rule's two-phase reduction program requires initial reductions of mercury emissions in 2010 and an overall reduction in mercury emissions from coal-burning power plants of 70.0% by 2018. Individual states are required to implement the Clean Air Mercury Rule through their state implementation plans. Depending on the outcome of the respective states' implementation rules, the Clean Air Mercury Rule may require PacifiCorp to reduce emissions of mercury from some or all of its coal-fired facilities through the installation of emission controls, the purchase of emission allowances, or some combination thereof.

The Clean Air Mercury Rule could, in whole or in part, be superseded or made more stringent by one of a number of multi-pollutant emission reduction proposals currently under consideration at the federal level, including pending legislative proposals that contemplate 70.0% to 90.0% reductions of sulfur dioxide, nitrogen oxides and mercury, as well as possible new federal regulation of carbon dioxide and other gases that may affect global climate change. In addition to any federal legislation that could be enacted by the United States Congress to supersede the Clean Air Mercury Rule, the rules could be changed or overturned as a result of litigation. The sufficiency of the standards established by the Clean Air Mercury Rule has been legally challenged in the United States District Court for the District of Columbia. Until final resolution of litigation challenging the Clean Air Mercury Rule, the full impact of the rules on PacifiCorp cannot be determined.

The EPA has initiated a regional haze program intended to improve visibility at specific federally protected areas. PacifiCorp and other stakeholders are participating in the Western Regional Air Partnership to help develop the technical and policy tools needed to comply with this program.

Under existing New Source Review provisions of the Clean Air Act, any facility that emits regulated pollutants is required to obtain a permit from the EPA or a state regulatory agency prior to (i) beginning construction of a new stationary source of a New Source Review-regulated pollutant, or (ii) making a physical or operational change to an existing stationary source of such pollutants. Pending or proposed air regulations will require PacifiCorp to reduce its electricity plant emissions of sulfur dioxide, nitrogen oxides and other pollutants below current levels. These reductions will be required to address regional haze programs, mercury emissions regulations and possible re-interpretations and changes to the federal Clean Air Act. In the future, PacifiCorp expects to incur significant costs to comply with various stricter air emissions requirements. These potential costs are expected to consist primarily of capital expenditures. PacifiCorp expects these costs would be included in rates and, as such, would not have a material adverse impact on PacifiCorp's consolidated results of operations. See also "Item 8. Financial Statements and Supplementary Data – Note 6 – Asset Retirement Obligations and Accrued Environmental Costs."

The EPA has requested from several utilities information and supporting documentation regarding their capital projects for various generating plants. The requests were issued as part of an industry-wide investigation to assess compliance with the New Source Review and the New Source Performance Standards of the Clean Air Act. In 2001 and 2003, PacifiCorp received requests for information from the EPA relating to PacifiCorp's capital projects at seven of its generating plants. PacifiCorp submitted information responsive to the requests and there are currently no outstanding data requests pending from the EPA. PacifiCorp cannot predict the outcome of these requests at this time.

In 2002 and 2003, the EPA proposed various changes to its New Source Review rules that clarify what constitutes routine repair, maintenance and replacement for purposes of triggering New Source Review requirements. These changes have been subject to legal challenge and, until such time as the legal challenges are resolved and the rules are effective, PacifiCorp will continue to manage projects at its generating plants in accordance with the rules in effect prior to 2002. In October 2005, the EPA proposed a rule that would change or clarify how emission increases are to be calculated for purposes of determining the applicability of the New Source Review permitting program for existing power plants. The impact of these proposed changes on PacifiCorp cannot be determined until after the rule is finalized and implemented.

In February 2005, the Kyoto Protocol became effective, requiring 35 developed countries to reduce greenhouse gas emissions by approximately 5.0% between 2008 and 2012. While the United States did not ratify the protocol, the ratification and implementation of its requirements in other countries has resulted in increased attention to climate change in the United States. In 2005, the United States Senate adopted a "sense of the Senate" resolution that puts the United States Senate on record that the United States Congress should enact a comprehensive and effective national program of mandatory, market-based limits and incentives on emissions of greenhouse gases that slow, stop, and reverse the growth of such emissions at a rate and in a manner that will not significantly harm the United States economy; and will encourage comparable action by other nations that are major trading partners and key contributors to global emissions. While debate continues at the national level over the direction of domestic climate policy, several states are developing state-specific or regional legislative initiatives to reduce greenhouse gas emissions. In December 2005, the states of Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York and Vermont signed a mandatory regional pact to reduce greenhouse gas emissions that would become effective in 2009 and ultimately would require a reduction in greenhouse gas emissions of 10.0% from 1990 levels. An executive order signed by California's governor in June 2005 would reduce greenhouse gas emissions in that state to 2000 levels by 2010, to 1990 levels by 2020 and 80.0% below 1990 levels by 2050. In addition, California is seeking to apply a greenhouse gas emission performance standard to all electricity generated within the state or delivered from outside the state that is no higher than the greenhouse gas emission levels of a state-of-the-art combined-cycle natural gas generation facility.

Litigation was filed in the federal district court for the southern district of New York seeking to require reductions of carbon dioxide emissions from generating facilities of five large electric utilities. The court dismissed the public nuisance suit, holding that such critical issues affecting the United States such as greenhouse gas emissions reductions are not the domain of the court and should be resolved by the Executive Branch and the United States Congress. This ruling has been appealed to the Second Circuit Court of Appeals. The outcome of climate change litigation and federal and state initiatives cannot be determined at this time; however, adoption of stringent limits on greenhouse gas emissions could significantly impact PacifiCorp's fossil-fueled facilities and, therefore, its results of operations and cash flows. PacifiCorp includes a projected additional cost for carbon dioxide emissions in its Integrated Resource Plans when evaluating proposed new resources.

The EPA's regulation of certain pollutants under the Clean Air Act, and its failure to regulate other pollutants, is being challenged by various lawsuits brought by both individual state attorney generals and environmental groups. To the extent that these actions may be successful in imposing additional and/or more stringent regulation of emissions on fossil-fueled facilities in general and PacifiCorp's facilities in particular, such actions could significantly impact PacifiCorp's fossil-fueled facilities and, therefore, its results of operations and cash flows.

Water Quality

The federal Clean Water Act and individual state clean-water regulations require a permit for the discharge of wastewater, including storm water runoff from electricity plants and coal storage areas, into surface water and groundwater. Additionally, PacifiCorp believes that it currently has, or has initiated the process to receive, all required water quality permits.

Endangered Species

The federal Endangered Species Act of 1973 and similar state statutes protect species threatened with possible extinction. Protection of the habitat of endangered and threatened species makes it difficult and more costly to perform some of PacifiCorp's core activities, including the siting, construction and operation of new and existing transmission and distribution facilities, as well as thermal, hydroelectric and wind generation plants. In addition, issues affecting endangered species can impact the relicensing of existing hydroelectric generating projects. This can generally reduce the generating output and operational flexibility, and potentially increase the costs of operation, of PacifiCorp's own hydroelectric resources, as well as raise the price PacifiCorp pays to purchase wholesale electricity from hydroelectric facilities owned by others.

Environmental Cleanups

Under the Comprehensive Environmental Response, Compensation and Liability Act, the Resource Conservation and Recovery Act and similar state statutes, entities that dispose of, or arrange for the disposal of, hazardous materials may be liable for cleanup of the contaminated property. In addition, the current or former owners or operators of affected sites may be liable. PacifiCorp has been identified as a potentially responsible party in connection with a number of cleanup sites because of its current or past ownership or operation of certain properties or because PacifiCorp sent materials deemed to be hazardous to the property in the past. PacifiCorp has completed several cleanup actions and is actively participating in investigations and remediation actions at other sites. See "Item 8. Financial Statements and Supplementary Data – Note 6 – Asset Retirement Obligations and Accrued Environmental Costs" for further discussion.

Mine Reclamation

The federal Surface Mining Control and Reclamation Act of 1977 and similar state statutes establish operational, reclamation and closure standards that must be met during and upon completion of mining activities. These obligations mandate that mine property be restored consistent with specific standards and the approved reclamation plan. PacifiCorp's mining operations are subject to these reclamation and closure requirements. Significant expenditures are being incurred for both ongoing and final reclamation. For further discussion, see "Item 2. Properties" and "Item 8. Financial Statements and Supplementary Data – Note 6 – Asset Retirement Obligations and Accrued Environmental Costs."

REGULATION

PacifiCorp conducts its business in conformance with a multitude of federal and state laws. PacifiCorp is also subject to the jurisdiction of public utility regulatory authorities in each of the states in which it conducts retail electric operations. These authorities regulate various matters, including customer rates, services, accounting policies and practices, allocation of costs by state, issuances of securities and other matters. In addition, PacifiCorp is a "licensee" and a "public utility" as those terms are used in the Federal Power Act and is therefore subject to regulation by the FERC as to accounting policies and practices, certain prices and other matters, including the terms and conditions of transmission service. Most of PacifiCorp's hydroelectric plants are licensed by the FERC as major projects under the Federal Power Act, and certain of these projects are licensed under the Oregon Hydroelectric Act.

Federal Regulatory Matters

After several years of active consideration, in July 2005 the United States Congress approved legislation making significant changes in federal energy policy. The Energy Policy Act of 2005, enacted in August 2005, repealed the Public Utility Holding Company Act of 1935 and transferred regulatory oversight of public utility holding companies from the SEC to the FERC. The Energy Policy Act of 2005 also contains provisions to encourage investment in renewable and lower-emission coal generation, provides financial incentives and removes regulatory barriers for developers of new electric transmission facilities, establishes a process for the creation and enforcement of mandatory electric reliability standards, and authorizes license applicants and other parties to seek less costly and more efficient conditions imposed on federal hydroelectric power licenses.

See "Item 8. Financial Statements – Note 10 – Commitments and Contingencies" which is incorporated by reference into this Item 1.

Several of PacifiCorp's hydroelectric plants are in some stage of the relicensing process with the FERC. PacifiCorp also has requested the FERC to allow decommissioning of four hydroelectric plants. The following summarizes the status of certain of these projects.

Hydroelectric Relicensing

Klamath hydroelectric project – (Klamath River, Oregon and California)

In February 2004, PacifiCorp filed with the FERC a final application for a new license to operate the 161.4-MW Klamath hydroelectric project. The FERC is scheduled to complete its required analysis by January 2007. The United States Departments of Interior and Commerce filed proposed licensing terms and conditions with the FERC in March 2006; PacifiCorp filed alternatives to the federal agencies' proposal and challenges to its factual assumptions in April 2006. PacifiCorp continues to participate in the mediated settlement discussions with state and federal agencies, Native American tribes and other stakeholders in an effort to reach a comprehensive agreement on project relicensing.

Lewis River hydroelectric projects – (Lewis River, Washington)

PacifiCorp filed new license applications for the 136.0-MW Merwin and 240.0-MW Swift No. 1 hydroelectric projects in April 2004. An application for a new license for the 134.0-MW Yale hydroelectric project was filed with the FERC in April 1999. However, consideration of the Yale application was delayed pending filing of the Merwin and Swift No. 1 applications so that the FERC could complete a comprehensive environmental analysis.

In November 2004, PacifiCorp executed a comprehensive settlement agreement with 25 other parties including state and federal agencies, Native American tribes, conservation groups, and local government and citizen groups to resolve, among the parties, issues related to the pending applications for new licenses for PacifiCorp's Merwin, Swift No. 1 and Yale hydroelectric projects. As part of this settlement agreement, PacifiCorp has agreed to implement certain protection, mitigation and enhancement measures prior to and during a proposed 50-year license period. However, these commitments are contingent on ultimately receiving a license from the FERC that is consistent with the settlement agreement and other required permits. Other required permits include biological opinions and a water quality certification. At the earliest, the FERC is expected to make a final decision in August 2006.

North Umpqua hydroelectric project – (North Umpqua River, Oregon)

In October 2005, the new FERC license for the 136.5-MW North Umpqua hydroelectric project became final under the terms of the North Umpqua Settlement Agreement. Prior to this date, the license had been effective, but not final, because environmental groups had challenged its legality before the FERC and in federal court. In September 2005, the Ninth Circuit Court of Appeals issued an order upholding the new license. Since the Ninth Circuit Court's order was not appealed within the allowed time, all legal challenges of the FERC license order have been exhausted and the license is final for purposes of recording liabilities. PacifiCorp is committed, over the 35-year life of the license, to fund approximately \$48.4 million for environmental mitigation and enhancement projects. As a result of the license becoming final, PacifiCorp recorded additional liabilities and intangible assets in October 2005 amounting to a present value of \$11.2 million. At March 31, 2006, the liability recorded for all North Umpqua obligations amounted to a present value of \$21.8 million.

Prospect hydroelectric project – (Rogue River, Oregon)

In June 2003, PacifiCorp submitted a final license application to the FERC for the Prospect Nos. 1, 2 and 4 hydroelectric projects, which total 36.8 MW. The FERC is expected to complete its required analysis and issue a new license before the end of October 2006.

Hydroelectric Decommissioning

Condit hydroelectric project – (White Salmon River, Washington)

In September 1999, a settlement agreement to remove the 9.6-MW Condit hydroelectric project was signed by PacifiCorp, state and federal agencies and non-governmental agencies. Under the original settlement agreement, removal was expected to begin in October 2006, for a total cost to decommission not to exceed \$17.2 million, excluding inflation. In early February 2005, the parties agreed to modify the settlement agreement so that removal will not begin until October 2008 for a total cost to decommission not to exceed \$20.5 million, excluding inflation. The settlement agreement is contingent upon receiving an amended FERC license and removal order that is not materially inconsistent with the amended settlement agreement and other regulatory approvals. PacifiCorp is in the process of acquiring all necessary permits, within the terms and conditions of the amended settlement agreement.

State Regulatory Actions

PacifiCorp is currently pursuing a regulatory program in all states, with the objective of keeping rates closely aligned to ongoing costs. A component of the regulatory program is the filing of Power Cost Adjustment Mechanisms ("PCAM"). PCAMs deal with changes in power costs occurring between rate cases. Power costs above or below the amounts built into rates are recovered from or returned to customers according to the provisions in the specific PCAM. The following discussion provides a state-by-state update.

Utah

In March 2006, PacifiCorp filed a general rate case with the UPSC related to increased investments in Utah due to growing demand for electricity. PacifiCorp is seeking an increase of \$197.2 million annually, or 17.1%. If approved by the UPSC, the increase would take effect in December 2006. In April 2006, PacifiCorp filed a revised case reflecting the effects of PacifiCorp's sale to MEHC. The revised case reduced the original increase requested from \$197.2 million to \$194.1 million. The active parties in the case have stipulated to a new schedule in the rate case which allows completion of preliminary audits and an opportunity for settlement discussions prior to the hearings set in July 2006 to determine the proper test year. In November 2005, PacifiCorp filed a PCAM application. The Utah Industrial Energy Consumer Group has filed a motion to dismiss the PCAM application based on lack of delegated legislative authority. PacifiCorp does not believe the motion has merit and will oppose the motion in its reply due June 9, 2006. The PCAM proceeding is running concurrently with the March 2006 general rate case.

Oregon

In April 2006, long-term special contracts for PacifiCorp's Klamath basin irrigation customers expired. Under the contracts, customers received power at rates less than PacifiCorp's average retail rates charged to other customers on general irrigation tariffs. Following expiration of these contracts, the OPUC issued an order authorizing the transition of Klamath basin irrigators to generally applicable cost-based rates.

In February 2006, PacifiCorp filed a general rate case request with the OPUC for approximately \$112.0 million, which represents a 13.2% overall increase. The request is related to investments in generation, transmission and distribution infrastructure and increases in fuel and general operating expenses, including the maintenance of low-cost but aging power plants. A procedural schedule has been established with a decision from the OPUC expected by December 2006.

In September 2005, Oregon's governor signed into law Senate Bill 408. This legislation is intended to address differences between income taxes collected by Oregon public utilities in retail rates and actual taxes paid by the utilities or consolidated groups in which utilities are included for income tax reporting purposes. This legislation authorizes an automatic adjustment to rates based on the taxes paid to governmental entities on or after January 1, 2006. The OPUC adopted a temporary rule in September 2005 to establish filing requirements for an annual tax report mandated by Senate Bill 408. The definitions adopted in the temporary rule would allocate a share of individual taxable losses of affiliate companies to the utility even when the consolidated tax group pays more taxes than the utility collects in retail rates. The temporary rule expired in March 2006. PacifiCorp is actively participating in the rulemaking process for adopting permanent rules required by Senate Bill 408.

In September 2005, the OPUC issued an order granting a general rate increase of \$25.9 million, or an average increase of 3.2%, effective October 2005. PacifiCorp filed its general rate case in November 2004, and following four partial stipulations with participating parties, PacifiCorp's requested revenue requirement increase was \$52.5 million. The OPUC's order reduced PacifiCorp's revenue requirement by \$26.6 million based on the OPUC's interpretation of Senate Bill 408. In October 2005, PacifiCorp filed with the OPUC a motion for reconsideration and rehearing of the rate order generally on the basis that the tax adjustment was not made in compliance with applicable law. With the motion, PacifiCorp also filed a deferred accounting application with the OPUC to track revenues related to the disallowed tax expenses. The OPUC granted PacifiCorp's motion for reconsideration and rehearing in December 2005 and is reconsidering whether Oregon Senate Bill 408 applies to the general rate case and, if it does, whether the tax adjustment ordered by the OPUC results in rates that are unconstitutional. A hearing and submissions of written briefs are scheduled to occur through May 2006. A decision is expected by summer 2006.

PacifiCorp filed an application in February 2005 for deferral of higher power costs incurred in calendar 2005 due to continuing poor hydroelectric conditions. PacifiCorp sought deferral of these costs to track for future recovery in rates. In

May 2005, this deferral application was suspended to allow parties to focus on a PCAM application filed by PacifiCorp in April 2005. Briefing in the PCAM proceeding was completed in January 2006 and a commission order is pending. In May 2006, the PCAM proceeding was stayed for 60 days at PacifiCorp's request.

Wyoming

In March 2006, the WPSC approved an agreement that settled the general rate case filed by PacifiCorp in October 2005 and a separate request filed by PacifiCorp in December 2005 to recover increased costs of net wholesale purchased power used to serve Wyoming customers. The agreement provides for an annual rate increase of \$15.0 million effective March 1, 2006, an additional annual rate increase of \$10.0 million effective July 1, 2006, a PCAM and an agreement by the parties to support a forecast test year in the next general rate case application.

Washington

In May 2005, PacifiCorp filed a general rate case request with the WUTC for approximately \$39.2 million annually. Hearings took place in January and February 2006 and this amount was reduced to approximately \$30.0 million. As part of the general rate case, PacifiCorp was also seeking to recover \$8.3 million in hydroelectric costs and was proposing that future hydroelectric and power cost volatility be recovered through a PCAM that was proposed as part of the general rate case. In April 2006, the WUTC issued an order denying PacifiCorp's request to increase retail rates. The WUTC determined that application of PacifiCorp's cost allocation methodology failed to satisfy the statutory requirements that resources must benefit Washington ratepayers.

In April 2006, PacifiCorp filed a petition for reconsideration of the order and requested an increase of not less than \$11.0 million. PacifiCorp also filed a limited rate request seeking a rate increase of approximately \$7.0 million, which represents a 2.99% increase in rates. PacifiCorp has requested that these dockets be consolidated so that the requested increase of not less than \$11.0 million can be achieved.

Idaho

In February 2006, PacifiCorp filed a notice of intent to file a general rate case with the IPUC. A general rate case may be filed between 60 and 120 days after filing such a notice. Negotiations with certain Idaho customers are ongoing and the successful conclusion of such negotiations may preclude the need for a rate case filing. If filed, the rate case will seek a rate increase in Idaho to be effective beginning January 2007.

In July 2005, the IPUC issued an order approving a settlement of PacifiCorp's general rate case filed in January 2005 and granting a stipulated rate increase of \$5.8 million, or an average increase of 4.8%, effective September 16, 2005. On that date, unrelated pre-existing surcharges expired, so the net effect to customers of the \$5.8 million base increase was an increase in rates of \$2.1 million annually, or an average increase of 1.7%.

California

In April 2006, long-term special contracts for PacifiCorp's Klamath basin irrigation customers expired. Under the contracts, customers received power at rates less than PacifiCorp's average retail rates charged to other customers on general irrigation tariffs. Following expiration of these contracts, the CPUC approved a joint proposal for a transition to standard tariff pricing.

In November 2005, PacifiCorp filed a general rate case with the CPUC for an increase of \$11.0 million annually, or an average increase of 15.6% related to increasing costs, including power costs and operating expenses, as well as significant needed capital investments. PacifiCorp's application also requests the implementation of an Energy Cost Adjustment Clause ("ECAC"), which like a PCAM allows for annual rate adjustments for changes in the level of net power costs, and a Post Test-Year Adjustment Mechanism ("PTAM"), which would allow annual rate adjustments for changes in operating costs and plant additions. These proposed adjustment mechanisms would operate outside the context of traditional general rate cases. In May 2006, PacifiCorp filed an update to this general rate case to account for the Klamath basin irrigation customers' transition plan and to update the filing for the expected cost savings as a result of the acquisition of PacifiCorp by MEHC. This updated filing resulted in a net requested average increase of \$12.8 million annually, or 18.9% for California customers.

ITEM 1A. RISK FACTORS

The following are certain risks and other factors to be considered when evaluating PacifiCorp. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for a discussion of additional important risks and other factors.

PacifiCorp is engaged in several large construction or expansion projects, the completion and expected cost of which is subject to significant risk, and PacifiCorp has significant funding needs related to its planned capital expenditures.

PacifiCorp is engaged in several large construction or expansion projects, including construction of a new generating facility, the Lake Side Power Plant, in Utah and various capital projects related to transmission and distribution. In addition, in connection with PacifiCorp's acquisition by MEHC, MEHC and PacifiCorp have committed to undertake several other capital expenditure projects, principally relating to environmental controls, transmission and distribution, renewable generating and other facilities. PacifiCorp expects to incur substantial construction, expansion and other capital expenditure costs over the next several years, including the recent regulatory commitments previously discussed. PacifiCorp depends upon both internal and external sources of liquidity to provide working capital and to fund capital requirements. If these funds are not available and/or if MEHC does not elect to provide any needed funding to PacifiCorp, PacifiCorp may need to postpone or cancel planned capital expenditures.

The completion of any or all of PacifiCorp's pending, proposed or future construction or expansion projects is subject to substantial risk and may expose PacifiCorp to significant costs. PacifiCorp's development or construction efforts on any particular project, or its capital expenditure program generally, may not be successful. If PacifiCorp is unable to complete the development or construction of any capital project, or if it decides to delay or cancel a project, it may not be able to recover its investment in that project.

Also, a proposed expansion or new project may cost more than planned to complete, and any excess costs, if related to a regulated asset and found to be imprudent, may not be recoverable in rates. The inability to successfully and timely complete a project or avoid unexpected costs may require PacifiCorp to perform under guarantees, and the inability to avoid unsuccessful projects or to recover any excess costs may materially affect PacifiCorp's cash flows and results of operations.

PacifiCorp is subject to certain operating uncertainties which may adversely affect its financial position, results of operations and cash flows.

The operation of complex electric utility systems (including transmission and distribution) and power generating facilities that are spread over a large geographic area involves many risks associated with operating uncertainties and events beyond PacifiCorp's control. These risks include the breakdown or failure of power generation equipment, transmission and distribution lines or other equipment or processes, unscheduled plant outages, work stoppages, transmission and distribution system constraints or outages, fuel shortages or interruptions, performance below expected levels of output, capacity or efficiency, the effects of changing government regulation, operator error and catastrophic events such as severe storms, fires, earthquakes, explosions or mining accidents. A casualty occurrence might result in injury or loss of life, extensive property damage or environmental damage. The realization of any of these risks could significantly reduce PacifiCorp's revenues or significantly increase its expenses, thereby adversely affecting results of operations. For example, if PacifiCorp cannot operate generation facilities at full capacity due to restrictions imposed by environmental regulations, its revenues could decrease due to decreased wholesale sales and its expenses could increase due to the need to obtain energy from higher-cost sources. Any reduction of revenues or increase in expenses resulting from the risks described above could decrease PacifiCorp's cash flows and weaken its financial position.

Furthermore, PacifiCorp's current and future insurance coverage may not be sufficient to replace lost revenues or cover repair and replacement costs, especially in light of recent catastrophic events affecting the insurance markets that make it more difficult or costly to obtain certain types of insurance.

Acts of sabotage and terrorism aimed at PacifiCorp's facilities, the facilities of its fuel suppliers or customers, or at regional transmission facilities could adversely affect PacifiCorp's business.

Since the September 11, 2001 terrorist attacks, the United States government has issued warnings that energy assets, specifically the nation's pipeline and electric utility infrastructure, may be the future targets of terrorist organizations. These developments have subjected PacifiCorp's operations to increased risks. Damage to PacifiCorp's assets, the assets of PacifiCorp's fuel suppliers or customers, or to regional transmission facilities inflicted by terrorist groups or saboteurs could

result in a significant decrease in revenues and significant repair costs, force PacifiCorp to increase security measures, cause changes in the insurance markets and cause disruptions of fuel supplies, energy consumption and markets, particularly with respect to natural gas and electric energy. Any of these consequences of acts of terrorism could materially affect PacifiCorp's results of operations and cash flows. Instability in the financial markets as a result of terrorism or war could also materially adversely affect PacifiCorp's ability to raise capital.

Recovery of costs by PacifiCorp is subject to regulatory review and approval, and the inability to recover costs may adversely affect PacifiCorp's revenues and cash flows.

PacifiCorp is subject to the jurisdiction of federal and state regulatory authorities. The FERC establishes tariffs under which PacifiCorp provides transmission service to the wholesale market and the retail market (in states allowing retail competition). The FERC also establishes both cost-based and market-based tariffs under which PacifiCorp sells electricity at wholesale and has licensing authority over most of PacifiCorp's hydroelectric generation facilities. In addition, the utility regulatory commissions in each state served by PacifiCorp independently determine the rates that PacifiCorp may charge its retail customers in those states.

Each state's rate-setting process is based upon the state utility commission's acceptance of an allocated share of PacifiCorp's total utility costs for its entire retail service territory. When different states adopt different methods to address this cost allocation issue, some costs may not be incorporated into rates in any state. Rate-making is also generally done on the basis of estimates of normalized costs, so if in a specific year realized costs are higher than normal, rates will not be sufficient to cover those costs. Each state utility commission generally sets rates based on a test year established according to that commission's policies. Certain states use a future test year or allow for escalation of historical costs. In the states in which PacifiCorp operates that use a historical test year, rate adjustments could lag cost increases, or decreases, by up to two years. This regulatory lag causes PacifiCorp to incur costs, including significant new investments, for which recovery through rates is delayed. In addition, each state commission decides what percentage return a utility will be permitted to earn on its equity. Each commission also decides what level of expense and investment is necessary, reasonable and prudent in providing service and may disallow and deny recovery in rates for any costs that do not meet this standard. For these reasons, as well as others (such as recently enacted legislation and the outcome of the recent rate order in Oregon limiting or denying the ability of a utility to recover tax expenses in rates), the rates authorized by the state regulators may not be sufficient to cover costs incurred to provide electrical services in any given period.

PacifiCorp is subject to energy regulation, legislation and political risks, and changes in regulations and rates or legislative developments may adversely affect its business, financial condition, results of operations and cash flows.

PacifiCorp is subject to comprehensive governmental regulation, including regulation by various federal, state and local regulatory agencies, which significantly influences PacifiCorp's operating environment, the prices it is allowed to charge customers, its capital structure, its costs and its ability to recover costs from customers. These regulatory agencies include the FERC, the EPA, and the public utility commissions in Utah, Oregon, Wyoming, Washington, Idaho and California.

PacifiCorp also conducts its businesses in conformance with a multitude of federal, state and local laws, which are subject to significant changes at any time. Changes in regulations or the imposition of additional regulations by any of these regulatory entities, as well as new legislation, could have a material adverse impact on PacifiCorp's results of operations. For example, such changes could result in increased retail competition in PacifiCorp's service territory, changes to the hydroelectric relicensing process under the Federal Power Act, encouragement of investments in renewable or lower-emission generation, the acquisition by a municipality or other quasi-governmental body of PacifiCorp's distribution facilities (by negotiation, legislation or condemnation or by a vote in favor of a Public Utility District under Oregon law), or a negative impact on PacifiCorp's current cost recovery arrangements. As another example, PacifiCorp could be adversely affected by Senate Bill 408, which was recently enacted in Oregon. That legislation, and the outcome of a recent rate case, which is currently under formal reconsideration, resulted in a reduction by the OPUC in the rates that PacifiCorp is currently permitted to charge to its Oregon customers, and in the future may limit the ability of PacifiCorp and other public utilities to recover future federal and state income tax expenses in Oregon retail rates. Unless Senate Bill 408 is amended, modified or repealed, or the pending rehearing of the rate case is resolved, in a manner satisfactory to PacifiCorp, such legislation and rules could have a material adverse effect upon PacifiCorp's results of operations and cash flows.

Several of PacifiCorp's hydroelectric projects are in some stage of the FERC relicensing process under the Federal Power Act, as several of PacifiCorp's long-term operating licenses have expired or will expire in the next few years. The relicensing process is a political and public regulatory process that involves sensitive resource issues and uncertainties. PacifiCorp cannot predict with certainty the requirements that may be imposed during the relicensing process, the economic impact of those requirements, whether new licenses will ultimately be issued or whether PacifiCorp will be willing to meet the relicensing requirements to continue operating its hydroelectric projects. Loss of hydroelectric resources or additional commitments arising from the relicensing process could increase PacifiCorp's operating costs or result in large capital expenditures that reduce earnings and cash flows.

In August 2005, the Energy Policy Act of 2005 was signed into law. That law potentially impacts many segments of the energy industry. The law directed the FERC to issue new regulations and regulatory decisions in areas such as electric system reliability, electric transmission expansion and pricing, regulation of utility holding companies, and enforcement authority. While the FERC has now issued rules and decisions on multiple aspects of the Energy Policy Act of 2005, the full impact of those decisions remains uncertain. As a result of past events affecting electric reliability, the Energy Policy Act of 2005 requires federal agencies, working together with non-governmental organizations charged with electric reliability responsibilities, to adopt and implement measures designed to ensure the reliability of electric transmission and distribution systems. The implementation of such measures could result in the imposition of more comprehensive or stringent requirements on PacifiCorp or other industry participants, which would result in increased compliance costs and could have a material adverse effect on PacifiCorp's business, financial position, results of operations and cash flows.

PacifiCorp is subject to market risk, counterparty performance risk and other risks associated with wholesale energy markets.

In general, market risk is the risk of adverse fluctuations in the market price of wholesale electricity and fuel, including natural gas and coal, which is compounded by energy volume changes affecting the availability of and/or demand for electricity and fuel. PacifiCorp purchases electricity and fuel in the open market or pursuant to short-term or variable-priced contracts as part of its normal operating business. If market prices rise, especially in a time when PacifiCorp requires larger than expected volumes that must be purchased at market or short-term prices, PacifiCorp may have significantly greater costs than anticipated. In addition, it may not be able to timely recover all, if any, of those increased costs through rate-making, due to retroactive rate-making prohibitions, unless deferred accounting or power cost recovery mechanisms have been previously authorized. Likewise, if electricity market prices drop in a period when PacifiCorp is a net seller of electricity in the wholesale market, PacifiCorp will earn less revenue, possibly to the extent of not recovering the cost of generating the electricity. Wholesale electricity prices are influenced primarily by factors throughout the western United States relating to supply and demand. Those factors include the adequacy of generating capacity, scheduled and unscheduled outages of generating facilities, hydroelectric generation levels, prices and availability of fuel sources for generation, disruptions or constraints to transmission facilities, weather conditions, economic growth, and changes in technology. Energy volume changes are caused by unanticipated changes in generation availability and/or changes in customer demand for power due to the weather, the economy and customer behavior. Although PacifiCorp plans for resources to meet its current and expected power delivery obligations, its power costs may be adversely impacted by market risk.

PacifiCorp is also exposed to risk related to performance of contractual obligations by its wholesale suppliers and customers. PacifiCorp relies on suppliers to deliver natural gas, coal and electricity in accordance with short- and long-term contracts. Failure or delay by suppliers to provide natural gas, coal or electricity pursuant to existing contracts could disrupt PacifiCorp's ability to deliver electricity and require it to incur additional expenses to meet the needs of its customers. In addition, as these contractual agreements end, PacifiCorp may not be able to continue to purchase natural gas, coal or electricity on terms equivalent to the terms of current contractual agreements. PacifiCorp relies on wholesale customers to take delivery of the energy they have committed to purchase and to pay for the energy on a timely basis. Failure of customers to take delivery may require PacifiCorp to find other customers to take the energy at lower prices than the original customers committed to pay. At certain times of year, prices paid by PacifiCorp for energy needed to satisfy its customers' demand for power may exceed the amounts PacifiCorp receives through retail rates from these customers. If the strategy PacifiCorp uses to economically hedge the exposure to these risks is ineffective, it could incur significant losses.

Weather conditions can adversely affect PacifiCorp's operating results.

Although PacifiCorp's service territory has historically experienced complementary seasonal customer power demand patterns as a result of the geographically diverse area of its operations, weather conditions can significantly affect operating results. For residential customers, within a given year, weather conditions are the dominant cause of usage variations from normal seasonal patterns. For example, in periods of unusually hot summer weather, residential customers tend to use significantly greater amounts of electricity to run air conditioners, which may substantially increase summer peak power demand. Changes in weather conditions and other natural events also impact customer behavior and power demand. Additionally, a portion of PacifiCorp's supply of electricity comes from hydroelectric projects that are dependent upon rainfall and snowpack. During or following periods of low rainfall or snowpack, PacifiCorp may obtain substantially less electricity from hydroelectric projects and must purchase greater amounts of electricity from the wholesale market or from other sources at market prices. Accordingly, variations in weather conditions can adversely affect PacifiCorp's results of operations through lower revenues and/or increased energy costs.

PacifiCorp is subject to environmental, health, safety and other laws and regulations that may adversely impact its business.

PacifiCorp is subject to a number of environmental, health, safety and other laws and regulations affecting many aspects of its present and future operations, including air emissions, water quality, endangered species, wastewater discharges, solid wastes, hazardous substances and safety matters. PacifiCorp may incur substantial costs and liabilities in connection with its operations as a result of these laws and regulations. In particular, the cost of future compliance with federal, state and local clean air laws, such as those that relate to addressing regional haze issues and those that require certain generators, including some of PacifiCorp's electric generating facilities, to limit emissions of nitrogen oxide, sulfur dioxide, carbon dioxide, mercury and other potential pollutants or emissions, may require PacifiCorp to make significant capital expenditures that may not be recoverable through future rates. In addition, these costs and liabilities may include those relating to claims for damages to property and persons resulting from PacifiCorp's operations. Regulatory changes, including new interpretations of existing laws and regulations, imposing more comprehensive or stringent requirements on PacifiCorp, to the extent such changes would result in increased compliance costs or additional operating restrictions, could have a material adverse effect on PacifiCorp's business, financial position, results of operations and cash flows.

Furthermore, regulatory compliance for existing facilities and the construction of new facilities is a costly and time-consuming process, and intricate and rapidly changing environmental regulations may require major expenditures for permitting and create the risk of expensive delays or material impairment of value if projects cannot function as planned due to changing regulatory requirements or local opposition.

In addition to operational standards, environmental laws also impose obligations to clean up or remediate contaminated properties or to pay for the cost of such remediation, often upon parties that did not actually cause the contamination. Accordingly, PacifiCorp may become liable, either contractually or by operation of law, for remediation costs even if the contaminated property is not presently owned or operated by it, or if the contamination was caused by third parties during or prior to its ownership or operation of the property. Given the nature of the past industrial operations conducted by PacifiCorp and others at its properties, all potential instances of soil or groundwater contamination may not have been identified, even for those properties where an environmental site assessment or other investigation has been conducted. Although PacifiCorp has accrued reserves for its known remediation liabilities, future events, such as changes in existing laws or policies or their enforcement, or the discovery of currently unknown contamination, may give rise to additional remediation liabilities which may be material. Any failure to recover increased environmental, health or safety costs incurred by PacifiCorp may have a material adverse effect on its business, financial position, results of operations and cash flows.

Poor performance of pension plan investments and other factors impacting pension plan costs could unfavorably impact PacifiCorp's liquidity and results of operations.

PacifiCorp's costs of providing non-contributory defined benefit pension plans depend upon a number of factors, including the rates of return on plan assets, discount rates, the level of interest rates used to measure the required minimum funding levels of the plans, future government regulation and PacifiCorp's required or voluntary contributions made to the plans. While PacifiCorp complies with the minimum funding requirements under federal law, as of March 31, 2006 its projected benefit obligations, which include the impact of expected future compensation increases, exceeded the value of plan assets by approximately \$513.6 million, including contributions made between the December 31, 2005 measurement date and March 31, 2006. Without sustained growth in the pension investments over time to increase the value of its pension plan

assets, and depending upon the other factors described above, PacifiCorp could be required to fund its pension plans with significant amounts of cash. Such cash funding obligations, as well as the impact of the other factors described above, could have a material impact on PacifiCorp's liquidity by reducing its cash flows and could negatively affect its results of operations.

A downgrade in PacifiCorp's credit ratings could negatively affect its ability to access capital and its ability to economically hedge in wholesale markets.

Changes in PacifiCorp's financial performance, capital structure, the regulatory environment in which it operates and other factors expose it to the risk of a credit ratings downgrade by Standard and Poor's or Moody's Investor Services, the principal ratings agencies that evaluate PacifiCorp's creditworthiness and that of its debt securities and preferred stock. Although PacifiCorp has no rating-downgrade triggers that would accelerate the maturity dates of its outstanding debt. A downgrade in its credit ratings could directly increase the interest rates and commitment fees on its revolving credit agreement. A ratings downgrade also may reduce the accessibility and increase the cost of PacifiCorp's commercial paper program, its principal source of short-term borrowing, and may result in the requirement that PacifiCorp post collateral under certain of its power purchase and other agreements. In addition, a credit ratings downgrade could allow counterparties in the wholesale electric, wholesale natural gas and energy derivatives markets to require PacifiCorp to post a letter of credit or other collateral, make cash prepayments, obtain a guarantee agreement or provide other mutually agreeable security. These consequences of a credit ratings downgrade could increase PacifiCorp's borrowing and operating costs.

PacifiCorp has a substantial amount of debt, which could adversely affect its ability to obtain future financing and limit its expenditures.

As of March 31, 2006, PacifiCorp had \$4.1 billion in total debt securities outstanding. Its principal financing agreements contain restrictive covenants that limit its ability to borrow funds, and any issuance of debt securities requires prior authorization from multiple state regulatory commissions. PacifiCorp expects that it will need to supplement cash generated from operations and availability under committed credit facilities with new issuances of long-term debt. However, if market conditions are not favorable for the issuance of long-term debt, or if an issuance of long-term debt would exceed contractual or regulatory limits, PacifiCorp may postpone planned capital expenditures, or take other actions, to the extent those expenditures are not fully covered by cash from operations or equity contributions from MEHC and not available under committed credit facilities.

MEHC may exercise its significant influence over PacifiCorp in a manner that would benefit MEHC to the detriment of PacifiCorp's creditors and preferred stockholders.

MEHC, through its subsidiary, owns all of PacifiCorp's common stock and therefore has significant influence over its business and any matters submitted for shareholder approval. In circumstances involving a conflict of interest between MEHC and PacifiCorp's creditors and preferred stockholders, MEHC could exercise its influence in a manner that would benefit MEHC to the detriment of PacifiCorp's creditors and preferred stockholders.

ITEM 1B. UNRESOLVED STAFF COMMENTS

No information is required to be reported pursuant to this item.

ITEM 2. PROPERTIES

PacifiCorp owns its principal properties in fee (except as indicated below), subject to defects and encumbrances that do not interfere materially with their use. Substantially all of PacifiCorp's electric utility properties are subject to the lien of PacifiCorp's Mortgage and Deed of Trust. See "Item 15. Exhibits, Financial Statement Schedules - Exhibit 4.1." PacifiCorp considers all of its properties to be well maintained, in good operating condition, and suitable for their intended purposes.

Headquarters/Offices

PacifiCorp's corporate offices consist of approximately 900,000 square feet of owned and leased office space located in several buildings in Portland, Oregon, and Salt Lake City, Utah. PacifiCorp's corporate headquarters are in Portland, but there are several executives and departments located in Salt Lake City. In addition to the corporate headquarters, PacifiCorp owns and leases approximately 1.2 million square feet of field office and warehouse space in various other locations in Utah, Oregon, Wyoming, Washington, Idaho and California. The field location square footage does not include offices located at PacifiCorp's generating plants.

Generation

PacifiCorp owns, or has an interest in, various hydroelectric, thermal and wind generating plants. A generator's nameplate rating is its full-load capacity (in megawatts) under normal operating conditions as defined by the manufacturer. The net capability is the maximum level a generator can operate at under specified conditions. The following table summarizes PacifiCorp's existing generating plants:

	Location	Energy Source	Unit Installation Date(s)	Nameplate Rating (MW)	Plant Net Capability (MW)
HYDROELECTRIC PLANTS (a)					
Swift No. 1 (b)	Cougar, WA	Lewis River	1958	240.0	264.0
Merwin	Ariel, WA	Lewis River	1931-1958	136.0	144.0
Yale	Amboy, WA	Lewis River	1953	134.0	165.0
Five North Umpqua Plants	Toketee Falls, OR	N. Umpqua River	1950-1956	136.5	138.5
John C. Boyle	Keno, OR	Klamath River	1958	90.4	94.0
Copco Nos. 1 and 2 Plants	Hornbrook, CA	Klamath River	1918-1925	47.0	54.5
Clearwater Nos. 1 and 2 Plants	Toketee Falls, OR	Clearwater River	1953	41.0	41.0
Grace	Grace, ID	Bear River	1908-1923	33.0	33.0
Prospect No. 2	Prospect, OR	Rogue River	1928	32.0	36.0
Cutler	Collingston, UT	Bear River	1927	30.0	29.1
Oneida	Preston, ID	Bear River	1915-1920	30.0	28.0
Iron Gate	Hornbrook, CA	Klamath River	1962	18.0	20.0
Soda	Soda Springs, ID	Bear River	1924	14.0	14.0
Fish Creek	Toketee Falls, OR	Fish Creek	1952	11.0	12.0
31 Minor Hydroelectric Plants (c)	Various	Various	1895-1990	90.7 *	86.3 *
Subtotal (51 Hydroelectric Plants)				1,083.6	1,159.4
THERMAL PLANTS					
Jim Bridger	Rock Springs, WY	Coal-Fired	1974-1979	1,541.1 *	1,413.4 *
Huntington	Huntington, UT	Coal-Fired	1974-1977	996.0	895.0
Dave Johnston	Glenrock, WY	Coal-Fired	1959-1972	816.8	762.0
Naughton	Kemmerer, WY	Coal-Fired	1963-1971	707.2	700.0
Hunter Nos. 1 and 2	Castle Dale, UT	Coal-Fired	1978-1980	727.9 *	662.0 *
Hunter No. 3	Castle Dale, UT	Coal-Fired	1983	495.6	460.0
Cholla No. 4	Joseph City, AZ	Coal-Fired	1981	414.0	380.0
Wyodak	Gillette, WY	Coal-Fired	1978	289.7 *	268.0 *
Carbon	Castle Gate, UT	Coal-Fired	1954-1957	188.6	172.0
Craig Nos. 1 and 2	Craig, CO	Coal-Fired	1979-1980	172.1 *	165.0 *
Colstrip Nos. 3 and 4	Colstrip, MT	Coal-Fired	1984-1986	155.6 *	149.0 *
Hayden Nos. 1 and 2	Hayden, CO	Coal-Fired	1965-1976	81.3 *	78.0 *
Currant Creek	Mona, UT	Natural Gas-Fired	2005-2006	566.9	523.0
Hermiston	Hermiston, OR	Natural Gas-Fired	1996	279.6 *	237.0 *
Gadsby Steam	Salt Lake City, UT	Natural Gas-Fired	1951-1952	257.6	235.0
Gadsby Peak	Salt Lake City, UT	Natural Gas-Fired	2002	141.0	120.0
Little Mountain	Ogden, UT	Natural Gas-Fired	1972	16.0	14.0
Camas Co-Gen	Camas, WA	Black Liquor	1996	61.5	22.0
Blundell (d)	Milford, UT	Geothermal	1984	26.1	23.0
Subtotal (17 Thermal Electric Plants)				7,934.6	7,278.4
WIND PLANT					
Foot Creek	Arlington, WY	Wind Turbines	1998	32.6 *	32.6 *
Subtotal (1 Other Plant)				32.6	32.6
Total Generating Plants (69)				9,050.8	8,470.4

* Jointly owned plants; amount shown represents PacifiCorp's share only.

(a) Hydroelectric project locations are stated by locality and river watershed.

(b) On April 21, 2002, the Cowlitz County Public Utility District-owned Swift No. 2 power canal failed, impacting the operations of the PacifiCorp-owned 240.0 MW Swift No. 1 hydroelectric facility. In June 2004, PacifiCorp and Cowlitz County Public Utility District, through an amendment to an existing power purchase agreement, agreed to a

mechanism for settling all claims and terms of rebuilding. Reconstruction of the canal is nearing completion and the project began operating on an interim basis in the three months ended March 31, 2006.

- (c) PacifiCorp has negotiated settlement agreements with resource agencies and other interested parties to decommission the American Fork, Condit, Cove Development and Powerdale hydroelectric plants, which have a combined net capability of 16.6 MW. These settlement agreements have been filed with the FERC and are pending further regulatory action.
- (d) As a result of the settlement agreement between MEHC, the Utah Committee of Consumer Services ("CCS"), a state utility consumer advocate, and Utah Industrial Energy Consumers, MEHC contributed to PacifiCorp, at no cost, MEHC's indirect 100.0% ownership interest in Intermountain Geothermal Company, which controls 69.3% of the steam rights associated with the geothermal field serving PacifiCorp's Blundell Geothermal Plant in Utah. Therefore, Intermountain Geothermal Company became a wholly owned subsidiary of PacifiCorp in March 2006, subsequent to the sale of PacifiCorp to MEHC.

In May 2002, PacifiCorp entered into a 15-year operating lease for an electric generation facility with West Valley Leasing Company, LLC, an indirect subsidiary of ScottishPower. The Utah facility consists of five generation units with an aggregate nameplate rating of 217.0 MW and a net plant capability of 202.0 MW. PacifiCorp, at its sole option, may terminate the lease, or purchase the facility, if written notice is provided to West Valley on or before December 1, 2006. If the termination option is exercised, the lease would end in May 2008.

Transmission and Distribution

PacifiCorp's generating facilities are interconnected through PacifiCorp's own transmission lines or by contract through the transmission lines of other transmission owners. Substantially all of PacifiCorp's generating plants and reservoirs are managed on a coordinated basis to obtain maximum load-carrying capability and efficiency. Portions of PacifiCorp's transmission and distribution systems are located:

- On property owned or leased by PacifiCorp;
- Under or over streets, alleys, highways and other public places, the public domain and national forests and state lands under franchises, easements or other rights that are generally subject to termination;
- Under or over private property as a result of easements obtained primarily from the record holder of title; or
- Under or over Native American reservations under grant of easement by the Secretary of Interior or lease by Native American tribes.

It is possible that some of the easements, and the property over which the easements were granted, may have title defects or may be subject to mortgages or liens existing at the time the easements were acquired.

At March 31, 2006, PacifiCorp owned, or participated in, an electric transmission and distribution system consisting of:

Nominal Voltage (In kilovolts)	Miles
Transmission Lines	
500	720
345	1,900
230	3,360
161	280
138	2,050
115	1,540
69	2,970
57	110
46	2,650
	15,580
Distribution Lines	
Less than 46	59,510
Total	75,090

At March 31, 2006, PacifiCorp owned 908 substations.

Mining

PacifiCorp believes that the respective coal reserves available to the Craig, Huntington, Hunter and Jim Bridger Plants, together with coal available under both long-term and short-term contracts with external suppliers, will be substantially sufficient to provide these plants with fuel that meets the Clean Air Act standards for their current economically useful lives. Blending of PacifiCorp-owned and contracted coal, together with electricity plant technologies for controlling sulfur and other emissions, are utilized to meet the applicable standards. PacifiCorp-owned plants held sufficient sulfur dioxide emission allowances to comply with the EPA Title IV requirements during the compliance year. The sulfur content of the coal reserves ranges from 0.30% to 0.94%, and the British Thermal Units value per pound of the reserves ranges from 8,600 to 12,400.

Coal reserve estimates are subject to adjustment as a result of the development of additional engineering and geological data, new mining technology and changes in regulation and economic factors affecting the utilization of such reserves. Recoverable coal reserves at March 31, 2006, based on PacifiCorp's most recent engineering studies, were as follows:

Location	Plant Served	Mining Method	Recoverable Tons (in Millions)
Craig, CO	Craig	Surface	48.0 (a)
Huntington & Castle Dale, UT	Huntington and Hunter	Underground	61.1 (b)
Rock Springs, WY	Jim Bridger	Surface/Underground	139.2 (c)

- (a) These coal reserves are leased and mined by Trapper Mining, Inc., a Delaware non-stock corporation operated on a cooperative basis, in which PacifiCorp has an ownership interest of 21.4%.
- (b) These coal reserves are leased by PacifiCorp and mined by a wholly owned subsidiary of PacifiCorp.
- (c) These coal reserves are leased and mined by Bridger Coal Company, a joint venture between Pacific Minerals, Inc. ("PMI") and a subsidiary of Idaho Power Company. PMI, a subsidiary of PacifiCorp, has a two-thirds interest in the joint venture. The Bridger mine is in the process of conversion from surface operation to primarily underground operation, while currently continuing production at its surface operations.

Recoverability by surface mining methods typically ranges from 90.0% to 95.0%. Recoverability by underground mining techniques ranges from 50.0% to 70.0%. Most of PacifiCorp's coal reserves are held pursuant to leases from the federal government through the Bureau of Land Management and from certain states and private parties. The leases generally have

multi-year terms that may be renewed or extended and require payment of rents and royalties. In addition, federal and state regulations require that comprehensive environmental protection and reclamation standards be met during the course of mining operations and upon completion of mining activities. See "Item 8. Financial Statements and Supplementary Data – Note 6 – Asset Retirement Obligations and Accrued Environmental Costs."

ITEM 3. LEGAL PROCEEDINGS

In October 2005, PacifiCorp was added as a defendant to a lawsuit originally filed in February 2005 in state district court in Salt Lake City, Utah by USA Power, LLC and its affiliated companies, USA Power Partners, LLC and Spring Canyon, LLC (collectively, "USA Power"), against Utah attorney Jody L. Williams and the law firm Holme, Roberts & Owen, LLP, who represent PacifiCorp on various matters from time to time. USA Power is the developer of a planned generation project in Mona, Utah called Spring Canyon, which PacifiCorp, as part of its resource procurement process, at one time considered as an alternative to the Currant Creek Power Plant. USA Power's complaint alleges that PacifiCorp misappropriated confidential proprietary information in violation of Utah's Uniform Trade Secrets Act and accuses PacifiCorp of breach of contract and related claims. USA Power seeks \$250.0 million in damages, statutory doubling of damages for its trade secrets violation claim, punitive damages, costs and attorneys' fees. PacifiCorp believes it has a number of defenses and intends to vigorously oppose any claim of liability for the matters alleged by USA Power. Furthermore, PacifiCorp expects that the outcome of this proceeding will not have a material impact on its consolidated financial position, results of operations or liquidity.

In October 2005, CCS filed a request for agency action with the UPSC. The request sought an order requiring PacifiCorp to return to Utah ratepayers certain monies collected in Utah rates for taxes, which the CCS alleges were improperly retained by PacifiCorp's parent company, PHI. The CCS has publicly announced it is seeking a refund of at least \$50.0 million to Utah ratepayers. Following PacifiCorp's sale to MEHC in March 2006, the CCS, MEHC and intervening party Utah Industrial Energy Consumers filed with the UPSC an agreement settling the claims made by the CCS. In exchange for dismissal of the claims, MEHC agreed to contribute to PacifiCorp, at no cost, MEHC's 100.0% ownership interest in Intermountain Geothermal Company, which controls 69.3% of the steam rights associated with the geothermal field serving PacifiCorp's Blundell Geothermal Plant in Utah. The settlement agreement has been approved by the UPSC, which dismissed the CCS request.

In May 2004, PacifiCorp was served with a complaint filed in the United States District Court for the District of Oregon by the Klamath Tribes of Oregon, individual Klamath Tribal members and the Klamath Claims Committee. The complaint generally alleges that PacifiCorp and its predecessors affected the Klamath Tribes' federal treaty rights to fish for salmon in the headwaters of the Klamath River in southern Oregon by building dams that blocked the passage of salmon upstream to the headwaters beginning in 1911. In September 2004, the Klamath Tribes filed their first amended complaint adding claims of damage to their treaty rights to fish for sucker and steelhead in the headwaters of the Klamath River. The complaint seeks in excess of \$1.0 billion in compensatory and punitive damages. In July 2005, the District Court dismissed the case and in September 2005 denied the Klamath Tribes' request to reconsider the dismissal. In October 2005, the Klamath Tribes appealed the District Court's decision to the Ninth Circuit Court of Appeals and briefing was completed in March 2006. Any final order will be subject to appeal. PacifiCorp believes the outcome of this proceeding will not have a material impact on its consolidated financial position, results of operations or cash flow.

In April 2004, PacifiCorp filed a complaint with the federal district court in Wyoming challenging the WPSC decision made in March 2003 to deny recovery of the Hunter No. 1 replacement power costs and certain deferred excess net power costs. The complaint was filed on the grounds that the decision violates federal law by denying PacifiCorp recovery in retail rates of its wholesale electricity and transmission costs incurred to serve Wyoming customers. In February 2006, PacifiCorp and certain parties intervening in its then-pending Wyoming general rate case reached a settlement of the terms of PacifiCorp's general rate case request. PacifiCorp also agreed to dismiss its federal lawsuit challenging the WPSC decision. The case was dismissed in May 2006.

In December 2004, a group of Utah customers filed a petition with the UPSC on behalf of themselves and other similarly situated customers seeking monetary compensation from PacifiCorp as a result of a severe winter storm in December 2003. This petition was substantially similar to an April 2004 petition that the UPSC resolved by consolidating customer requests with an ongoing regulatory winter storm inquiry. In May 2006, PacifiCorp reached a stipulation with the petitioners that resolved all claims in consideration of system maintenance and vegetation management commitments and additional credits for customers. The stipulation was approved by the UPSC on May 22, 2006.

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ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No information is required to be reported pursuant to this item.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

PacifiCorp is an indirect subsidiary of MEHC, which owns all shares of PacifiCorp's outstanding common stock. Therefore, there is no public market for PacifiCorp's common stock. Dividend information required by this item is included in "Item 8. Financial Statements and Supplementary Data – Quarterly Financial Data."

The state regulatory orders that authorized the acquisition by MEHC contain restrictions on PacifiCorp's ability to pay dividends to the extent that they would reduce PacifiCorp's common stock equity below specified percentages of defined capitalization.

As of March 31, 2006, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to PPW Holdings LLC or MEHC without prior state regulatory approval to the extent that it would reduce PacifiCorp's common stock equity below 48.25% of its total capitalization, excluding short-term debt and current maturities of long-term debt. After December 31, 2008, this minimum level of common equity declines annually to 44.0% after December 31, 2011. The terms of this commitment treat 50.0% of PacifiCorp's preferred stock outstanding prior to the acquisition of PacifiCorp by MEHC as common equity. As of March 31, 2006, PacifiCorp's actual common stock equity percentage, as calculated under this measure, exceeded the minimum threshold.

In addition, PacifiCorp is restricted from making any distributions to PPW Holdings LLC or MEHC if PacifiCorp's unsecured debt rating is BBB- or lower by Standard & Poor's Rating Services or Fitch Ratings or Baa3 or lower by Moody's Investor Service, as indicated by two of the three rating services. As of March 31, 2006, PacifiCorp's unsecured debt rating was BBB+ by Standard & Poor's Rating Services and Fitch Ratings and Baa1 by Moody's Investor Service.

PacifiCorp does not presently anticipate that it will declare dividends on common stock during the 12 months ending March 31, 2007.

PacifiCorp is also subject to maximum debt-to-total capitalization ratios under various debt agreements. For further discussion, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources."

ITEM 6. SELECTED FINANCIAL DATA (Unaudited)

(Millions of dollars, except per share and employee amounts)

	Years Ended March 31,				
	2006	2005	2004	2003	2002
Revenues:					
Electric Operations	\$ 3,896.7	\$ 3,048.8	\$ 3,194.5	\$ 3,082.4	\$ 3,341.1
Australian Operations	-	-	-	-	-
Other Operations (a)	-	-	-	-	12.6
Total	\$ 3,896.7	\$ 3,048.8	\$ 3,194.5	\$ 3,082.4	\$ 3,353.7
Income (loss) from operations:					
Electric Operations	\$ 792.0	\$ 656.4	\$ 617.9	\$ 488.9	\$ 598.6
Australian Operations	-	-	-	-	27.4
Other Operations (a)	-	-	-	-	15.0
Total	\$ 792.0	\$ 656.4	\$ 617.9	\$ 488.9	\$ 641.0
Net income	\$ 360.7	\$ 251.7	\$ 248.1	\$ 140.1	\$ 327.3
Earnings on common stock:					
Continuing operations					
Electric Operations	\$ 358.6	\$ 249.6	\$ 245.7	\$ 134.7	\$ 232.8
Australian Operations	-	-	-	-	27.4
Other Operations (a)	-	-	-	-	20.5
Total	358.6	249.6	245.7	134.7	280.7
Discontinued operations (b)	-	-	-	-	146.7
Cumulative effect of accounting change (c) (d) (e)	-	-	(0.9)	(1.9)	(112.8)
Total earnings on common stock	\$ 358.6	\$ 249.6	\$ 244.8	\$ 132.8	\$ 314.6
Common dividends declared per share	\$ 0.53	\$ 0.62	\$ 0.51	\$ -	\$ 0.81
Common dividends paid per share	\$ 0.53	\$ 0.62	\$ 0.51	\$ -	\$ 1.00
At March 31,					
	2006	2005	2004	2003	2002
Capitalization:					
Short-term debt	\$ 184.4	\$ 468.8	\$ 124.9	\$ 25.0	\$ 177.5
Long-term debt, including current maturities	3,937.9	3,898.9	3,760.2	3,554.3	3,698.3
Preferred Securities of Trusts	-	-	-	341.8	341.5
Preferred stock subject to mandatory redemption	45.0	52.5	60.0	66.7	74.2
Preferred stock	41.3	41.3	41.3	41.3	41.3
Common equity	4,010.5	3,335.8	3,278.7	3,194.4	2,891.9
Total Capitalization	\$ 8,219.1	\$ 7,797.3	\$ 7,265.1	\$ 7,223.5	\$ 7,224.7
Total assets	\$ 12,731.3	\$ 12,520.9	\$ 11,677.1	\$ 11,695.8	\$ 10,234.9
Total employees	6,750	6,654	6,507	6,140	6,287

- (a) Other Operations includes the activities of PacifiCorp Financial Services, Inc. and PacifiCorp Group Holdings Company, until their transfer in February 2002 to PacifiCorp's former parent company, PHI.
- (b) The year ended March 31, 2002 includes the collection of a contingent note receivable relating to the discontinued operations of a former mining and resource development business, NERCO, Inc.
- (c) The year ended March 31, 2004 reflects the effect of implementation of Statement of Financial Accounting Standards ("SFAS") No. 143, *Asset Retirement Obligations* ("SFAS No. 143").
- (d) The year ended March 31, 2003 reflects the effect of the implementation of the Derivatives Implementation Group (the

"DIG") Revised Issue C15, *Normal Purchases and Normal Sales Exception for Certain Option-Type Contracts and Forward Contracts in Electricity* ("Issue C15"), and Issue C16, *Applying the Normal Purchases and Normal Sales Exception to Contracts that Combine a Forward Contract and a Purchased Option Contract* ("Issue C16").

- (e) The year ended March 31, 2002, reflects the effect of the implementation of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended, ("SFAS No. 133"). Upon receiving regulatory approval, PacifiCorp has subsequently recorded the effects of unrealized gains or losses on certain long-term contracts as regulatory assets and liabilities.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

The Management's Discussion and Analysis should be read in conjunction with the Consolidated Financial Statements.

PacifiCorp is a regulated electricity company serving approximately 1.6 million retail customers in service territories aggregating approximately 136,000 square miles in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho and California. The regulatory commissions in each state approve rates for retail electric sales within their respective states. PacifiCorp also sells electricity on the wholesale market to public and private utilities, energy marketing companies and to incorporated municipalities. Wholesale activities are regulated by the FERC. PacifiCorp owns, or has interests in, 69 thermal, hydroelectric and wind generating plants, with an aggregate nameplate rating of 9,050.8 MW and plant net capability of 8,470.4 MW. The FERC and the six state regulatory commissions also have authority over the construction and operation of PacifiCorp's electric generation facilities. PacifiCorp delivers electricity through approximately 59,510 miles of distribution lines and approximately 15,580 miles of transmission lines.

Sale of PacifiCorp

As described in "Item 1. Business – Overview – Ownership by MEHC; Sale of PacifiCorp," MEHC completed its acquisition of PacifiCorp from ScottishPower and PHI on March 21, 2006. MEHC purchased all PacifiCorp common stock for approximately \$5.1 billion in cash.

In January through March 2006, the state commissions in all six states where PacifiCorp has retail customers approved PacifiCorp's sale to MEHC. The approvals were conditioned on a number of regulatory commitments, including expected financial benefits in the form of reduced corporate overhead and financing costs, certain mid- to long-term capital and other expenditures of significant amounts and a commitment not to seek utility rate increases attributable solely to the change in ownership. The capital and other expenditures proposed by MEHC and PacifiCorp include:

- Approximately \$812.0 million in investments (generally to be made over several years following the sale and subject to subsequent regulatory review and approval) in emissions reduction technology for PacifiCorp's existing coal plants, which, when coupled with the use of reduced emissions technology for anticipated new coal-fueled generation, is expected to result in significant reductions in emissions rates of sulfur dioxide, nitrogen oxide and mercury and to avoid an increase in the carbon dioxide emissions rate;
- Approximately \$519.5 million in investments (to be made over several years following the sale and subject to subsequent regulatory review and approval) in PacifiCorp's transmission and distribution system that would enhance reliability, facilitate the receipt of renewable resources and enable further system optimization; and
- The addition of 400.0 MW of cost-effective renewable resources to PacifiCorp's generation portfolio by December 31, 2007, including 100.0 MW of cost-effective wind resources by March 21, 2007.

The commitments approved by the state commissions also include credits that will reduce retail rates generally through 2010 to the extent that PacifiCorp does not achieve identified cost reductions or demonstrate mitigation of certain risks to customers. The maximum potential value of these rate credits to customers in all six states is \$142.5 million. PacifiCorp and MEHC have made additional commitments to the state commissions that limits the dividends PacifiCorp can make to MEHC or its affiliates. As of March 31, 2006, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to PPW Holdings LLC or MEHC without prior state regulatory approval to the extent that it would reduce PacifiCorp's common stock equity below 48.25% of its total capitalization, excluding short-term debt and current maturities of long-term debt. After December 31, 2008, this minimum level of common equity declines annually to 44.0% after December 31, 2011. The terms of this commitment treat 50.0% of PacifiCorp's preferred stock outstanding prior to the acquisition of PacifiCorp by MEHC

as common equity. As of March 31, 2006, PacifiCorp's actual common stock equity percentage, as calculated under this measure, exceeded the minimum threshold.

Forward-Looking Statements

This report includes forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical fact, made in this report are forward-looking. When used in this Management's Discussion and Analysis of Financial Condition and Results of Operations and elsewhere in this report, the words "will," "may," "could," "believes," "estimates," "expects," "anticipates," "forecasts," "plans," "intends," "projected," "potential" and variations of such words and similar expressions are intended to identify forward-looking statements. Forward-looking statements included in this report relate to, among other matters, the effect on PacifiCorp of the following: regulatory commitments related to PacifiCorp's sale to MEHC; recently enacted Oregon Senate Bill 408; potential adjustment of regulatory rates to cover costs; growth of retail customers and demand; the impact of new accounting standards or accounting policy changes; the outcome of litigation or regulatory proceedings; the timing of future regulatory filings; environmental laws; federal energy policy and legislation; capital expenditure levels; results from, and the timing of, the construction or repair of generating facilities; hydroelectric relicensing and decommissioning activities; electricity outages; pension and other postretirement contributions; outcome of tax proceedings; growth in customers and usage; levels of hydroelectric and thermal generation; sufficiency of PacifiCorp's available funds to meet its liquidity needs and future financing; off-balance sheet arrangements; the effect of risk management measures, including use of financial derivatives to manage and mitigate interest rate exposure; fluctuations in forward prices for electricity and natural gas; and the efficiency and effectiveness of PacifiCorp's resource and fuel procurement. Forward-looking statements reflect management's current expectations, plans or projections and are inherently uncertain. There can be no assurance the results predicted will be realized. Actual results may vary from those represented by the forecasts, and those variations may be material. The following are among the factors, in addition to those set forth under "Item 1A. Risk Factors," that could cause actual results to differ materially from the forward-looking statements:

- The outcome of general rate cases and other proceedings conducted by regulatory commissions or other governmental and legal bodies;
- Changes in prices and availability (for both purchases and sales) of wholesale electricity, natural gas and other fuel sources and other changes in operating costs that could affect PacifiCorp's cost recovery;
- Changes in regulatory requirements or other legislation, including the recently enacted federal Energy Policy Act of 2005, legislation or regulatory outcomes limiting the ability of public utilities to recover income tax expense in retail rates such as Senate Bill 408, industry restructuring and deregulation initiatives;
- Industrial, commercial and residential customer growth and demographic patterns in PacifiCorp's service territories;
- Economic trends that could impact electricity usage;
- Changes in weather conditions and other natural events that could affect customer demand or electricity supply;
- A high degree of variance between actual and forecasted load and prices that could impact the hedging strategy and costs to balance electricity load and supply;
- Hydroelectric conditions, as well as natural gas and coal production and price levels, that could have a significant impact on electric capacity and cost and on PacifiCorp's ability to generate electricity;
- Performance of PacifiCorp's generation facilities, including the level of planned and unplanned outages;
- The cost, feasibility and eventual outcome of hydroelectric facility relicensing proceedings;
- Changes in, and compliance with, environmental and endangered species laws, regulations, decisions and policies that could increase operating and capital improvement costs, reduce plant output and/or delay plant construction;
- Changes resulting from MEHC ownership;
- The impact of new accounting pronouncements or changes in current accounting estimates and assumptions on financial position and results of operations;

- The impact of interest rates, investment performance and increases in health care costs on pension and post-retirement expense;
- Continued availability of funds to meet liquidity requirements;
- The impact of any required performance under off-balance sheet arrangements;
- Financial condition and creditworthiness of significant customers and suppliers;
- The impact of financial derivatives used to mitigate or manage interest rate risk and volume and price risk due to weather extremes;
- Changes in PacifiCorp's credit ratings;
- Timely and appropriate completion of PacifiCorp's resource procurement process, unanticipated construction delays, changes in costs, receipt of required permits and authorizations, ability to fund resource projects and other factors that could affect future generation plants and infrastructure additions;
- Other risks or unforeseen events, including wars, the effects of terrorism, embargos and other catastrophic events; and
- Other business or investment considerations that may be disclosed from time to time in SEC filings or in other publicly disseminated written documents.

Any forward-looking statements issued by PacifiCorp should be considered in light of these factors. PacifiCorp does not intend to update or revise any forward-looking statements to reflect actual results, changes in assumptions or changes in other factors affecting such forward-looking statements or if PacifiCorp later becomes aware that these assumptions are not likely to be achieved.

Accounting Matters

Critical Accounting Estimates and Related Policies

The preparation of consolidated financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the results of operations and the reported amounts of assets and liabilities in the Consolidated Financial Statements. The estimates and assumptions may change as time passes and accounting guidance evolves. Management bases its estimates and assumptions on historical experience and on other various judgments that it believes are reasonable at the time of application. Changes in these estimates and assumptions could have a material impact on the Consolidated Financial Statements. If estimates and assumptions are different than the actual amounts recorded, adjustments are made in subsequent periods to take into consideration the new information. Critical accounting estimates, in addition to certain less significant accounting estimates, are discussed with senior members of management and PacifiCorp's Board of Directors, as appropriate, and were previously disclosed to the ScottishPower Audit Committee and from March 21, 2006 are disclosed to the MEHC Audit Committee. Those estimates that management considers critical are described below.

Derivatives

On April 1, 2001, PacifiCorp adopted SFAS No. 133, as amended. PacifiCorp uses derivative instruments (primarily forward purchases and sales) to manage the commodity price risk inherent in its fuel and electricity obligations, as well as to optimize the value of power generation assets and related contracts. PacifiCorp also enters into short-term energy derivatives on a limited basis for arbitrage purposes to take advantage of opportunities arising from market inefficiencies.

SFAS No. 133 requires that derivative instruments be recorded on the balance sheet at fair value. The fair values of derivative instruments are determined using forward price curves. Forward price curves represent PacifiCorp's estimates of the prices at which a buyer or seller could contract today for delivery or settlement of a commodity at

future dates. PacifiCorp bases its forward price curves upon market price quotations when available and uses internally developed, modeled prices when market quotations are unavailable. In general, PacifiCorp estimates the fair value of a contract by calculating the present value of the difference between the contract and the applicable

forward price curve.

Price quotations for certain major electricity trading hubs are generally readily obtainable for the first six years and, therefore, PacifiCorp's forward price curves for those locations and periods reflect observable market quotes. However, in the later years or for locations that are not actively traded, forward price curves must be estimated in other ways. For short-term contracts at less actively traded locations, prices are modeled based on observed historical price relationships with actively traded locations. For long-term contracts extending beyond six years, the forward price curve is based upon the use of a fundamentals model (cost-to-build approach), due to the limited information available. Factors used in the fundamentals model include the forward prices for the commodities used as fuel to generate electricity, the expected system heat rate (which measures the efficiency of power plants in converting fuel to electricity) in the region where the purchase or sale takes place and a fundamentals forecast of expected spot prices for a commodity in a region based on modeled supply of and demand for the commodity in the region. The assumptions in these models are critical, since any changes in assumptions could have a significant impact on the fair value of the contract.

Despite the large volume of implementation guidance, SFAS No. 133 and the supplemental guidance do not provide specific guidance on all contract issues. As a result, significant judgment must be used in applying SFAS No. 133 and its interpretations.

Pensions and Other Postretirement Benefits

PacifiCorp sponsors defined benefit pension plans that cover the majority of its employees. In addition, certain bargaining unit employees participate in a joint trust plan to which PacifiCorp contributes. PacifiCorp accounts for these plans in accordance with SFAS No. 87, *Employers' Accounting for Pensions* ("SFAS No. 87"). PacifiCorp accounts for its other postretirement benefit plan in accordance with SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other than Pensions* ("SFAS No. 106"). The expense and benefit obligations relating to PacifiCorp's pension and other postretirement benefit plans are based on actuarial valuations. Inherent in these valuations are key assumptions, including discount rates, expected returns on plan assets, compensation increases, PacifiCorp contributions and health care cost trend rates. These actuarial assumptions are reviewed annually and modified as appropriate. The effect of modifications is generally amortized over future periods. PacifiCorp believes that the assumptions utilized in recording obligations under the plans are reasonable based on prior experience, market conditions and the advice of plan actuaries. However, actual results may differ from such assumptions.

The PacifiCorp Retirement Plan (the "Retirement Plan") currently has assets with a fair value that is less than the accumulated benefit obligation, primarily due to declines in the equity markets during calendar years 2000 through 2002 and lower discount rates. PacifiCorp recognized a minimum pension liability in the three months ended March 31, 2003, and continues to recognize this liability at March 31, 2006. The liability adjustment did not affect the consolidated results of operations. PacifiCorp requested and received accounting orders from the regulatory commissions in Utah, Oregon, Wyoming and Washington to classify most of this charge as a Regulatory asset instead of a charge to Other comprehensive income. This increase to Regulatory assets was adjusted as of March 31, 2006 and 2005 and will be adjusted in future periods as the difference between the fair value of the trust assets and the accumulated benefit obligation changes. PacifiCorp has determined that costs related to SFAS No. 87 for the Retirement Plan are currently recoverable in rates.

PacifiCorp's contributions to the Retirement Plan have exceeded the minimum funding requirements of the Employee Retirement Income Security Act ("ERISA"). PacifiCorp made \$63.7 million in cash contributions to the Retirement Plan during the year ended March 31, 2006, including those contributions made between the December 31, 2005 measurement date and March 31, 2006, and made \$61.6 million in cash contributions to the Retirement Plan during the year ended March 31, 2005. In April 2006, PacifiCorp contributed \$72.7 million to its Retirement Plan and expects to contribute another \$11.0 million to its pension plans in the 12 months ending March 31, 2007. PacifiCorp is funding the Retirement Plan at what it believes to be an adequate level, but it currently expects to make larger cash contributions in the future due to its underfunded pension obligation and ERISA requirements. Such cash requirements could be material to PacifiCorp's cash flows. PacifiCorp believes it has adequate access to capital resources to support these contributions. As of March 31, 2006, PacifiCorp's underfunded status of the pension plans was \$513.6 million, including contributions made between the December 31, 2005 measurement date and March 31, 2006. For further details, see "Item 8. Financial Statements – Note 17 – Employee Benefits," which are incorporated by reference into this Item 7.

PacifiCorp discounted its future pension and other postretirement plan obligations using a rate of 5.75% at March 31, 2006 and 2005. Thus, the discount rate used for PacifiCorp's expense during the 12 months ended March 31, 2006 was 5.75% and the discount rate that will be used for PacifiCorp's expense during the 12 months ending March 31, 2007 will also be 5.75%. PacifiCorp chooses a discount rate based upon high quality fixed-income investment yields. The pension and other postretirement benefit liabilities, as well as expenses, increase as the discount rate is reduced.

At March 31, 2006, PacifiCorp assumed that the pension and other postretirement assets would generate a long-term rate of return of 8.50% for the 12 months ending March 31, 2007 compared to an assumed rate of return of 8.75% for the year ended March 31, 2006. In establishing its assumption as to the expected return on assets, PacifiCorp reviews the expected asset allocation and develops return assumptions for each asset class based on historical performance and independent advisors' forward-looking views of the financial markets. Pension and other postretirement benefit expenses increase as the expected rate of return on Retirement Plan and other postretirement benefit plan assets decreases.

Based on the above assumptions, PacifiCorp expects to record pension expense of \$71.0 million for the 12 months ending March 31, 2007, compared to \$63.8 million for the year ended March 31, 2006.

The following table reflects the sensitivities of the March 31, 2006 disclosures and the projected pension expense for the 12 months ending March 31, 2007 associated with a change in certain actuarial assumptions by the indicated percentage:

(Millions of dollars)				
Actuarial Assumption	Change in Assumption	Impact on Projected Benefit Obligation Increase (Decrease)	Impact on Minimum Pension Liability Increase (Decrease)	Impact on Annual Pension Cost Increase (Decrease)
Expected long-term return on plan assets	(0.5) %	\$ -	\$ -	\$ 4.2
Expected long-term return on plan assets	0.5	-	-	(4.2)
Discount rate	(0.5)	89.4	77.9	8.9
Discount rate	0.5	(83.7)	(73.0)	(8.7)

PacifiCorp expects to record other postretirement benefit expense of \$36.6 million for the 12 months ending March 31, 2007, compared to \$29.9 million for the year ended March 31, 2006. PacifiCorp has determined that costs related to SFAS No. 106 for other postretirement benefits are currently recoverable in rates. PacifiCorp contributed \$29.7 million for the year ended March 31, 2006 and \$24.9 million for the year ended March 31, 2005 to the funding vehicles for its postretirement benefit plan. PacifiCorp expects to contribute \$36.6 million to its other postretirement benefit plans for the 12 months ending March 31, 2007. As of March 31, 2006, PacifiCorp's underfunded status of the other postretirement benefit plans was \$260.6 million, including contributions made between the December 31, 2005 measurement date and March 31, 2006. For further details, see "Item 8. Financial Statements – Note 17 – Employee Benefits," which are incorporated by reference into this Item 7.

In valuing its accumulated postretirement benefit obligation, PacifiCorp must make an assumption regarding future changes in health care costs. Assumed changes impact the obligation and expense as follows:

(Millions of dollars)	Impact on Accumulated Postretirement Benefit Obligation Increase (Decrease)	Impact on Annual Other Postretirement Benefit Cost Increase (Decrease)
Assumed health care cost trend rates		
One percentage point increase	\$ 43.7	\$ 6.2
One percentage point decrease	(35.5)	(5.1)

Regulation

PacifiCorp prepares its Consolidated Financial Statements in accordance with SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation* ("SFAS No. 71"). SFAS No. 71 requires PacifiCorp to reflect the impact of regulatory decisions in its Consolidated Financial Statements and requires that certain costs be deferred on the

balance sheet until matching revenues can be recognized. Similarly, certain items may be deferred as regulatory liabilities and are amortized to the Consolidated Statements of Income as rates to customers are reduced or costs previously recovered in rates are actually incurred. SFAS No. 71 provides that regulatory assets may be capitalized if it is probable that future revenue in an amount at least equal to the capitalized costs will result from their treatment as allowable costs for rate-making purposes. In addition, the rate action should permit recovery of the specific previously incurred cost rather than provide for expected levels of similar future costs.

PacifiCorp is subject to state and federal regulation. In the event of deregulation, PacifiCorp would seek recovery of its net regulatory assets and any additional stranded costs. If unsuccessful, the unrecoverable portion of its net regulatory assets would be written-off and PacifiCorp would evaluate the remaining assets on its balance sheet for impairment in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. PacifiCorp is unable to predict the likelihood of deregulation and its future impacts.

At March 31, 2006, PacifiCorp had recorded specifically identified regulatory assets, net of regulatory liabilities, totaling \$174.3 million. In the event PacifiCorp stopped applying SFAS No. 71 at March 31, 2006, an after-tax loss of approximately \$108.2 million would be recognized.

Unbilled Revenues

Electricity sales to retail customers are determined based on meter readings taken throughout the month. PacifiCorp accrues an estimate of unbilled revenues, net of estimated line losses, each month for electric service provided after the meter reading date to the end of the month. The unbilled revenue estimate is based on three components: PacifiCorp's total electricity delivered during the month, assignment of unbilled revenues to customer type and valuation of the unbilled energy. Factors involved in the estimation of consumption and line losses relate to weather conditions, amount of natural light, historical trends, economic impacts and customer type. Valuation of unbilled energy is based on estimating the average price for the month for each customer type. These estimates can vary significantly from period to period depending on monthly weather patterns, customers' space heating and cooling, production levels due to economic activity or changing irrigation patterns due to precipitation conditions.

Differences between estimated unbilled revenue and the subsequently billed revenue would most likely occur due to the variation in assignments of customer usage by revenue class and jurisdiction or variations from estimates of line losses due to changes related to line capacity utilization and weather conditions. At March 31, 2006, the amount accrued for unbilled revenues was \$148.2 million.

Contingencies

PacifiCorp follows SFAS No. 5, *Accounting for Contingencies* ("SFAS No. 5"), to determine accounting and disclosure requirements for contingencies. According to SFAS No. 5, an estimated loss from a contingency shall be charged to income if (i) it is probable that an asset has been impaired or a liability has been incurred at the date of the financial statements, and (ii) the amount of the loss can be reasonably estimated. Disclosure in the notes to the financial statements is required for loss contingencies not meeting both of these conditions if there is a reasonable possibility that a loss may have been incurred. Gain contingencies are not recorded until realized.

PacifiCorp operates in a highly regulated environment. Governmental bodies such as the FERC, state regulatory commissions, the SEC, Internal Revenue Service, Department of Labor, the EPA and others have authority over various aspects of PacifiCorp's business operations and public reporting. Reserves are established when required based upon management's best judgment. Appropriate disclosures are made regarding litigation, tax matters, environmental issues, assessments and creditworthiness of customers or counterparties, among others. The evaluation of these contingencies is performed by various specialists inside and outside of PacifiCorp. Accounting for contingencies requires significant judgment by management regarding the estimated probabilities and ranges of exposure to potential loss. Management's assessment of PacifiCorp's exposure to contingencies could change as new developments occur or more information becomes available. The outcome of the contingencies could vary significantly and could materially impact PacifiCorp's consolidated financial position, results of operations and cash flows. Management has used its best judgment in applying SFAS No. 5 to these matters.

New Accounting Standards

For new accounting standards, see "Item 8. Financial Statements – Note 1 – Summary of Significant Accounting Policies." which are incorporated by reference into this Item 7.

RESULTS OF OPERATIONS

Overview

PacifiCorp's net income was \$360.7 million for the year ended March 31, 2006 compared to \$251.7 million for the year ended March 31, 2005. Significant factors affecting results for the year ended March 31, 2006 included higher retail prices approved by regulators, customer growth and a net increase in customer usage, as well as increased generation output, partially offset by higher operations and maintenance expense, including employee-related expenses, and the impact of increased fuel prices. The increase in net income was also significantly affected by a \$78.4 million increase in net unrealized gains on wholesale sales, wholesale purchase and fuel contracts primarily due to movements in forward prices.

Retail energy sales volumes grew by 2.4% in the year ended March 31, 2006 compared to the year ended March 31, 2005. PacifiCorp's number of retail customers has been increasing by approximately 2.0% annually over the past four years. This trend is expected to continue for the foreseeable future. Increased customer usage, which also contributed to the higher volumes, is generally affected by economic and weather conditions, consumer trends and energy savings programs.

In recent years, PacifiCorp has filed general rate cases in all six states where it has retail customers, with the objective of keeping customer rates closely aligned to ongoing operating costs and to recover costs of capital investments. PacifiCorp may make additional general rate case filings in certain states over the coming year. PacifiCorp's regulatory program has also included various other filings such as proposed power cost adjustment mechanisms. See "Item I. Business – Regulation" for developments regarding state regulatory issues and pending rate case filings.

PacifiCorp relies on electricity generated by its thermal facilities to meet a substantial portion of its customer load. PacifiCorp's maintenance and overhaul programs are utilized to facilitate reliable generation availability at its thermal facilities through planned outages, but PacifiCorp still may experience unplanned outages. During these outage periods, other owned generation or wholesale market purchases are utilized to balance system requirements. PacifiCorp's hydroelectric facilities are utilized as lower-cost sources of electricity generation but are dependent upon precipitation, temperatures and other variables. Wholesale energy sales and purchase contracts are utilized to balance PacifiCorp's physical excess or shortage of net electricity and are impacted by the movements in the market prices of both natural gas and electricity. While increased thermal generation output reduces the need for wholesale market purchases, its financial impact can be significantly affected by market prices for coal and natural gas.

Output from PacifiCorp's thermal plants increased by 1,055,579 megawatt-hours ("MWh"), or 2.2%, during the year ended March 31, 2006 compared to the year ended March 31, 2005. The Currant Creek Power Plant commenced full combined-cycle operation in March 2006, adding 523.0 MW of capability to PacifiCorp's generation portfolio. Construction of the Lake Side Power Plant is progressing and is expected to begin operations in May 2007. Once in full commercial operation, the Lake Side Power Plant will add an estimated capability of 550.0 MW to meet expected future energy needs.

Output from PacifiCorp-owned hydroelectric facilities for the year ended March 31, 2006 increased by 1,074,640 MWh, or 35.0%, as compared to the year ended March 31, 2005. This increase was primarily attributable to current-year water conditions that, although slightly lower than normal, improved relative to the prior-year period. PacifiCorp's hydroelectric generation was 98.2% of normal for the year ended March 31, 2006, based on a 30-year average. Hydroelectric generation has been below normal for the past six years. PacifiCorp cannot predict if this trend will continue in future years.

PacifiCorp continues to experience increasing employee costs primarily due to rising healthcare and pension costs,

additional employees and normal annual salary and wage increases. Pension costs continue to increase as a result of previous years' decreases in discount rates, which result in increases in PacifiCorp's projected benefit obligation, as well as the recognition of deferred losses from previous years' lower-than-expected plan asset returns.

Wholesale energy sales and purchase contracts that meet the definition of a derivative are recorded at fair value. For derivative contracts, when forward prices are higher than contract prices, wholesale energy sales contracts will have unrealized losses and wholesale purchase contracts will have unrealized gains. The opposite is true when forward prices are lower than contract prices. Unrealized gains and losses will reverse in future periods when the contracts settle at contract prices. They do not result in cash collections or payments other than in obtaining or providing cash collateral required in support of certain contracts. See "Item 8. Financial Statements – Note 3 – Derivative Instruments" for a summary of unrealized gains and losses on wholesale energy sales and purchase contracts.

Year Ended March 31, 2006 Compared to Year Ended March 31, 2005

Revenues

(Millions of dollars)	Year Ended March 31.		Favorable/(Unfavorable)	
	2006	2005	\$ Change	% Change
Retail	\$ 2,808.6	\$ 2,648.8	\$ 159.8	6.0 %
Wholesale sales and other	1,088.1	400.0	688.1	172.0
Total revenues	<u>\$ 3,896.7</u>	<u>\$ 3,048.8</u>	<u>\$ 847.9</u>	27.8
Retail energy sales (thousands of MWh)	50,112	48,919	1,193	2.4
Total retail customers (in thousands)	1,640	1,605	35	2.2

Retail revenues increased \$159.8 million, or 6.0%, primarily due to:

- \$74.1 million of increases from higher prices approved by regulators;
- \$43.2 million of increases related to growth in the number of residential and commercial customers;
- \$28.7 million of increases due to higher average residential and industrial customer usage, net of decreases in commercial and other customer usage; and
- \$13.8 million of increases due to changes in price mix, resulting from the levels of customer usage at different customer tariffs in the various states that PacifiCorp serves.

Wholesale sales and other revenues increased \$688.1 million, or 172.0%, primarily due to:

- \$554.4 million of increases from higher unrealized gains on short- and long-term energy sales contracts recorded at fair value, primarily due to changes in forward prices;
- \$108.7 million of increases in wholesale electric sales, primarily due to higher prices;
- \$29.2 million of increases resulting from sales of sulfur dioxide emission allowances;
- \$11.0 million of increases in wholesale natural gas sales; and
- \$8.2 million of increases in revenues from the settlement of amounts previously disputed with third parties; partially offset by,
- \$28.2 million of decreases related to non-physically settled system balancing transactions.

Operating Expenses

(Millions of dollars)	Year Ended March 31.		Favorable/(Unfavorable)	
	2006	2005	\$ Change	% Change
Energy costs	\$ 1,545.1	\$ 948.0	\$ (597.1)	(63.0) %
Operations and maintenance	1,014.5	913.1	(101.4)	(11.1)
Depreciation and amortization	448.3	436.9	(11.4)	(2.6)
Taxes, other than income taxes	96.8	94.4	(2.4)	(2.5)
Total operating expenses	<u>\$ 3,104.7</u>	<u>\$ 2,392.4</u>	<u>\$ (712.3)</u>	(29.8)

Energy costs increased \$597.1 million, or 63.0%, primarily due to:

- \$469.5 million of increases from higher unrealized losses on short- and long-term energy purchase contracts recorded at fair value, primarily due to changes in forward prices;
- \$43.5 million of increases related to unfavorable changes in the fair value of streamflow weather derivative contracts resulting primarily from improved streamflow conditions in the current year compared to prior forecasts;
- \$40.7 million of increases in purchased electricity due to higher prices and volumes;
- \$14.8 million of increases related to higher volumes of coal consumed due primarily to an increase in thermal generation;
- \$13.9 million of increases related to higher prices for coal consumed; and
- \$11.2 million of increases related to higher wheeling expenses.

Operations and maintenance expense increased \$101.4 million, or 11.1%, primarily due to:

- \$43.7 million of increases in employee expenses, primarily due to an increase in headcount and higher benefit and pension costs;
- \$17.0 million in employee severance expense incurred during the current year;
- \$11.3 million of increases in materials and supplies utilized in plant overhaul activities;
- \$9.7 million of increases in third-party contract and service fees; and
- \$7.2 million of increases from services rendered by Scottish Power UK plc prior to the sale of PacifiCorp to MEHC, and charged to PacifiCorp pursuant to the affiliated interest cross-charge policy.

Depreciation and amortization expense increased \$11.4 million, or 2.6%, primarily due to:

- \$13.9 million of increases in depreciation expense due to additions to plant in service; partially offset by,
- \$3.0 million of decreases in amortization expense predominantly due to certain capitalized software becoming fully amortized.

Interest and Other (Income) Expense

(Millions of dollars)	Year Ended March 31,		Favorable/(Unfavorable)	
	2006	2005	\$ Change	% Change
Interest expense	\$ 279.9	\$ 267.4	\$ (12.5)	(4.7) %
Interest income	(9.5)	(9.1)	0.4	4.4
Interest capitalized	(32.4)	(14.8)	17.6	118.9
Minority interest and other	(6.1)	(7.3)	(1.2)	(16.4)
Total	<u>\$ 231.9</u>	<u>\$ 236.2</u>	<u>\$ 4.3</u>	1.8

Interest expense increased \$12.5 million, or 4.7%, primarily due to:

- Higher average debt outstanding and higher variable rates during the year ended March 31, 2006; partially offset by,
- Lower average fixed rates on long-term debt during the year ended March 31, 2006.

Interest capitalized increased \$17.6 million, or 118.9%, primarily due to higher average construction work-in-progress balances that qualify for capitalized interest and higher capitalization rates during the year ended March 31, 2006.

Minority interest and other expense changed \$1.2 million, primarily due to lower gains on net investments for the year ended March 31, 2006 compared to the year ended March 31, 2005.

Income Tax Expense

Income tax expense increased \$30.9 million, or 18.3%, primarily due to:

- \$49.0 million of increases due to higher levels of income from continuing operations before income taxes for the year ended March 31, 2006; and

- \$9.7 million of increases in the income tax contingency reserve; partially offset by,
- \$9.2 million of decreases from the tax effect of the regulatory treatment of book and tax depreciation differences of \$3.1 million and of the regulatory treatment of other differences of \$6.1 million;
- \$5.4 million of decreases due to permanent book and tax differences of Internal Revenue Service settlements in the prior year;
- \$5.0 million of decreases from the tax effect of increases in depletion expense; and
- \$4.3 million of decreases from the tax effect of certain state income tax credits.

Year Ended March 31, 2005 Compared to Year Ended March 31, 2004

Revenues

(Millions of dollars)	Year Ended March 31,		Favorable/(Unfavorable)	
	2005	2004	\$ Change	% Change
Retail	\$ 2,648.8	\$ 2,547.0	\$ 101.8	4.0 %
Wholesale sales and other	400.0	647.5	(247.5)	(38.2)
Total revenues	<u>\$ 3,048.8</u>	<u>\$ 3,194.5</u>	<u>\$ (145.7)</u>	<u>(4.6)</u>
Retail energy sales (thousands of MWh)	48,919	48,679	240	0.5
Total retail customers (in thousands)	1,605	1,570	35	2.2

Retail revenues increased \$101.8 million, or 4.0%, primarily due to:

- \$108.9 million of increases from higher prices approved by regulators; and
- \$49.0 million of increases relating to growth in the number of residential, commercial and industrial customers; partially offset by,
- \$39.8 million of decreases from lower average residential customer usage, net of increases in commercial usage; and
- \$7.3 million of decreases due to a change in price mix, which resulted from the levels of customer usage at different customer tariffs in the various states that PacifiCorp serves.

Wholesale sales and other revenues decreased \$247.5 million, or 38.2%, primarily due to:

- \$300.6 million of decreases from higher unrealized losses on short- and long-term energy sales contracts recorded at fair value, primarily due to changes in forward prices; and
- \$48.1 million of decreases related to non-physically settled system balancing transactions; partially offset by,
- \$47.2 million of increases due to higher revenues related to regulatory asset recovery, including \$27.9 million due to a new tariff in Utah;
- \$45.9 million of increases in wholesale electric sales due to higher volumes and prices; and
- \$2.8 million of increases due to higher wheeling revenue.

Operating Expenses

(Millions of dollars)	Year Ended March 31,		Favorable/(Unfavorable)	
	2005	2004	\$ Change	% Change
Energy costs	\$ 948.0	\$ 1,156.7	\$ 208.7	18.0 %
Operations and maintenance	913.1	895.8	(17.3)	(1.9)
Depreciation and amortization	436.9	428.8	(8.1)	(1.9)
Taxes, other than income taxes	94.4	95.3	0.9	0.9
Total operating expenses	<u>\$ 2,392.4</u>	<u>\$ 2,576.6</u>	<u>\$ 184.2</u>	<u>7.1</u>

Energy costs decreased \$208.7 million, or 18.0%, primarily due to:

- \$302.9 million of decreases from higher unrealized gains on short- and long-term energy purchase contracts recorded at fair value, primarily due to changes in forward prices;

- \$27.5 million of decreases due to favorable changes in fair value on streamflow weather derivative contracts; and
- \$9.9 million of decreases due to lower volumes of coal consumed due mainly to a reduction in thermal plant generation; partially offset by,
- \$98.4 million of increases in purchased electricity due to higher volumes and prices; and
- \$30.0 million of increases due to higher prices for coal consumed.

Operations and maintenance expense increased \$17.3 million, or 1.9%, primarily due to:

- \$44.3 million of increases in employee salary expense and other direct employee expenses, primarily due to an increase in headcount and higher benefit and pension costs;
- \$14.9 million of increases from services rendered by Scottish Power UK plc and charged to PacifiCorp pursuant to ScottishPower's affiliated interest cross-charge policy, which became effective April 1, 2004; and
- \$12.1 million of net increases due to changes in regulatory assets and liabilities, including \$27.0 million of increased Utah demand-side management amortization; partially offset by,
- \$26.9 million of decreases in third-party contract and service fees, including a reduction in the use of contractors for certain activities, including information technology, planned outages and field operations;
- \$5.5 million of a decrease due to the recognition of claims in the prior year due to the bankruptcy of an insurance carrier; and
- \$5.5 million of decreases in insurance costs.

Depreciation and amortization expense increased \$8.1 million, or 1.9%, primarily due to:

- \$15.8 million of increases in depreciation and amortization expense due to an increase in plant in service; and
- \$4.6 million of increases in amortization expense due to higher capitalized software balances; partially offset by,
- \$12.9 million of decreases in capitalized software amortization following a change in the estimated useful lives of certain computer software systems.

Interest and Other (Income) Expense

(Millions of dollars)	Year Ended March 31,		Favorable/(Unfavorable)	
	2005	2004	\$ Change	% Change
Interest expense	\$ 267.4	\$ 256.5	\$ (10.9)	(4.2) %
Interest income	(9.1)	(13.8)	(4.7)	(34.1)
Interest capitalized	(14.8)	(19.9)	(5.1)	(25.6)
Minority interest and other	(7.3)	1.6	8.9	556.3
Total	<u>\$ 236.2</u>	<u>\$ 224.4</u>	<u>\$ (11.8)</u>	(5.3)

Interest expense increased \$10.9 million, or 4.2%, primarily due to \$8.9 million of increases resulting from an increase in average amount of debt outstanding, due in part to the refinancing of \$352.0 million of Preferred securities redeemed in August 2003 with long-term debt, partially offset by a decrease in average interest rates.

Interest income decreased \$4.7 million, or 34.1%, primarily due to decreases in interest income on regulatory assets.

Interest capitalized decreased \$5.1 million, or 25.6%, primarily due to lower average capitalization rates applied to higher qualifying construction work-in-progress balances during the year ended March 31, 2005.

Minority interest and other expense changed \$8.9 million, primarily due to:

- \$11.7 million of a decrease in expense relating to distributions on Preferred securities, which were redeemed in August 2003;
- \$2.3 million of a decrease in charitable donations; partially offset by,
- \$4.3 million of an increase in income relating to proceeds from company-owned life insurance.

Income Tax Expense

Income tax expense increased \$24.0 million, or 16.6%, primarily due to:

- \$14.2 million of increases in the federal tax contingency reserve due to \$8.5 million of additional accruals in the current year related to new activities/development of tax examinations, compared to \$5.7 million of contingency reserve releases in the prior year due to the resolution of certain tax examinations;
- \$9.5 million of increases due to higher levels of income from continuing operations before income taxes and cumulative effect of accounting change for the year ended March 31, 2005; and
- \$5.4 million of increases due to permanent book and tax differences of Internal Revenue Service settlements; partially offset by,
- \$3.9 million of decreases from the tax effect of regulatory treatment of book and tax differences; and
- \$3.7 million of decreases in state income tax effect.

LIQUIDITY AND CAPITAL RESOURCES

Sources and Uses of Cash

PacifiCorp depends on both internal and external sources of liquidity to provide working capital and to fund capital requirements. Short-term cash requirements not met by cash provided by operating activities are generally satisfied with proceeds from short-term borrowings. Long-term cash needs are met through sales of securities, including additional long-term debt issuances, and, in the past, also by issuance of common stock to PacifiCorp's former parent company, PHI. PacifiCorp expects it will need additional periodic equity contributions from its existing parent over the next five years. Issuance of longer-term securities is influenced by levels of short-term debt, cash from operations, capital expenditures, market conditions, regulatory approvals and other considerations.

Operating Activities

Net cash flows provided by operating activities increased \$183.5 million to \$894.6 million for the year ended March 31, 2006 compared to \$711.1 million for the year ended March 31, 2005, primarily due to higher retail revenues, increased generation output, reduced net cash collateral requirements and the net impact of the timing of cash collection and payments, partially offset by increases in income tax payments and higher fuel inventory levels.

Net cash provided by operating activities decreased \$120.8 million to \$711.1 million for the year ended March 31, 2005 compared to \$831.9 million for the year ended March 31, 2004, due primarily to increases in net cash collateral requirements; increases in the level of funding for pension and other postretirement benefit plans; higher inventory levels; and the net impact of the timing of cash collection and payments.

Investing Activities

Net cash used in investing activities increased \$177.4 million to \$1,024.1 million for the year ended March 31, 2006, primarily due to higher capital expenditures during the year ended March 31, 2006 compared to the prior year. Capital expenditures totaled \$1,049.0 million for the year ended March 31, 2006, compared to \$851.6 million for the year ended March 31, 2005. The increase was primarily due to \$109.7 million of increased expenditures on the construction of the Lake Side Power Plant, increases in various capital projects related to transmission and distribution and other thermal and hydroelectric facilities and \$58.5 million for the installation of emission control equipment at the Huntington Power Plant, partially offset by \$113.9 million of decreases in expenditures for the Currant Creek Plant. Expenditures for the Lake Side Power Plant will continue to be capitalized as construction work-in-progress until the plant is placed into service, which is expected to occur by May 2007. The Currant Creek Power Plant was completed in simple and combined-cycle phases. The simple-cycle phase was placed into service during May and June 2005 and combined-cycle phase was placed into service during March 2006.

Net cash used in investing activities increased \$143.2 million to \$846.7 million for the year ended March 31, 2005, primarily due to higher capital expenditures during the year ended March 31, 2005 compared to the prior year. Capital expenditures totaled \$851.6 million for the year ended March 31, 2005, compared to \$690.4 million for the year ended March 31, 2004. The increase was primarily due to \$158.9 million of increased expenditures on the

construction of the Currant Creek Power Plant and \$49.6 million for construction of the Lake Side Power Plant, partially offset by lower expenditures on the distribution and transmission upgrades along the Wasatch Front in Utah, as well as reductions in other capital expenditures.

Financing Activities

Short-Term Debt

PacifiCorp's short-term debt decreased by \$284.4 million during the year ended March 31, 2006 to \$184.4 million, primarily due to proceeds from long-term debt and common stock financing during the period, partially offset by capital expenditures in excess of net cash from operations. Regulatory authorities limit PacifiCorp to \$1.5 billion of short-term debt, of which \$184.4 million was outstanding at March 31, 2006, with a weighted-average interest rate of 4.8%.

PacifiCorp's short-term debt increased by \$343.9 million during the year ended March 31, 2005 to \$468.8 million, primarily due to capital expenditures in excess of net cash from operations and pre-funding of maturing long-term debt, partially offset by the proceeds from the long-term debt financing during the period. Short-term debt increased by \$99.9 million during the year ended March 31, 2004, primarily due to changes in working capital, maturing long-term debt, increased capital expenditures and the resumption of paying dividends on common shares.

Revolving Credit Agreement

PacifiCorp's short-term borrowings and certain other financing arrangements are supported by an \$800.0 million committed bank revolving credit agreement, which was amended during August 2005. Changes included an increase to 65.0% in the covenant not to exceed a specified debt-to-capitalization percentage, extension of the termination date to August 2010 and exclusion of the acquisition of PacifiCorp by MEHC as an event of default under the agreement. The interest rate on advances under this facility is generally based on the London Interbank Offered Rate (LIBOR) plus a margin that varies based on PacifiCorp's credit ratings. As of March 31, 2006, this facility was fully available and there were no borrowings outstanding. In addition to this committed credit facility, at March 31, 2006, PacifiCorp had \$79.6 million in money market accounts included in Cash and cash equivalents available to meet its liquidity needs.

PacifiCorp's revolving credit agreement contains customary covenants and default provisions, which PacifiCorp monitors on a regular basis. As of March 31, 2006, PacifiCorp was in compliance with the covenants of its revolving credit agreement, which also apply to its letters of credit. See "Future Uses of Cash - Contractual Obligations and Commercial Commitments - Commercial Commitments" below for information regarding PacifiCorp's letters of credit.

Long-Term Debt

During the year ended March 31, 2006, PacifiCorp made scheduled long-term debt repayments of \$269.7 million.

In June 2005, PacifiCorp issued \$300.0 million of its 5.25% Series of First Mortgage Bonds due June 15, 2035. PacifiCorp used the proceeds for the reduction of short-term debt, including the short-term debt used in December 2004 to redeem its 8.625% Series of First Mortgage Bonds due December 13, 2024 totaling \$20.0 million.

During the year ended March 31, 2005, PacifiCorp made scheduled long-term debt repayments of \$239.8 million. Additionally, during December 2004, PacifiCorp redeemed, prior to maturity, all of the 8.625% First Mortgage Bonds due December 13, 2024 totaling \$20.0 million.

In March 2005, the maturity dates for three series of variable-rate pollution-control revenue bonds totaling \$38.1 million were extended to December 1, 2020.

In August 2004, PacifiCorp issued \$200.0 million of its 4.95% Series of First Mortgage Bonds due August 15, 2014 and \$200.0 million of its 5.90% Series of First Mortgage Bonds due August 15, 2034. PacifiCorp used the proceeds for general corporate purposes, including the reduction of short-term debt.

For the year ended March 31, 2004, PacifiCorp made scheduled long-term debt repayments of \$136.6 million. Additionally, during July and August 2003, PacifiCorp redeemed, prior to maturity, First Mortgage Bonds totaling

\$57.5 million and Preferred Securities totaling \$352.0 million. These retirements were funded initially with short-term debt. In September 2003, PacifiCorp issued \$200.0 million of its 4.30% First Mortgage Bonds due September 15, 2008 and \$200.0 million of its 5.45% First Mortgage Bonds due September 15, 2013.

PacifiCorp's Mortgage and Deed of Trust creates a lien on most of PacifiCorp's electric utility property, allowing the issuance of bonds based on:

- A percentage of utility property additions;
- Bond credits arising from retirement of previously outstanding bonds; and/or
- Deposits of cash.

The amount of bonds that PacifiCorp may issue generally is also subject to a net earnings test. As of March 31, 2006, PacifiCorp estimated it would be able to issue up to \$4.7 billion of new First Mortgage Bonds under the most restrictive issuance test in the mortgage. Any issuances would be subject to market conditions and amounts may be further limited by regulatory authorizations or commitments or by covenants and tests contained in other financing agreements. PacifiCorp also has the ability to release property from the lien of the Mortgage on the basis of property additions, bond credits and/or deposits of cash. See also "Limitations" below.

During September 2005, the SEC declared effective PacifiCorp's shelf registration statement covering \$700.0 million of future first mortgage bond and unsecured debt issuances. PacifiCorp has not yet issued any of the securities covered by this registration statement.

PacifiCorp has state regulatory authority to issue up to an additional \$700.0 million of long-term debt from the UPSC, OPUC and IPUC and up to \$100.0 million of first mortgage bonds from the WUTC. An additional filing will be made with the WUTC prior to any future issuances.

Common Stock

During the year ended March 31, 2006, PacifiCorp issued 44,884,826 shares of its common stock to PHI, its former parent company, at a total price of \$484.7 million. PacifiCorp used the proceeds from the sale of these shares for the reduction of short-term debt.

PacifiCorp expects to seek amendments to existing state regulatory authority or new authorizations that would permit the issuance of its common stock to PPW Holdings LLC.

Preferred Stock Redemptions

PacifiCorp redeemed \$7.5 million of Preferred stock subject to mandatory and optional redemption during each of the years ended March 31, 2006, 2005 and 2004.

Dividends

During the year ended March 31, 2006, PacifiCorp had the following dividend activity:

- \$175.0 million declared and paid on common stock;
- \$5.6 million declared on preferred stock and preferred stock subject to mandatory redemption, of which \$3.5 million was recorded as interest expense; and
- \$5.8 million paid on preferred stock and preferred stock subject to mandatory redemption.

On March 20, 2006, immediately prior to the closing of PacifiCorp's sale to MEHC, PacifiCorp paid a dividend on common stock, at that time held by PHI, in the aggregate amount of \$16.8 million. The dividend was reduced pursuant to Amendment No. 1 to the Stock Purchase Agreement among MEHC, ScottishPower and PHI executed on the date of the transaction's closing from the \$56.6 million aggregate amount originally declared by the PacifiCorp Board of Directors on January 27, 2006.

During the year ended March 31, 2005, PacifiCorp had the following dividend activity:

- \$193.3 million declared and paid on common stock;
- \$6.1 million declared on preferred stock and preferred stock subject to mandatory redemption, of which \$4.0

- million was recorded as interest expense; and
- \$6.2 million paid on preferred stock and preferred stock subject to mandatory redemption.

During the year ended March 31, 2004, PacifiCorp had the following dividend activity:

- \$160.6 million declared and paid on common stock;
- \$6.7 million declared on preferred stock and preferred stock subject to mandatory redemption, of which \$3.4 million was recorded as interest expense; and
- \$6.8 million paid on preferred stock and preferred stock subject to mandatory redemption.

Capitalization

(Millions of dollars)	March 31,			
	2006		2005	
Short-term debt	\$ 184.4	2.2 %	\$ 468.8	6.0 %
Long-term debt, including current maturities	3,937.9	47.9	3,898.9	50.0
Preferred stock subject to mandatory redemption	45.0	0.5	52.5	0.7
Preferred stock	41.3	0.5	41.3	0.5
Common equity	4,010.5	48.9	3,335.8	42.8
Total capitalization	<u>\$ 8,219.1</u>	<u>100.0 %</u>	<u>\$ 7,797.3</u>	<u>100.0 %</u>

PacifiCorp manages its capitalization and liquidity position with a key objective of retaining existing credit ratings, which is expected to facilitate continuing access to flexible borrowing arrangements at favorable costs and rates. This objective, subject to periodic review and revision, attempts to balance the interests of all shareholders, ratepayers and creditors and to provide a competitive cost of capital and predictable capital market access.

As a result of recent changes in accounting standards, such as FIN 46R, *Consolidation of Variable-Interest Entities*, an interpretation of Accounting Research Bulletin No. 51, and EITF No. 01-08, *Determining Whether an Arrangement Is a Lease*, it is possible that new purchase power and gas agreements, transmission arrangements or amendments to existing arrangements may be accounted for as capital lease obligations or debt on PacifiCorp's financial statements. While PacifiCorp has successfully amended covenants in financing arrangements that may be impacted by these changes, it may be more difficult for PacifiCorp to comply with its capitalization targets or regulatory commitments concerning minimum levels of common equity as a percentage of capitalization. This may lead PacifiCorp to seek amendments or waivers from regulators, delay or reduce dividends or spending programs, seek additional new common equity contributions from its immediate parent, PPW Holdings LLC, or take other actions.

Limitations

In addition to PacifiCorp's capital structure objectives, its debt capacity is also governed by its contractual and regulatory commitments.

PacifiCorp's credit agreement contains customary covenants and default provisions, including a covenant not to exceed a specified debt-to-capitalization ratio of 65.0%. As of March 31, 2006, management believes that PacifiCorp could have borrowed an additional \$3.3 billion without exceeding this threshold. Any additional borrowings would be subject to market conditions, and amounts may be further limited by regulatory authorizations or by covenants and tests contained in other financing agreements.

The state regulatory orders that authorized the acquisition by MEHC contain restrictions on PacifiCorp's ability to pay common dividends to the extent that they would reduce PacifiCorp's common stock equity below specified percentages of defined capitalization.

As of March 31, 2006, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to PPW Holdings LLC or MEHC without prior state regulatory approval to the extent that it would reduce PacifiCorp's common stock equity below 48.25% of its total capitalization, excluding short-term debt and current maturities of long-term debt. After December 31, 2008, this minimum level of common equity declines annually to

44.0% after December 31, 2011. The terms of this commitment treat 50.0% of PacifiCorp's preferred stock outstanding prior to the acquisition of PacifiCorp by MEHC as common equity. As of March 31, 2006, PacifiCorp's actual common stock equity percentage, as calculated under this measure, exceeded the minimum threshold.

FUTURE USES OF CASH

Dividends

PacifiCorp does not presently anticipate that it will declare dividends on common stock during the 12 months ending March 31, 2007.

Capital Expenditure Program

Actual capital expenditures were \$1,049.0 million for the year ended March 31, 2006 and \$851.6 million for the year ended March 31, 2005. Estimated capital expenditures for the 12 months ending March 31, 2007 are expected to be approximately \$1.1 billion, which include \$129.2 million for emissions control equipment to address current and anticipated air quality regulations, \$137.9 million for generation development projects, and \$875.1 million for ongoing operational projects.

In conjunction with state regulatory approvals of the PacifiCorp acquisition, MEHC and PacifiCorp committed to invest \$812.0 million in capital spending for emission control equipment to address current and future air quality initiatives implemented by the EPA or by the states in which PacifiCorp operates facilities. Additional capital expenditures for emission reduction projects may be required, depending on the outcome of pending or new air quality regulations. The actual and estimated expenditures for emissions control equipment include amounts for installation of equipment at the Huntington Power Plant. The actual expenditures for the Huntington Power Plant were \$59.6 million for the year ended March 31, 2006. The estimated expenditures for the 12 months ending March 31, 2007 are \$68.7 million.

In March 2006, PacifiCorp completed construction of the Currant Creek Power Plant, a 523.0-MW combined-cycle plant in Utah. Total project costs incurred through March 31, 2006 were approximately \$338.0 million. The estimates provided above for generation development projects include the remaining costs to have the Lake Side Power Plant constructed, as well as upgrades of other generation plant equipment. As of March 31, 2006, \$208.9 million of the \$347.0 million expected total cost for the Lake Side Power Plant had been incurred.

PacifiCorp is focused on infrastructure improvement projects in targeted areas to improve customer service and network safety and enhance system reliability and performance. PacifiCorp and MEHC have committed to a number of transmission and distribution system investments in connection with regulatory approval of PacifiCorp's sale to MEHC. Approximately \$519.5 million in investments in PacifiCorp's transmission and distribution system are expected over the next several years, of which \$13.9 million are currently estimated to be incurred during the 12 months ending March 31, 2007.

All of these expenditures are subject to continuing review and revision by PacifiCorp, and actual costs could vary from estimates due to various factors, such as changes in business conditions, revised load-growth estimates, future legislative and regulatory developments, increasing costs in labor, equipment and materials, competition in the industry for similar technology and management's strategies for achieving compliance with regulations. The estimates of capital expenditures for the 12 months ending March 31, 2007 generally excludes the potential impact on generation and transmission capacity of future decisions arising from further stages of PacifiCorp's various Integrated Resource Plans. Additional expenditures may be significant but are spread over a number of years and cannot be accurately estimated at this time. Based on future decisions arising from the Integrated Resource Plan process, including wind generation projects, the estimate of capital expenditures may be revised.

In funding its capital expenditure program, PacifiCorp expects to obtain funds required for construction and other purposes from sources similar to those used in the past, including operating cash flows, the issuance of new long-term and short-term debt and equity contributions from MEHC.

Contractual Obligations and Commercial Commitments

Contractual Obligations

The table below shows PacifiCorp's contractual obligations as of March 31, 2006.

(Millions of dollars)	Payments due during the 12 months ending March 31,				
	2007	2008-2009	2010-2011	Thereafter	Total
Long-term debt, including interest:					
Fixed-rate obligations	\$ 429.8	\$ 911.7	\$ 479.9	\$ 4,223.0	\$ 6,044.4
Variable-rate obligations (a)	17.4	34.8	34.8	690.9	777.9
Short-term debt, including interest	185.0	-	-	-	185.0
Preferred stock subject to mandatory redemption	3.7	41.3	-	-	45.0
Capital leases, including interest	4.8	9.6	9.9	63.8	88.1
Operating leases (b)	15.0	18.2	4.2	8.8	46.2
Asset retirement obligations (c)	7.0	34.0	35.8	356.7	433.5
Power purchase agreements: (d)					
Electricity commodity contracts	603.2	380.5	211.4	667.2	1,862.3
Electricity capacity contracts	136.9	299.6	310.4	1,301.1	2,048.0
Electricity mixed contracts	16.2	30.7	26.8	178.4	252.1
Transmission	45.7	77.2	72.1	503.3	698.3
Fuel purchase agreements: (d)					
Natural gas supply and transportation	317.4	678.8	433.8	869.3	2,299.3
Coal supply and transportation	199.4	444.2	358.7	1,062.2	2,064.5
Purchase obligations (e)	123.2	42.0	2.2	3.1	170.5
Owned hydroelectric commitments (f)	28.8	71.7	66.7	469.9	637.1
Other long-term liabilities (g)	5.0	6.0	2.3	7.3	20.6
Total contractual cash obligations	<u>\$ 2,138.5</u>	<u>\$ 3,080.3</u>	<u>\$ 2,049.0</u>	<u>\$ 10,405.0</u>	<u>\$ 17,672.8</u>

- (a) Consists of principal and interest for pollution-control revenue bond obligations with interest rates scheduled to reset within the next 12 months. Future variable interest rates are set at March 31, 2006 rates. See "Item 7A. Interest Rate Risk" for additional discussion related to variable-rate liabilities.
- (b) Excluded from these amounts are power purchase agreements that meet the definition of an operating lease. Such amounts are included with power purchase agreements.
- (c) Represents expected cash payments adjusted for inflation for estimated costs to perform legally required asset retirement activities.
- (d) Commodity contracts are agreements for the delivery of energy. Capacity contracts are agreements that provide rights to the energy output of a specified facility. Forecasted or other applicable estimated prices were used to determine total dollar value of the commitments for purposes of the table. Amounts included in power purchase agreements include those agreements that meet the definition of an operating lease.
- (e) Includes minimum commitments for maintenance, outsourcing of certain services, contracts for software, telephone, data and consulting or advisory services. Also includes contractual obligations for engineering, procurement and construction costs on the Lake Side Power Plant and Huntington Power Plant emission control equipment.
- The purchase obligation amounts consist of items for which PacifiCorp is contractually obligated to purchase from a third party as of March 31, 2006. These amounts only constitute the known portion of PacifiCorp's expected future expenses; therefore, the amounts presented in the table will not provide a reliable indicator of PacifiCorp's expected future cash outflows on a stand-alone basis. For purposes of identifying and accumulating purchase obligations, PacifiCorp has included all contracts meeting the definition of a purchase obligation (e.g., legally binding and specifying all significant terms, including fixed or minimum amount or quantity to be purchased and the approximate timing of the transaction). For those contracts involving a fixed or minimum quantity but variable pricing, PacifiCorp has estimated the contractual obligation based on its best estimate of pricing that will be in effect at the time the obligation is incurred.
- (f) PacifiCorp has entered into settlement agreements with various interested parties to resolve issues necessary to

obtain new hydroelectric licenses from the FERC. These settlement agreements generally include clauses that allow for termination of certain of PacifiCorp's obligations if the FERC license order is not consistent with the settlement agreement. The table only includes contractual obligations made in settlement agreements that are not contingent upon the FERC license being consistent with the settlement agreement and obligations that are required by the FERC licenses. Hydroelectric licenses have varying expiration dates, and several expire within the next five years. The contractual obligations included in the table expire with the license expiration dates. However, PacifiCorp plans to acquire new licenses that will allow for continued operation for more than 30 years and expects contractual obligations to continue or increase.

- (g) Includes environmental commitments recorded on the balance sheet that are contractually or legally binding. Excludes regulatory liabilities and employee benefit plan obligations that are not legally or contractually fixed as to timing and amount. Deferred income taxes are also excluded since cash payments are based primarily on taxable income for each discrete year.

Commercial Commitments

At March 31, 2006, PacifiCorp had \$517.8 million of standby letters of credit and standby bond purchase agreements available to provide credit enhancement and liquidity support for variable-rate pollution-control revenue bond obligations. In addition, PacifiCorp had approximately \$40.5 million of standby letters of credit to provide credit support for certain transactions as requested by third parties. These committed bank arrangements were all fully available as of March 31, 2006 and expire periodically through the 12 months ending March 31, 2011.

PacifiCorp's standby letters of credit and standby bond purchase agreements generally contain similar covenants to those contained in PacifiCorp's revolving credit agreement. See "Financing Activities – Revolving Credit Agreement" for further information. However, the maximum debt-to-capitalization ratio for one of these arrangements was 60.0% as of March 31, 2006 and was amended in May 2006 to now permit a maximum ratio of 65.0%. PacifiCorp monitors these covenants on a regular basis and at March 31, 2006, was in compliance with the covenants of these agreements.

PacifiCorp's commercial commitments include surety bonds that provide indemnities for PacifiCorp in relation to various commitments it has to third parties for obligations in the event of default on behalf of PacifiCorp. The majority of these bonds are continuous in nature and renew annually. Based on current contractual commitments, PacifiCorp's level of surety bonding beyond the year ended March 31, 2006, is estimated to be approximately \$27.3 million. This estimate is based on current information and actual amounts may vary due to rate changes or changes to the general operations of PacifiCorp.

CREDIT RATINGS

PacifiCorp's credit ratings at March 31, 2006, were as follows:

	<u>Moody's</u>	<u>Standard & Poor's</u>
Issuer/Corporate	Baa1	A-
Senior secured debt	A3	A-
Senior unsecured debt	Baa1	BBB+
Preferred stock	Baa3	BBB
Commercial paper	P-2	A-1
Outlook	Stable	Stable

In February 2006, Moody's Investors Service affirmed the issuer and securities ratings of PacifiCorp and changed the ratings outlook to stable from developing. In March 2006, Standard & Poor's Rating Services affirmed the corporate credit ratings and securities ratings of PacifiCorp and changed the ratings outlook to stable from CreditWatch with negative implications. Also in March 2006, Standard & Poor's Rating Services raised the short-term rating for PacifiCorp to A-1 from A-2.

PacifiCorp has no rating-downgrade triggers that would accelerate the maturity dates of its debt. A change in ratings is not an event of default, nor is the maintenance of a specific minimum level of credit rating a condition to drawing upon PacifiCorp's credit agreement. However, interest rates on loans under the revolving credit agreement and

commitment fees are tied to credit ratings and would increase or decrease when ratings are changed. A ratings downgrade may reduce the accessibility and increase the cost of PacifiCorp's commercial paper program, its principal source of short-term borrowing, and may result in the requirement that PacifiCorp post collateral under certain of PacifiCorp's power purchase and other agreements. Certain authorizations or exemptions by regulatory commissions for the issuance of securities are valid as long as PacifiCorp maintains investment-grade ratings on senior secured debt. A downgrade below that level would necessitate new regulatory applications and approvals.

In conjunction with its risk management activities, PacifiCorp must meet credit quality standards as required by counterparties. In accordance with industry practice, contractual agreements that govern PacifiCorp's energy management activities either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed certain ratings-dependent threshold levels or provide the right for counterparties to demand "adequate assurances" in the event of a material adverse change in PacifiCorp's creditworthiness. If one or more of PacifiCorp's credit ratings decline below investment grade, PacifiCorp would be required to post cash collateral, letters of credit or other similar credit support to facilitate ongoing wholesale energy management activities. As of March 31, 2006, PacifiCorp's credit ratings from Standard & Poor's and Moody's were investment grade; however, if the ratings fell more than one rating below investment grade, PacifiCorp's estimated potential collateral requirements totaled approximately \$334.0 million. PacifiCorp's potential collateral requirements could fluctuate considerably due to seasonality, market prices and their volatility, a loss of key PacifiCorp generating facilities or other related factors.

OFF-BALANCE SHEET ARRANGEMENTS

PacifiCorp from time to time enters into arrangements in the normal course of business to facilitate commercial transactions with third parties that involve guarantee, indemnification or similar arrangements. PacifiCorp currently has indemnification obligations for breaches of warranties or covenants in connection with the sale of certain assets. In addition, PacifiCorp evaluates potential obligations that arise out of variable interests in unconsolidated entities, determined in accordance with the FASB Interpretation No. 46, *Consolidation of Variable-Interest Entities, an interpretation of Accounting Research Bulletin No. 51*. PacifiCorp believes that the likelihood that it would be required to perform or otherwise incur any significant losses associated with any of these obligations is remote. See "Item 8. Financial Statements and Supplementary Data – Note 11 – Guarantees and Other Commitments" and "Note 13 – Consolidation of Variable-Interest Entities" for more information on these obligations and arrangements.

INFLATION

PacifiCorp is subject to rate-of-return regulation and the impact of inflation on the level of cost recovery under regulation varies by state depending upon the type of test-period convention used in the state. In PacifiCorp's state jurisdictions, a 12-month period of historical costs is typically used as the basis for developing a "test year," which may also include various adjustments to eliminate abnormal or one time events, normalize cost levels, or escalate the historical costs to a future level when the new rates will actually be in effect. To the extent that the levels of costs beyond the historical 12-month period can be established either through known adjustments or through the escalation of cost levels in establishing prices, PacifiCorp can mitigate the impacts of inflationary pressures. The majority of PacifiCorp's retail customer prices are established using forecasts. These forecasts may include, but are not limited to, projected rate base levels and expenses, which are adjusted for both inflation and known and measurable changes. They may also include projected revenue and power cost changes related to load growth.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

PacifiCorp participates in a wholesale energy market that includes public utility companies, electricity and natural gas marketers, financial institutions, industrial companies and government entities. A variety of products exist in this market, ranging from electricity and natural gas purchases and sales for physical delivery to financial instruments such as futures, swaps, options and other complex derivatives. Transactions may be conducted directly with customers and suppliers, through brokers, or with an exchange that serves as a central clearing mechanism.

PacifiCorp is subject to the various risks inherent in the energy business, including credit risk, interest rate risk and commodity price risk.

Risk Management

PacifiCorp has a risk management committee that is responsible for the oversight of market and credit risk relating to the commodity transactions of PacifiCorp. To limit PacifiCorp's exposure to market and credit risk, the risk management committee sets policies and limits and approves commodity strategies, which are reviewed frequently to respond to changing market conditions.

Risk is an inherent part of PacifiCorp's business and activities. The risk management process established by PacifiCorp is designed to identify, assess, monitor, report, manage and mitigate each of the various types of risk involved in its business and activities and to measure quantitative market risk exposure and identify qualitative market risk exposure in its businesses. To assist in managing the volatility relating to these exposures, PacifiCorp enters into various transactions, including derivative transactions, consistent with PacifiCorp's risk management policy and procedures. The risk management policy governs energy transactions and is designed for hedging PacifiCorp's existing energy and asset exposures, and to a limited extent, the policy permits arbitrage activities to take advantage of market inefficiencies. The policy and procedures also govern PacifiCorp's use of derivative instruments for commodity derivative transactions, as well as its energy purchase and sales practices, and describe PacifiCorp's credit policy and management information systems required to effectively monitor such derivative use. PacifiCorp's risk management policy provides for the use of only those instruments that have a similar volume or price relationship to its portfolio of assets, liabilities or anticipated transactions, thereby ensuring that such instruments will be primarily used for hedging. PacifiCorp's portfolio of energy derivatives is substantially used for non-trading purposes.

PacifiCorp continues to actively manage its exposure to commodity price volatility. These activities may include adding to the generation portfolio and entering into transactions that help to shape PacifiCorp's system resource portfolio, including wholesale contracts and financially settled temperature-related derivative instruments that reduce volume and price risk due to weather extremes.

Credit Risk

Credit risk relates to the risk of loss that might occur as a result of non-performance by counterparties of their contractual obligations to make or take delivery of electricity, natural gas or other commodities and to make financial settlements of these obligations. Credit risk may be concentrated to the extent that one or more groups of counterparties have similar economic, industry or other characteristics that would cause their ability to meet contractual obligations to be similarly affected by changes in market or other conditions. In addition, credit risk includes not only the risk that a counterparty may default due to circumstances relating directly to it, but also the risk that a counterparty may default due to circumstances involving other market participants that have a direct or indirect relationship with such counterparty.

PacifiCorp seeks to mitigate credit risk (and concentrations of credit risk) by applying specific eligibility criteria to prospective counterparties. However, despite mitigation efforts, defaults by counterparties occur from time to time. PacifiCorp continues to actively monitor the creditworthiness of counterparties with whom it transacts and uses a variety of risk mitigation techniques to limit its exposure as it believes appropriate. When PacifiCorp considers a new asset purchase, transaction or contractual arrangement, market liquidity and the ability to optimize the

investment are main considerations. To mitigate exposure to the financial risks of wholesale counterparties, PacifiCorp has entered into netting and collateral arrangements that include margining and cross-product netting agreements and obtaining third-party guarantees, letters of credit and cash deposits. Counterparties may be assessed interest fees for delayed receipts. If required, PacifiCorp exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

The following table represents PacifiCorp's March 31, 2006 distribution of unsecured credit exposure, net of collateral, within its electricity and natural gas portfolio of purchase and sale contracts and takes into account contractual netting rights.

<u>Distribution of Credit Exposure</u>	<u>% of Total</u>
Investment grade - Externally rated	81.6 %
Non-investment grade - Externally rated	0.1
Investment grade - Internally rated	0.2
Non-investment grade - Internally rated	18.1
	<u>100.0 %</u>

"Externally rated" represents enterprise relationships that have published ratings from at least one major credit rating agency. "Internally rated" represents those relationships that have no rating by a major credit rating agency. For those relationships, PacifiCorp utilizes internally developed, commercially appropriate rating methodologies and credit scoring models to develop a public rating equivalent.

The "Non-investment grade – Internally rated" component of PacifiCorp's overall credit exposure reflects the market value of a small number of contracts that support PacifiCorp's Integrated Resource Plan and Oregon's electric energy restructuring legislation as it relates to renewable energy projects, as well as compliance with FERC regulations requiring utilities to purchase power from qualifying facilities.

Interest Rate Risk

PacifiCorp is exposed to risk resulting from changes in interest rates as a result of its issuance of variable-rate debt and commercial paper. PacifiCorp manages its interest rate exposure by maintaining a blend of fixed-rate and variable-rate debt and by monitoring the effects of market changes in interest rates. Changing interest rates will affect interest paid on variable-rate debt and interest earned by PacifiCorp's pension plan assets, mining reclamation trust funds and cash balances. PacifiCorp's principal sources of variable-rate debt are commercial paper and pollution-control revenue bonds remarketed on a periodic basis. Commercial paper is periodically refinanced with fixed-rate debt when needed and when interest rates are considered favorable. PacifiCorp may also enter into financial derivative instruments, including interest rate swaps, swaptions and United States Treasury lock agreements, to manage and mitigate interest rate exposure. PacifiCorp does not anticipate using financial derivatives as the principal means of managing interest rate exposure. PacifiCorp's weighted-average cost of debt is recoverable in rates. Increases or decreases in interest rates are reflected in PacifiCorp's cost of debt calculation as rate cases are filed. Any adverse change to PacifiCorp's credit rating could negatively impact PacifiCorp's ability to borrow and the interest rates that are charged.

As of March 31, 2006, PacifiCorp had fixed-rate long-term liabilities of \$3,405.4 million in aggregate principal amount and having a fair value of \$3,597.1 million. These instruments have fixed interest rates and therefore do not expose PacifiCorp to the risk of earnings loss due to changes in market interest rates. However, the fair value of these instruments would decrease by approximately \$114.3 million if interest rates were to increase by 10.0% from their levels at March 31, 2006. In general, such a decrease in fair value would impact earnings and cash flows only if PacifiCorp were to reacquire all or a portion of these instruments prior to their maturity.

As of March 31, 2006, PacifiCorp had \$726.1 million of variable-rate liabilities and \$113.6 million of temporary cash investments compared to \$1,010.5 million of variable-rate liabilities and \$182.2 million of temporary cash investments at March 31, 2005. At March 31, 2006 and 2005, PacifiCorp had no financial derivatives in effect relating to interest rate exposure.

Based on a sensitivity analysis as of March 31, 2006, for a one-year horizon, PacifiCorp estimates that if market interest rates average 1.0% higher (lower) during the 12 months ending March 31, 2007 than during the year ended March 31, 2006, interest expense, net of offsetting impacts on interest income, would increase (decrease) by \$6.1 million. Comparatively, based on a sensitivity analysis as of March 31, 2005, for a one-year horizon, had interest rates averaged 1.0% higher (lower) during the year ended March 31, 2006 than during the year ended March 31, 2005, PacifiCorp estimated that interest expense, net of offsetting impacts in interest income, would have increased (decreased) by \$8.3 million. These amounts include the effect of invested cash and were determined by considering the impact of the hypothetical interest rates on the variable-rate securities outstanding as of March 31, 2006 and 2005. The decrease in interest rate sensitivity is primarily due to the decrease in outstanding variable-rate commercial paper, partially offset by the decrease in invested cash. If interest rates change significantly, PacifiCorp might take actions to manage its exposure to the change. However, due to the uncertainty of the specific actions that might be taken and their possible effects, the sensitivity analysis assumes no changes in PacifiCorp's financial structure.

Commodity Price Risk

PacifiCorp's exposure to market risk due to commodity price change is primarily related to its fuel and electricity commodities, which are subject to fluctuations due to unpredictable factors, such as weather, electricity demand and plant performance, that affect energy supply and demand. PacifiCorp's energy purchase and sales activities are governed by PacifiCorp's risk management policy and the risk levels established as part of that policy.

PacifiCorp's energy commodity price exposure arises primarily from its electric supply obligation in the western United States. PacifiCorp manages this risk principally through the operation of its generation plants with a net capability of 8,470.4 MW, as well as transmission rights held both on some of its own 15,580-mile transmission system and on third-party transmission systems, and through its wholesale energy purchase and sales activities. Wholesale contracts are utilized primarily to balance PacifiCorp's physical excess or shortage of net electricity for future time periods. Financially settled contracts are utilized to further mitigate commodity price risk. PacifiCorp may from time to time enter into other financially settled, temperature-related derivative instruments that reduce volume and price risk on days with weather extremes. In addition, a financially settled hydroelectric streamflow hedge is in place through September 2006 to reduce volume and price risks associated with PacifiCorp's hydroelectric generation resources.

PacifiCorp measures the market risk in its electricity and natural gas portfolio daily, utilizing a historical Value-at-Risk ("VaR") approach and other measurements of net position. PacifiCorp also monitors its portfolio exposure to market risk in comparison to established thresholds and measures its open positions subject to price risk in terms of quantity at each delivery location for each forward time period.

VaR computations for the electricity and natural gas commodity portfolio are based on a historical simulation technique, utilizing historical price changes over a specified (holding) period to simulate potential forward energy market price curve movements to estimate the potential unfavorable impact of such price changes on the portfolio positions scheduled to settle within the following 24 months. The quantification of market risk using VaR provides a consistent measure of risk across PacifiCorp's continually changing portfolio. VaR represents an estimate of possible changes at a given level of confidence in fair value that would be measured on its portfolio assuming hypothetical movements in future market rates and is not necessarily indicative of actual results that may occur.

PacifiCorp's VaR computations for its electricity and natural gas commodity portfolio utilize several key assumptions, including a 99.0% confidence level for the resultant price changes and a holding period of five business days. The calculation includes short-term derivative commodity instruments held for risk mitigation and balancing purposes, the expected resource and demand obligations from PacifiCorp's long-term contracts, the expected generation levels from PacifiCorp's generation assets and the expected retail and wholesale load levels. The portfolio reflects flexibility contained in contracts and assets, which accommodate the normal variability in PacifiCorp's demand obligations and generation availability. These contracts and assets are valued to reflect the variability PacifiCorp experiences as a load-serving entity. Contracts or assets that contain flexible elements are often referred to as having embedded options or option characteristics. These options provide for energy volume changes that are sensitive to market price changes. Therefore, changes in the option values affect the energy position of the portfolio

with respect to market prices, and this effect is calculated daily. When measuring portfolio exposure through VaR, these position changes that result from the option sensitivity are held constant through the historical simulation to avoid understating VaR.

As of March 31, 2006, PacifiCorp's estimated potential five-day unfavorable impact on fair value of the electricity and natural gas commodity portfolio over the next 24 months was \$22.4 million, as measured by the VaR computations described above, compared to \$15.5 million as of March 31, 2005. The minimum, average and maximum daily VaR (five-day holding periods) for the years ended March 31, 2006 and 2005 are as follows:

(Millions of dollars)	2006		2005	
Minimum VaR (measured)	\$	6.7	\$	10.6
Average VaR (calculated)		16.9		16.6
Maximum VaR (measured)		46.2		26.3

PacifiCorp maintained compliance with its VaR limit procedures during the year ended March 31, 2006. Changes in markets inconsistent with historical trends or assumptions used could cause actual results to exceed predicted limits.

Fair Value of Derivatives

The following table shows the changes in the fair value of energy-related contracts subject to the requirements of SFAS No. 133 from April 1, 2005, to March 31, 2006 and quantifies the reasons for the changes.

(Millions of dollars)	Net Asset (Liability)		Regulatory Net Asset (Liability) (b)
	Trading	Non-trading	
Fair value of contracts outstanding at March 31, 2005	\$ 0.2	\$ (154.4)	\$ 170.0
Contracts realized or otherwise settled during the period	(0.2)	(115.8)	128.3
Other changes in fair values (a)	0.2	277.9	(203.6)
Fair value of contracts outstanding at March 31, 2006	<u>\$ 0.2</u>	<u>\$ 7.7</u>	<u>\$ 94.7</u>

- (a) Other changes in fair values include the effects of changes in market prices, inflation rates and interest rates, including those based on models, on new and existing contracts.
- (b) Net unrealized losses (gains) related to derivative contracts included in rates are recorded as a regulatory net asset (liability).

The fair value of derivative instruments is determined using forward price curves. Forward price curves represent PacifiCorp's estimates of the prices at which a buyer or seller could contract today for delivery or settlement of a commodity at future dates. PacifiCorp bases its forward price curves upon market price quotations when available and internally developed and commercial models with internal and external fundamental data inputs when market quotations are unavailable. In general, PacifiCorp estimates the fair value of a contract by calculating the present value of the difference between the prices in the contract and the applicable forward price curve. Price quotations for certain major electricity trading hubs are generally readily obtainable for the first six years, and therefore PacifiCorp's forward price curves for those locations and periods reflect observable market quotes. However, in the later years or for locations that are not actively traded, PacifiCorp must develop forward price curves. For short-term contracts at less actively traded locations, prices are modeled based on observed historical price relationships with actively traded locations. For long-term contracts extending beyond six years, the forward price curve is based upon the use of a fundamentals model (cost-to-build approach) due to the limited information available. Factors used in the fundamentals model include the forward prices for the commodities used as fuel to generate electricity, the expected system heat rate (which measures the efficiency of electricity plants in converting fuel to electricity) in the region where the purchase or sale takes place and a fundamental forecast of expected spot prices based on modeled supply and demand in the region. The assumptions in these models are critical since any changes to the assumptions

could have a significant impact on the fair value of the contract. Contracts with explicit or embedded optionality are valued by separating each contract into its physical and financial forward and option components. Forward components are valued against the appropriate forward price curve. The optionality is valued using a modified Black-Scholes model or a stochastic simulation (Monte Carlo) approach. Each option component is modeled and valued separately using the appropriate forward price curve.

PacifiCorp's valuation models and assumptions are continuously updated to reflect current market information, and evaluations and refinements of model assumptions are performed on a periodic basis.

The following table shows summarized information with respect to valuation techniques and contractual maturities of PacifiCorp's energy-related contracts qualifying as derivatives under SFAS No. 133 as of March 31, 2006.

(Millions of dollars)	Fair Value of Contracts at Period-End				
	Maturity Less Than 1 Year	Maturity 1-3 Years	Maturity 4-5 Years	Maturity in Excess of 5 Years	Total Fair Value
Trading:					
Values based on quoted market prices from third-party sources	\$ 0.2	\$ -	\$ -	\$ -	\$ 0.2
Non-trading:					
Values based on quoted market prices from third-party sources	\$ 58.7	\$ 49.7	\$ 6.0	\$ 1.2	\$ 115.6
Values based on models and other valuation methods	64.9	82.9	4.9	(260.6)	(107.9)
Total non-trading	\$ 123.6	\$ 132.6	\$ 10.9	\$ (259.4)	\$ 7.7
Regulatory net asset (liability)	\$ (76.2)	\$ (83.4)	\$ (5.5)	\$ 259.8	\$ 94.7

Standardized derivative contracts that are valued using market quotations are classified as "values based on quoted market prices from third-party sources." All remaining contracts, which include non-standard contracts and contracts for which market prices are not routinely quoted, are classified as "values based on models and other valuation methods." Both classifications utilize market curves as appropriate for the first six years.

PacifiCorp currently has a non-exchange traded streamflow weather derivative contract to reduce PacifiCorp's exposure to variability in weather conditions that affect hydroelectric generation. Under the agreement, PacifiCorp pays an annual premium in return for the right to make or receive payments if streamflow levels are above or below certain thresholds. PacifiCorp estimates and records an asset or liability corresponding to the total expected future cash flow under the contract in accordance with EITF No. 99-2, *Accounting for Weather Derivatives*. The net asset (liability) recorded for this contract was \$(2.1) million at March 31, 2006 and \$20.3 million at March 31, 2005. PacifiCorp recognized a loss of \$15.6 million for the year ended March 31, 2006; a gain of \$27.9 million for the year ended March 31, 2005; and a gain of \$0.4 million for the year ended March 31, 2004.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of PacifiCorp:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, common shareholder's equity and cash flows present fairly, in all material respects, the financial position of PacifiCorp and its subsidiaries at March 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended March 31, 2006, in conformity with accounting principles generally accepted in the United States of America. 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 of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 3 to the consolidated financial statements, PacifiCorp and its subsidiaries changed the manner in which they apply the normal purchases and normal sales exception to derivative contracts entered into or modified after June 30, 2003, upon their adoption of SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities*, as of July 1, 2003.

As discussed in Note 6 to the consolidated financial statements, PacifiCorp and its subsidiaries changed the manner in which they account for asset retirement obligations upon adoption of SFAS No. 143, *Accounting for Asset Retirement Obligations*, as of April 1, 2003.

PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Portland, Oregon
May 26, 2006

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

(Millions of dollars)

	Years Ended March 31,		
	2006	2005	2004
Revenues	\$ 3,896.7	\$ 3,048.8	\$ 3,194.5
Operating expenses:			
Energy costs	1,545.1	948.0	1,156.7
Operations and maintenance	1,014.5	913.1	895.8
Depreciation and amortization	448.3	436.9	428.8
Taxes, other than income taxes	96.8	94.4	95.3
Total	3,104.7	2,392.4	2,576.6
Income from operations	792.0	656.4	617.9
Interest expense and other (income) expense:			
Interest expense	279.9	267.4	256.5
Interest income	(9.5)	(9.1)	(13.8)
Interest capitalized	(32.4)	(14.8)	(19.9)
Minority interest and other	(6.1)	(7.3)	1.6
Total	231.9	236.2	224.4
Income from operations before income tax expense and cumulative effect of accounting change	560.1	420.2	393.5
Income tax expense	199.4	168.5	144.5
Income before cumulative effect of accounting change	360.7	251.7	249.0
Cumulative effect of accounting change (less applicable income tax benefit of \$(0.6)/2004	-	-	(0.9)
Net income	360.7	251.7	248.1
Preferred dividend requirement	(2.1)	(2.1)	(3.3)
Earnings on common stock	\$ 358.6	\$ 249.6	\$ 244.8

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

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

(Millions of dollars)

ASSETS	March 31.	
	2006	2005
Current assets:		
Cash and cash equivalents	\$ 119.6	\$ 199.3
Accounts receivable less allowance for doubtful accounts of \$11.4/2006 and \$11.6/2005	266.8	293.0
Unbilled revenue	148.2	143.8
Amounts due from affiliates - ScottishPower	-	36.5
Inventories at average costs:		
Materials and supplies	131.2	114.7
Fuel	80.9	58.5
Current derivative contract asset	221.7	252.7
Other	46.9	115.8
Total current assets	1,015.3	1,214.3
Property, plant and equipment:		
Generation	5,686.3	5,238.7
Transmission	2,591.8	2,507.7
Distribution	4,502.8	4,308.7
Intangible plant	659.0	607.0
Other	1,662.5	1,596.9
Total operating assets	15,102.4	14,259.0
Accumulated depreciation and amortization	(5,611.5)	(5,361.8)
Net operating assets	9,490.9	8,897.2
Construction work-in-progress	618.3	593.4
Total property, plant and equipment, net	10,109.2	9,490.6
Other assets:		
Regulatory assets	884.3	972.8
Derivative contract regulatory asset	94.7	170.0
Non-current derivative contract asset	345.3	360.3
Deferred charges and other	282.5	312.9
Total other assets	1,606.8	1,816.0
Total assets	\$ 12,731.3	\$ 12,520.9

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

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS, continued

(Millions of dollars)

	March 31.	
	2006	2005
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	\$ 361.3	\$ 350.4
Amounts due to affiliates - MidAmerican	3.8	-
Amounts due to affiliates - ScottishPower	-	3.9
Accrued employee expenses	118.0	134.3
Taxes payable	47.0	39.8
Interest payable	63.0	64.8
Current derivative contract liability	97.9	136.7
Current deferred tax liability	16.9	2.0
Long-term debt and capital lease obligations, currently maturing	216.9	269.9
Preferred stock subject to mandatory redemption, currently maturing	3.7	3.7
Notes payable and commercial paper	184.4	468.8
Other	103.2	123.4
Total current liabilities	1,216.1	1,597.7
Deferred credits:		
Deferred income taxes	1,621.2	1,629.0
Investment tax credits	67.6	75.6
Regulatory liabilities	804.7	806.0
Non-current derivative contract liability	461.2	630.5
Pension and other post employment liabilities	385.0	422.4
Other	361.4	304.8
Total deferred credits	3,701.1	3,868.3
Long-term debt and capital lease obligations, net of current maturities	3,721.0	3,629.0
Preferred stock subject to mandatory redemption, net of current maturities	41.3	48.8
Total liabilities	8,679.5	9,143.8
Commitments, contingencies and guarantees (See Notes 10 and 11)		
Shareholders' equity:		
Preferred stock	41.3	41.3
Common equity:		
Common shareholder's capital	3,381.9	2,894.1
Retained earnings	630.0	446.4
Accumulated other comprehensive income (loss):		
Unrealized gain on available-for-sale securities, net of tax of \$1.7/2006 and \$2.6/2005	2.7	4.3
Minimum pension liability, net of tax of \$(2.5)/2006 and \$(5.5)/2005	(4.1)	(9.0)
Total common equity	4,010.5	3,335.8
Total shareholders' equity	4,051.8	3,377.1
Total liabilities and shareholders' equity	\$ 12,731.3	\$ 12,520.9

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

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

(Millions of dollars)

	Years Ended March 31.		
	2006	2005	2004
Cash flows from operating activities:			
Net income	\$ 360.7	\$ 251.7	\$ 248.1
Adjustments to reconcile net income to net cash provided by operating activities:			
Cumulative effect of accounting change, net of tax	-	-	0.9
Unrealized gain on derivative contracts, net	(86.8)	(8.4)	(6.1)
Depreciation and amortization	448.3	436.9	428.8
Deferred income taxes and investment tax credits, net	13.9	120.0	80.5
Regulatory asset/liability establishment and amortization	51.6	66.7	111.1
Other	50.0	(27.0)	(6.5)
Changes in:			
Accounts receivable, prepayments and other current assets	71.1	(137.8)	(1.7)
Inventories	(38.9)	(16.2)	14.1
Amounts due to/from affiliates - MidAmerican, net	3.6	-	-
Amounts due to/from affiliates - ScottishPower, net	32.6	(32.8)	(36.8)
Accounts payable and accrued liabilities	(13.4)	84.1	(3.3)
Other	1.9	(26.1)	2.8
Net cash provided by operating activities	894.6	711.1	831.9
Cash flows from investing activities:			
Capital expenditures	(1,049.0)	(851.6)	(690.4)
Proceeds from sales of assets	1.3	7.1	3.3
Proceeds from available-for-sale securities	123.4	49.1	95.8
Purchases of available-for-sale securities	(84.9)	(44.7)	(89.4)
Other	(14.9)	(6.6)	(22.8)
Net cash used in investing activities	(1,024.1)	(846.7)	(703.5)
Cash flows from financing activities:			
Changes in short-term debt	(284.4)	343.9	99.9
Proceeds from long-term debt, net of issuance costs	296.0	395.2	396.7
Proceeds from issuance of common stock to PHI	484.7	-	-
Dividends paid	(177.1)	(195.4)	(165.1)
Repayments and redemptions of long-term debt	(269.7)	(259.8)	(194.1)
Repayment of preferred securities	-	-	(352.0)
Redemptions of preferred stock	(7.5)	(7.5)	(7.5)
Other	7.8	-	(0.3)
Net cash provided by (used in) financing activities	49.8	276.4	(222.4)
Change in cash and cash equivalents	(79.7)	140.8	(94.0)
Cash and cash equivalents at beginning of period	199.3	58.5	152.5
Cash and cash equivalents at end of period	\$ 119.6	\$ 199.3	\$ 58.5

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

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY

(Millions of dollars, thousands of shares)

	Common Shareholder's Capital		Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Comprehensive Income (Loss)
	Shares	Amounts			
Balance at March 31, 2003	312,176	\$ 2,892.1	\$ 305.9	\$ (3.6)	
Comprehensive income					
Net income	-	-	248.1	-	\$ 248.1
Other comprehensive income (loss):					
Unrealized gain on available-for-sale securities, net of tax of \$3.8	-	-	-	6.2	6.2
Minimum pension liability, net of tax of \$(3.8)	-	-	-	(6.1)	(6.1)
Cash dividends declared:					
Preferred stock	-	-	(3.3)	-	-
Common stock (\$0.51 per share)	-	-	(160.6)	-	-
Balance at March 31, 2004	312,176	2,892.1	390.1	(3.5)	\$ 248.2
Comprehensive income					
Net income	-	-	251.7	-	\$ 251.7
Other comprehensive loss:					
Unrealized loss on available-for-sale securities, net of tax of \$(0.1)	-	-	-	(0.2)	(0.2)
Minimum pension liability, net of tax of \$(0.6)	-	-	-	(1.0)	(1.0)
Stock-based compensation expense	-	2.0	-	-	-
Cash dividends declared:					
Preferred stock	-	-	(2.1)	-	-
Common stock (\$0.62 per share)	-	-	(193.3)	-	-
Balance at March 31, 2005	312,176	2,894.1	446.4	(4.7)	\$ 250.5
Comprehensive income					
Net income	-	-	360.7	-	\$ 360.7
Other comprehensive income (loss):					
Unrealized loss on available-for-sale securities, net of tax of \$(0.9)	-	-	-	(1.6)	(1.6)
Minimum pension liability, net of tax of \$3.0	-	-	-	4.9	4.9
Common stock issuance	44,885	484.7	-	-	-
Tax benefit from stock option exercises	-	7.5	-	-	-
Separation of employee benefit plans	-	(3.5)	-	-	-
Other	-	(0.9)	-	-	-
Cash dividends declared:					
Preferred stock	-	-	(2.1)	-	-
Common stock (\$0.53 per share)	-	-	(175.0)	-	-
Balance at March 31, 2006	357,061	\$ 3,381.9	\$ 630.0	\$ (1.4)	\$ 364.0

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

PACIFICORP AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Note 1 - Summary of Significant Accounting Policies

On March 21, 2006, MidAmerican Energy Holdings Company ("MEHC") completed its purchase of all of PacifiCorp's outstanding common stock from PacifiCorp Holdings, Inc. ("PHI"), a subsidiary of Scottish Power plc ("ScottishPower"), pursuant to the Stock Purchase Agreement among MEHC, ScottishPower and PHI dated May 23, 2005, as amended on March 21, 2006. The cash purchase price was \$5.1 billion. PacifiCorp's common stock was directly acquired by a subsidiary of MEHC, PPW Holdings LLC. As a result of this transaction, MEHC controls the significant majority of PacifiCorp's voting securities, which includes both common and preferred stock. MEHC, a global energy company based in Des Moines, Iowa, is a majority-owned subsidiary of Berkshire Hathaway Inc.

Nature of operations - PacifiCorp (which includes PacifiCorp and its subsidiaries) is a United States electricity company serving retail customers in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp generates electricity and also engages in electricity sales and purchases on a wholesale basis. The subsidiaries of PacifiCorp support its electric utility operations by providing coal mining and other fuel-related services, as well as environmental remediation.

As a result of a settlement agreement between MEHC, the Utah Committee of Consumer Services and Utah Industrial Energy Consumers, MEHC contributed to PacifiCorp, at no cost, MEHC's indirect 100.0% ownership interest in Intermountain Geothermal Company, which controls 69.3% of the steam rights associated with the geothermal field serving PacifiCorp's Blundell Geothermal Plant in Utah. Intermountain Geothermal Company therefore became a wholly owned subsidiary of PacifiCorp in March 2006, subsequent to the sale of PacifiCorp to MEHC.

Basis of presentation - The Consolidated Financial Statements of PacifiCorp include its integrated electric utility operations and its wholly owned and majority-owned subsidiaries. Intercompany transactions and balances have been eliminated upon consolidation.

Regulation - Accounting for the electric utility business conforms to accounting principles generally accepted in the United States as applied to regulated public utilities and as prescribed by agencies and the commissions of the various locations in which the electric utility business operates. PacifiCorp prepares its financial statements in accordance with Statement of Financial Accounting Standards ("SFAS") No. 71, *Accounting for the Effects of Certain Types of Regulation* ("SFAS No. 71") as further discussed in Note 2 – Accounting for the Effects of Regulation.

Use of estimates - The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities at the date of the financial statements. These estimates involve judgments with respect to numerous factors that are difficult to predict and are beyond management's control. As a result, actual results could differ materially from these estimates.

Reclassifications - Certain reclassifications of prior years' amounts have been made to conform to the fiscal 2006 method of presentation. These reclassifications had no effect on previously reported consolidated net income.

Cash and cash equivalents - For the purposes of these financial statements, PacifiCorp considers all liquid investments with maturities of three months or less, at the time of acquisition, to be cash equivalents.

Accounts receivable and allowance for doubtful accounts - Accounts receivable includes billed retail and wholesale services plus any accrued and unpaid interest. Credit is granted to customers, which include retail and wholesale customers, government agencies and other utilities. Management performs continuing credit evaluations of customers' financial conditions, and although PacifiCorp does not require collateral, deposits may be required from customers in certain circumstances. Accounts receivable are considered delinquent based on regulations provided by each state, which is generally if payment is not received by the date due, typically 30 days after the invoice date. PacifiCorp charges interest on delinquent customer accounts or past due balances in the states where PacifiCorp does

business based on the respective regulation of each state, and this interest varies between 1.0% to 1.7% per month.

Management reviews accounts receivable on a monthly basis to determine if any receivable will potentially be uncollectible. The allowance for doubtful accounts includes amounts estimated through an evaluation of specific accounts, primarily for wholesale accounts receivable, and a reserve for retail accounts receivable based on historical experience. After all attempts to collect a receivable have failed or, if later, by six months from when a customer becomes inactive, the receivable is written-off against the allowance. Management believes that the allowance for doubtful accounts as of March 31, 2006 was adequate. However, actual write-offs could exceed the recorded allowance. The allowance activity was as follows:

(Millions of dollars)	Years Ended March 31,		
	2006	2005	2004
Beginning balance	\$ 11.6	\$ 23.3	\$ 31.1
Charged to costs and expenses, net (a)	9.2	5.0	5.2
Write-offs, net (b)	(9.4)	(16.7)	(13.0)
Ending balance	<u>\$ 11.4</u>	<u>\$ 11.6</u>	<u>\$ 23.3</u>

- (a) Includes amounts charged to expense for adjustments to the allowance for doubtful accounts, net of recoveries of wholesale accounts receivable.
- (b) Includes write-offs of retail and wholesale accounts receivable, net of recoveries of retail accounts receivable.

Inventories - Inventories are valued at the lower of average cost or market.

Property, plant and equipment - Property, plant and equipment are originally recorded at the cost of contracted services, direct labor and materials, interest capitalized during construction and indirect charges for engineering, supervision and similar overhead items. The cost of depreciable electric utility properties retired, less salvage value, is charged to accumulated depreciation. The cost of removal is charged against the regulatory liability established through depreciation rates. Annual overhaul costs for the replacement of defined retirement units are capitalized. Generally other costs of overhaul activities and other repairs and maintenance are expensed as they are incurred.

Intangible plant consists primarily of computer software costs that are originally recorded at cost. Accumulated amortization on Intangible plant was \$329.8 million at March 31, 2006 and \$307.6 million at March 31, 2005. Amortization expense on Intangible plant was \$45.5 million for the year ended March 31, 2006 and \$48.5 million for the year ended March 31, 2005. The estimated aggregate amortization on Intangible plant for the next five succeeding 12 month periods ending from March 31, 2007 to March 31, 2011 is \$45.4 million, \$38.9 million, \$31.0 million, \$24.7 million and \$21.8 million. Unamortized computer software costs were \$186.7 million at March 31, 2006 and \$185.1 million at March 31, 2005.

Depreciation and amortization - The average depreciable lives of Property, plant and equipment currently in use by category are as follows:

Generation	
Steam plant	20 – 43 years
Hydroelectric plant	14 – 85 years
Other plant	15 – 35 years
Transmission	20 – 70 years
Distribution	44 – 50 years
Intangible plant	5 – 50 years
Other	5 – 30 years

Computer software costs included in Intangible plant are initially assigned a depreciable life of 5 to 10 years.

During the year ended March 31, 2005, PacifiCorp changed the estimated average lives of certain computer software systems to reflect operational plans. This change reduced amortization expense by \$12.9 million annually on existing computer software systems, with an annual impact to net income of approximately \$8.0 million.

Depreciation and amortization are computed by the straight-line method either over the life prescribed by PacifiCorp's various regulatory jurisdictions for regulated assets or over the assets' estimated useful lives. Composite depreciation rates of average depreciable assets on utility Property, plant and equipment (excluding amortization of capital leases) were 3.0% for each of the years ended March 31, 2006, 2005 and 2004.

Asset impairments - Long-lived assets to be held and used by PacifiCorp are reviewed for impairment when events or circumstances indicate costs may not be recoverable. Such reviews are performed in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* ("SFAS No. 144"). The impacts of regulation on cash flows are considered when determining impairment. Impairment losses on long-lived assets are recognized when book values exceed expected undiscounted future cash flows with the impairment measured on a discounted future cash flows basis.

Allowance for funds used during construction - The allowance for funds used during construction (the "AFUDC") represents the cost of debt and may also include equity funds used to finance utility property additions during construction. As prescribed by regulatory authorities, the AFUDC is capitalized as a part of the cost of utility property and is recorded in the Consolidated Statements of Income as Interest capitalized. Under regulatory rate practices, PacifiCorp is generally permitted to recover the AFUDC, and a fair return thereon, through its rate base after the related utility property is placed in service.

The composite capitalization rates were 6.5% for the year ended March 31, 2006; 4.5% for the year ended March 31, 2005; and 7.9% for the year ended March 31, 2004. PacifiCorp's AFUDC rates do not exceed the maximum allowable rates determined by regulatory authorities.

Derivatives - In accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, ("SFAS No. 133"), as amended by SFAS No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities*, and SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities* ("SFAS No. 149") (collectively "SFAS No. 133"), derivative instruments are measured at fair value and recognized as either assets or liabilities on the Consolidated Balance Sheets, unless they qualify for the exemptions afforded by the standard. Changes in the fair value of derivatives are recognized in earnings during the period of change. Certain long-term derivative contracts have been approved by regulatory authorities for recovery through retail rates. Accordingly, changes in fair value of these contracts are deferred as regulatory assets or liabilities pursuant to SFAS No. 71. Derivative contracts for commodities used in PacifiCorp's normal business operation and that settle by physical delivery, among other criteria, are eligible for the normal purchases and normal sales exemption afforded by SFAS No. 133. These contracts are accounted for under accrual accounting and recorded in Revenues or Energy costs in the Consolidated Statements of Income when the contracts settle.

Marketable securities - PacifiCorp accounts for marketable securities, included in Deferred charges and other on PacifiCorp's Consolidated Balance Sheets, in accordance with SFAS No. 115, *Accounting for Certain Investments in Debt and Equity Securities*. PacifiCorp determines the appropriate classification of all marketable securities as held-to-maturity, available-for-sale or trading at the time of purchase and re-evaluates such classification as of each balance sheet date. As shown in Note 5 – Marketable Securities, at March 31, 2006 and 2005, all of PacifiCorp's investments in marketable securities were classified as available-for-sale and were reported at fair value. PacifiCorp uses the specific identification method in computing realized gains and losses on the sale of its available-for-sale securities. Realized gains and losses are included in Other (income) expense. Unrealized gains and losses are reported as a component of Accumulated other comprehensive income (loss). Investments that are in loss positions as of the end of each reporting period are analyzed to determine whether they have experienced a decline in market value that is considered other-than-temporary. An investment will generally be written down to market value if it has a significant unrealized loss for more than nine months. If additional information is available that indicates an investment is other-than-temporarily impaired, it will be written down prior to the nine-month time period. If an

investment has been impaired for more than nine months but available information indicates that the impairment is temporary, the investment will not be written down.

Amounts held in trust – PacifiCorp holds certain trusts to fund decommissioning and reclamation activities as described in Note 5 – Marketable Securities and Note 6 – Asset Retirement Obligations and Accrued Environmental Costs. Amounts are also held in trusts that serve as funding vehicles for certain of PacifiCorp's employee benefits, including the Supplemental Executive Retirement Plan (the "SERP") as described in Note 17 – Employee Benefits.

Asset retirement obligations and accrued removal costs - Effective April 1, 2003, PacifiCorp recognizes the fair value of legal obligations associated with the retirement or removal of long-lived assets at the time the obligations are incurred and can be reasonably estimated in accordance with SFAS No. 143, *Accounting for Asset Retirement Obligations* ("SFAS No. 143"). The initial recognition of this liability is accompanied by a corresponding increase in Property, plant and equipment. Subsequent to the initial recognition, the liability is adjusted for any revisions to the expected value of the retirement obligation (with corresponding adjustments to Property, plant and equipment) and for accretion of the liability due to the passage of time. Additional depreciation expense is recorded prospectively for any Property, plant and equipment increases. In general, depreciation and accretion expense generated by SFAS No. 143 accounting is recorded as a regulatory asset or liability because such amounts are recoverable in rates. As of March 31, 2006, PacifiCorp adopted Financial Accounting Standards Board (the "FASB") Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations – an Interpretation of FASB Statement No. 143* ("FIN 47") as described in Note 6 – Asset Retirement Obligations and Accrued Environmental Costs.

For those asset retirement removal costs that do not meet the requirements of SFAS No. 143, PacifiCorp recovers through approved depreciation rates estimated removal costs and accumulates such amounts in Asset retirement removal costs within Regulatory liabilities as described in Note 2 – Accounting for the Effects of Regulation.

Income taxes - PacifiCorp uses the liability method of accounting for deferred income taxes. Deferred tax liabilities and assets reflect the expected future tax consequences, based on enacted tax law, of temporary differences between the tax bases of assets and liabilities and their financial reporting amounts.

Prior to the sale of PacifiCorp to MEHC on March 21, 2006, PacifiCorp was a wholly owned subsidiary of PHI. Therefore, it was included in the consolidated income tax return for PHI from April 1, 2003 through March 21, 2006. PacifiCorp currently is an indirect, majority-owned subsidiary of Berkshire Hathaway Inc. and is included in its consolidated income tax return. PacifiCorp's provision for income taxes has been computed on the basis that it files separate consolidated income tax returns with its subsidiaries.

Historically, PacifiCorp did not recognize deferred taxes on many of the timing differences between book and tax depreciation. In prior years, these benefits were flowed through to the utility customer as prescribed by PacifiCorp's various regulatory jurisdictions. Deferred income tax liabilities and Regulatory assets have been established for those flow-through tax benefits as shown in Note 2 – Accounting for the Effects of Regulation since PacifiCorp is allowed to recover the increased income tax expense when these differences reverse.

Investment tax credits are deferred and amortized to income over periods prescribed by PacifiCorp's various regulatory jurisdictions.

PacifiCorp establishes accruals for certain tax contingencies when, despite the belief that its tax return positions are supported, it also believes that certain positions may be challenged and that it is probable those positions may not be fully sustained. PacifiCorp is under continuous examination by the Internal Revenue Service and other tax authorities and accounts for potential losses of tax benefits in accordance with SFAS No. 5, *Accounting for Contingencies* ("SFAS No. 5"). See Note 19 – Income Taxes for further information.

Stock-based compensation - As permitted by SFAS No. 123, *Accounting for Stock-Based Compensation* ("SFAS No. 123"), PacifiCorp accounts for its stock-based compensation arrangements, primarily employee stock options, under the intrinsic value recognition and measurement principles of Accounting Principles Board ("APB") Opinion No. 25, *Accounting for Stock Issued to Employees* ("APB No. 25"), and related interpretations in accounting for employee stock options issued to PacifiCorp employees. Under APB No. 25, because the exercise price of employee stock options equals the market price of the underlying stock on the date of grant, no compensation expense is

recorded if the ultimate number of shares to be awarded is known at the date of the grant. All options currently

accounted for under APB No. 25 were issued in ScottishPower American Depository Shares, as discussed in Note 18 – Stock-Based Compensation. Had PacifiCorp determined compensation cost based on the fair value at the grant date for all stock options vesting in each period under SFAS No. 123, PacifiCorp's Net income would have been reduced to the pro forma amounts below:

(Millions of dollars)	Years Ended March 31.		
	2006	2005	2004
Net income as reported	\$ 360.7	\$ 251.7	\$ 248.1
Add: stock-based compensation included in reported net income, net of related tax effects	0.1	3.1	-
Less: stock-based compensation expense using the fair value method, net of related tax effects	(1.4)	(4.3)	(1.1)
Pro forma net income	<u>\$ 359.4</u>	<u>\$ 250.5</u>	<u>\$ 247.0</u>

Revenue recognition - Revenue is recognized upon delivery for retail and wholesale electricity sales. Electricity sales to retail customers are determined based on meter readings taken throughout the month. PacifiCorp accrues an estimate of unbilled revenues, which are earned but not yet billed, net of estimated line losses, each month for electric service provided after the meter reading date to the end of the month. The process of calculating the Unbilled revenue estimate consists of three components: quantifying PacifiCorp's total electricity delivered during the month, assigning Unbilled revenues to customer type and valuing the unbilled energy. Factors involved in the estimation of consumption and line losses relate to weather conditions, amount of natural light, historical trends, economic impacts and customer type. Valuation of unbilled energy is based on estimating the average price for the month for each customer type. The amount accrued for Unbilled revenues was \$148.2 million at March 31, 2006 and \$143.8 million at March 31, 2005.

Segment information - PacifiCorp currently has one segment, which includes the regulated retail and wholesale electric operations.

New accounting standards -

SFAS No. 123R

On April 1, 2006, PacifiCorp adopted SFAS No. 123R, *Share-Based Payment* ("SFAS No. 123R"), a revision of the originally issued SFAS No. 123. SFAS No. 123R establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services. SFAS No. 123R requires that the cost resulting from all share-based payment transactions be recognized in the financial statements using the fair value method. The intrinsic value method of accounting established by APB No. 25 will no longer be allowed. The adoption of SFAS No. 123R did not have an effect on PacifiCorp's financial position or results of operations as all requisite service has been rendered by employees and the outstanding stock awards are fully vested. For further information see Note 18 – Stock-Based Compensation.

EITF No. 04-6

On April 1, 2006, PacifiCorp adopted Emerging Issues Task Force No. 04-6, *Accounting for Stripping Costs Incurred during Production in the Mining Industry* ("EITF No. 04-6"). EITF No. 04-6 requires that stripping costs incurred during the production phase of a mine are variable production costs that should be included in the costs of the inventory produced (that is, extracted) during the period that the stripping costs are incurred. The adoption of EITF No. 04-6 did not have a material impact on PacifiCorp's consolidated financial position or results of operations.

Note 2 - Accounting for the Effects of Regulation

Regulated utilities have historically applied the provisions of SFAS No. 71, which is based on the premise that regulators will set rates that allow for the recovery of a utility's costs, including cost of capital. Accounting under SFAS No. 71 is appropriate as long as (i) rates are established by or subject to approval by independent, third-party regulators, (ii) rates are designed to recover the specific enterprise's cost of service, and (iii) in view of demand for service, it is reasonable to assume that rates are set at levels that will recover costs and can be collected from customers.

SFAS No. 71 provides that regulatory assets may be capitalized if it is probable that future revenue in an amount at least equal to the capitalized costs will result from their treatment as allowable costs for rate-making purposes. In addition, the rate action should permit recovery of the specific previously incurred costs rather than provide for expected levels of similar future costs. PacifiCorp records regulatory assets and liabilities based on management's assessment that it is probable that a cost will be recovered (asset) or that an obligation has been incurred (liability). The final outcome, or additional regulatory actions, could change management's assessment in future periods. A regulator can provide current rates intended to recover costs that are expected to be incurred in the future, with the understanding that if those costs are not incurred, future rates will be reduced by corresponding amounts. If current rates are intended to recover such costs, PacifiCorp recognizes amounts charged pursuant to such rates as liabilities and takes those amounts to income only when the associated costs are incurred. In applying SFAS No. 71, PacifiCorp must give consideration to changes in the level of demand or competition during the cost recovery period. In accordance with SFAS No. 71, PacifiCorp capitalizes certain costs as regulatory assets if authorized to recover the costs in future periods.

PacifiCorp continuously evaluates the appropriateness of applying SFAS No. 71 to each of its jurisdictions. At March 31, 2006, PacifiCorp had recorded specifically identified net regulatory assets of \$174.3 million. In the event PacifiCorp stopped applying SFAS No. 71 at March 31, 2006, an after-tax loss of approximately \$108.2 million would be recognized.

PacifiCorp is subject to the jurisdiction of public utility regulatory authorities of each of the states in which it conducts retail electric operations with respect to prices, services, accounting, issuance of securities and other matters. The jurisdictions in which PacifiCorp operates are in various stages of evaluating deregulation. At present, PacifiCorp is subject to cost-based rate-making for its business. PacifiCorp is a "licensee" and a "public utility" as those terms are used in the Federal Power Act and is, therefore, subject to regulation by the Federal Energy Regulatory Commission (the "FERC") as to accounting policies and practices, certain prices and other matters.

Regulatory assets include the following:

(Millions of dollars)	March 31.	
	2006 (a)	2005 (a)
Deferred income taxes (b)	\$ 480.3	\$ 499.9
Minimum pension liability (c)	257.7	280.7
Unamortized issuance expense on retired debt	29.0	34.6
Demand-side resource costs	13.4	25.5
Transition plan - retirement and severance	16.9	24.9
Various other costs	87.0	107.2
Subtotal	884.3	972.8
Derivative contracts (d)	94.7	170.0
Total	\$ 979.0	\$ 1,142.8

- (a) PacifiCorp had regulatory assets not accruing carrying charges of \$952.9 million at March 31, 2006 and \$1,095.6 million at March 31, 2005.
- (b) Represents accelerated income tax benefits previously passed on to ratepayers that will be included in rates concurrently with recognition of the associated income tax expense.

- (c) Represents minimum pension liability offsets proportionate to the amount of pension costs that are recoverable in rates. Remaining minimum pension liability offsets are included net of tax in Accumulated other comprehensive income (loss).
- (d) Represents net unrealized losses related to derivative contracts included in rates. See Note 3 – Derivative Instruments for further information.

Regulatory liabilities include the following:

(Millions of dollars)	March 31.	
	2006	2005
Asset retirement removal costs (a)	\$ 699.8	\$ 692.1
Deferred income taxes	43.7	44.4
Bonneville Power Administration Regional Exchange Program	23.3	12.6
Various other costs	37.9	56.9
Total	<u>\$ 804.7</u>	<u>\$ 806.0</u>

- (a) Represents removal costs recovered in rates.

PacifiCorp evaluates the recovery of all regulatory assets periodically and as events occur. The evaluation includes the probability of recovery, as well as changes in the regulatory environment. Regulatory and/or legislative action in Utah, Oregon, Wyoming, Washington, Idaho and California may require PacifiCorp to record regulatory asset write-offs and charges for impairment of long-lived assets in future periods. Impairment would be measured in accordance with PacifiCorp's asset impairment policy, as discussed in Note 1 – Summary of Significant Accounting Policies.

Note 3 - Derivative Instruments

In accordance with SFAS No. 133, PacifiCorp records derivative instruments on the Consolidated Balance Sheets as assets or liabilities measured at estimated fair value, unless they qualify for the exemptions afforded by the standard. PacifiCorp uses derivative instruments (primarily forward purchases and sales) to manage the commodity price risk inherent in its fuel and electricity obligations, as well as to optimize the value of power generation assets and related contracts.

In July 2003, the EITF issued EITF No. 03-11, *Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not "Held for Trading Purposes"* as defined in Issue No. 02-3 ("EITF No. 03-11"), which provides guidance on whether to report realized gains or losses on physically settled derivative contracts not held for trading purposes on a gross or net basis and requires realized gains or losses on derivative contracts that do not settle physically to be reported on a net basis. The adoption of EITF No. 03-11 during the year ended March 31, 2004 resulted in PacifiCorp netting certain contracts that were previously recorded on a gross basis in Wholesale sales and other revenues and Energy costs in the Consolidated Statements of Income. The adoption of EITF No. 03-11 had no impact on PacifiCorp's consolidated Net income and all periods presented are consistent with the requirements of EITF 03-11.

As the FASB continues to issue interpretations, PacifiCorp may change the conclusions that it has reached and, as a result, the accounting treatment and financial statement impact could change in the future.

The accounting treatment for the various classifications of derivative financial instruments is as follows:

Normal purchases and normal sales - The contracts that qualify as normal purchases and normal sales are excluded from the requirements of SFAS No. 133. The realized gains and losses on these contracts are reflected in the Consolidated Statements of Income at the contract settlement date.

Undesignated - Unrealized gains and losses on derivative contracts held for trading purposes are presented on a net basis in the Consolidated Statements of Income as Revenues. Unrealized gains and losses on derivative contracts not held for trading purposes are presented in the Consolidated Statements of Income as Revenues for sales contracts and as Energy costs and Operations and maintenance expense for purchase contracts and financial swaps.

PacifiCorp has the following types of commodity transactions:

Wholesale electricity purchase and sales contracts - PacifiCorp makes continuing projections of future retail and wholesale loads and future resource availability to meet these loads based on a number of criteria, including historical load and forward market and other economic information and experience. Based on these projections, PacifiCorp purchases and sells electricity on a forward yearly, quarterly, monthly, daily and hourly basis to match actual resources to actual energy requirements and sells any surplus at the prevailing market price. This process involves hedging transactions, which include the purchase and sale of firm energy under long-term contracts, forward physical contracts or financial contracts for the purchase and sale of a specified amount of energy at a specified price over a given period of time.

Natural gas and other fuel purchase contracts - PacifiCorp manages its natural gas supply requirements by entering into forward commitments for physical delivery of natural gas. PacifiCorp also manages its exposure to increases in natural gas supply costs through forward commitments for the purchase of physical natural gas at fixed prices and financial swap contracts that settle in cash based on the difference between a fixed price that PacifiCorp pays and a floating market-based price that PacifiCorp receives.

Where PacifiCorp's derivative instruments are subject to a master netting agreement and the criteria of FIN 39, *Offsetting of Amounts Related to Certain Contracts- An Interpretation of APB Opinion No. 10 and FASB Statement No. 105*, are met, PacifiCorp presents its derivative assets and liabilities, as well as accompanying receivables and payables, on a net basis in the accompanying Consolidated Balance Sheets.

Unrealized gains and losses on energy sales and purchase contracts are affected by fluctuations in forward prices for electricity and natural gas. The following table summarizes the amount of the pre-tax unrealized gains and losses included within the Consolidated Statements of Income associated with changes in the fair value of PacifiCorp's derivative contracts that are not included in rates.

(Millions of dollars)	Years Ended March 31,		
	2006	2005	2004
Revenues	\$ 224.4	\$ (330.0)	\$ (29.4)
Operating expenses:			
Energy costs	(131.1)	338.4	35.5
Operations and maintenance	(6.5)	-	-
Total unrealized gain on derivative contracts	<u>\$ 86.8</u>	<u>\$ 8.4</u>	<u>\$ 6.1</u>

The following table shows the changes in the fair value of energy-related contracts subject to the requirements of SFAS No. 133, as amended, from April 1, 2005 to March 31, 2006.

(Millions of dollars)	Net Asset (Liability)		Regulatory Net Asset (Liability) (b)
	Trading	Non-trading	
Fair value of contracts outstanding at March 31, 2005	\$ 0.2	\$ (154.4)	\$ 170.0
Contracts realized or otherwise settled during the period	(0.2)	(115.8)	128.3
Other changes in fair values (a)	0.2	277.9	(203.6)
Fair value of contracts outstanding at March 31, 2006	<u>\$ 0.2</u>	<u>\$ 7.7</u>	<u>\$ 94.7</u>

- (a) Other changes in fair values include the effects of changes in market prices, inflation rates and interest rates, including those based on models, on new and existing contracts.
- (b) Net unrealized losses (gains) related to derivative contracts included in rates are recorded as a regulatory net asset (liability).

PacifiCorp bases its forward price curves upon market price quotations when available and bases them on internally developed and commercial models, with internal and external fundamental data inputs, when market quotations are unavailable. Market quotes are obtained from independent energy brokers, as well as direct information received from third-party offers and actual transactions executed by PacifiCorp. Price quotations for certain major electricity trading hubs are generally readily obtainable for the first six years and therefore PacifiCorp's forward price curves for those locations and periods reflect observable market quotes. However, in the later years or for locations that are not actively traded, forward price curves must be developed. For short-term contracts at less actively traded locations, prices are modeled based on observed historical price relationships with actively traded locations. For long-term contracts extending beyond six years, the forward price curve (beyond the first six years) is based upon the use of a fundamentals model (cost-to-build approach) due to the limited information available. The fundamentals model is updated as warranted, at least quarterly, to reflect changes in the market such as long-term natural gas prices and expected inflation rates.

Short-term contracts, without explicit or embedded optionality, are valued based upon the relevant portion of the forward price curve. Contracts with explicit or embedded optionality are valued by separating each contract into its physical and financial forward, swap and option components. Forward and swap components are valued against the appropriate forward price curve. The optionality is valued using a modified Black-Scholes model approach or a stochastic simulation (Monte Carlo) approach. Each option component is modeled and valued separately using the appropriate forward price curve.

Standardized derivative contracts that are valued using market quotations, as described above, are classified in the table below as "values based on quoted market prices from third-party sources." All remaining contracts, which include non-standard contracts and contracts for which market prices are not routinely quoted, are classified as "values based on models and other valuation methods."

	Fair Value of Contracts at Period-End				
	Maturity Less Than 1 Year	Maturity 1-3 Years	Maturity 4-5 Years	Maturity in Excess of 5 Years	Total Fair Value
(Millions of dollars)					
Trading:					
Values based on quoted market prices from third-party sources	\$ 0.2	\$ -	\$ -	\$ -	\$ 0.2
Non-trading:					
Values based on quoted market prices from third-party sources	\$ 58.7	\$ 49.7	\$ 6.0	\$ 1.2	\$ 115.6
Values based on models and other valuation methods	64.9	82.9	4.9	(260.6)	(107.9)
Total non-trading	\$ 123.6	\$ 132.6	\$ 10.9	\$ (259.4)	\$ 7.7
Regulatory net asset (liability)	\$ (76.2)	\$ (83.4)	\$ (5.5)	\$ 259.8	\$ 94.7

Weather derivatives - PacifiCorp currently has a non-exchange traded streamflow weather derivative contract to reduce PacifiCorp's exposure to variability in weather conditions that affect hydroelectric generation. Under the agreement, PacifiCorp pays an annual premium in return for the right to make or receive payments if streamflow levels are above or below certain thresholds. PacifiCorp estimates and records an asset or liability corresponding to the total expected future cash flow under the contract in accordance with EITF No. 99-2, *Accounting for Weather Derivatives*. The net asset (liability) recorded for this contract was \$(2.1) million at March 31, 2006 and \$20.3 million at March 31, 2005 and was included in other current assets (liabilities) in the Consolidated Balance Sheets. PacifiCorp recognized a loss of \$15.6 million for the year ended March 31, 2006; a gain of \$27.9 million for the year ended March 31, 2005; and a gain of \$0.4 million for the year ended March 31, 2004.

Note 4 – Related-Party Transactions

Transactions while owned by MEHC – As discussed in Note 1 – Summary of Significant Accounting Policies, PacifiCorp was acquired by MEHC on March 21, 2006. The following describes PacifiCorp's transactions and balances with unconsolidated related parties while owned by MEHC.

PacifiCorp began participating in a captive insurance program provided by MEHC Insurance Services Ltd. ("MISL"), a wholly owned subsidiary of MEHC. MISL covers all or significant portions of the property damage and liability insurance deductibles in many of PacifiCorp's current policies, as well as overhead distribution and transmission line property damage. PacifiCorp has no equity interest in MISL and has no obligation to contribute equity or loan funds to MISL. Premium amounts are established based on a combination of actuarial assessments and market rates to cover loss claims, administrative expenses and appropriate reserves. Certain costs associated with the program are prepaid and amortized over the policy coverage period expiring March 20, 2007. Prepayments to MISL were \$7.2 million at March 31, 2006. Premium expenses were \$0.2 million for March 21, 2006 through March 31, 2006.

As of March 31, 2006, Amounts due to affiliates - MEHC included \$3.8 million of current income taxes payable to PPW Holdings LLC.

See Note 1 – Summary of Significant Accounting Policies for information related to the transfer of MEHC's 100.0% ownership interest in Intermountain Geothermal Company to PacifiCorp.

Transactions while owned by ScottishPower - There were no loans or advances between PacifiCorp and ScottishPower or between PacifiCorp and PHI. Loans from PacifiCorp to ScottishPower or PHI were prohibited under the Public Utility Holding Company Act of 1935 ("PUHCA"), which was repealed effective February 2006. Loans from ScottishPower or PHI to PacifiCorp generally required state regulatory and SEC approval. There were intercompany loan agreements that allowed funds to be lent to PacifiCorp from PacifiCorp Group Holdings Company ("PGHC"), but loans from PacifiCorp to PGHC were prohibited. There were intercompany loan agreements that allowed funds to be lent between PacifiCorp and Pacific Minerals, Inc., a wholly owned subsidiary of PacifiCorp. PacifiCorp does not maintain a centralized cash or money pool. Therefore, funds of each company were not commingled with funds of any other company.

The tables below detail PacifiCorp's transactions and balances with unconsolidated related parties while owned by ScottishPower.

(Millions of dollars)	March 31, 2006 *	March 31, 2005
Amounts due from former affiliated entities:		
SPUK (a)	\$ -	\$ 0.3
PHI and its subsidiaries (b)	-	36.2
	<u>\$ -</u>	<u>\$ 36.5</u>
Prepayments to former affiliated entities:		
PHI and its subsidiaries (c)	\$ -	\$ 1.5
Amounts due to former affiliated entities:		
SPUK (d)	\$ -	\$ 3.9
Deposits received from former affiliated entities:		
PHI and its subsidiaries (e)	\$ -	\$ 0.3

(Millions of dollars)	Years Ended March 31.		
	2006	2005	2004
Revenues from former affiliated entities:			
PHI and its subsidiaries (e)	\$ 7.8	\$ 5.9	\$ 4.4
Expenses recharged to former affiliated entities:			
SPUK (a)	\$ 6.2	\$ 3.0	\$ 0.7
PHI and its subsidiaries (b)	7.3	9.4	8.0
	<u>\$ 13.5</u>	<u>\$ 12.4</u>	<u>\$ 8.7</u>
Expenses incurred from former affiliated entities:			
SPUK (d)	\$ 18.6	\$ 18.3	\$ 7.8
PHI and its subsidiaries (c)	19.3	17.3	17.0
DIIL (f)	7.0	-	-
	<u>\$ 44.9</u>	<u>\$ 35.6</u>	<u>\$ 24.8</u>
Interest expense to former affiliated entities:			
PHI and its subsidiaries (g)	\$ -	\$ 0.1	\$ 0.2

* Amounts settled at close of sale to MEHC.

- (a) For the years ended March 31, 2006 and 2005, receivables and expenses included amounts allocated to Scottish Power UK plc ("SPUK"), an indirect subsidiary of ScottishPower, by PacifiCorp for administrative services provided under ScottishPower's affiliated interest cross-charge policy. For the year ended March 31, 2006, expenses also included costs associated with retention agreements and severance benefits reimbursed by SPUK. In addition, PacifiCorp recharged to SPUK payroll costs and related benefits of PacifiCorp employees working on international assignment in the United Kingdom for ScottishPower during the years ended March 31, 2006, 2005 and 2004.
- (b) Amounts shown pertain to activities of PacifiCorp with its former parent PHI and its subsidiaries. Expenses recharged reflect costs for support services to PHI and its subsidiaries. Amounts due from PHI and its subsidiaries included \$33.8 million as of March 31, 2005 of income taxes receivable from PHI. PHI was the tax-paying entity while PacifiCorp was owned by ScottishPower.
- (c) These expenses primarily related to operating lease payments for the West Valley facility, located in Utah and owned by West Valley Leasing Company, LLC ("West Valley"). West Valley is a subsidiary of PPM Energy, Inc. ("PPM"), which is a subsidiary of PHI. The lease is a 15 year operating lease on an electric generation facility. The facility consists of five generating units each with a nameplate rating of 43.4 MW. Certain costs associated with the West Valley lease are prepaid on an annual basis. Lease expense was \$16.4

million for the year ended March 31, 2006; \$17.1 million for the year ended March 31, 2005; and \$17.0 million for the year ended March 31, 2004. PacifiCorp has an option to terminate the West Valley lease if written notice is provided to West Valley on or before December 1, 2006. If the option to terminate is exercised, the lease would terminate in May 2008. PacifiCorp is committed to future minimum lease payments of \$10.0 million annually for each of the 12 months ending March 31, 2007 and 2008 and \$1.7 million for the two months ending May 31, 2008. These minimum future lease payments reflect the reduction in monthly payments resulting from a March 2006 amendment to the lease terms.

- (d) These liabilities and expenses primarily represented amounts allocated to PacifiCorp by SPUK for administrative services received under the cross-charge policy. Cross-charges from SPUK to PacifiCorp amounted to \$16.7 million for the year ended March 31, 2006 and \$14.9 million for the year ended March 31, 2005. These costs were recorded in Operations and maintenance expense. SPUK also recharged PacifiCorp for payroll costs and related benefits of SPUK employees working on international assignment with PacifiCorp in the United States.
- (e) These revenues and the associated deposits related to wheeling services billed to PPM. PacifiCorp provided these services to PPM pursuant to PacifiCorp's FERC-approved open access transmission tariff, which required PacifiCorp to make transmission services available on a non-discriminatory basis to all interested parties.
- (f) PacifiCorp began participating in a captive insurance program provided by Dornoch International Insurance Limited ("DIIL"), an indirect wholly owned consolidated subsidiary of ScottishPower, in May 2005. DIIL covered all or significant portions of the property damage and liability insurance deductibles in many of PacifiCorp's policies, as well as overhead distribution and transmission line property damage. PacifiCorp had no equity interest in DIIL and had no obligation to contribute equity or loan funds to DIIL. Premium amounts were established to cover loss claims, administrative expenses and appropriate reserves, but otherwise DIIL was not operated to generate profits.
- (g) Included interest on short-term demand loans made to PacifiCorp by PGHC, in accordance with regulatory authorization.

Note 5 – Marketable Securities

PacifiCorp, by contract with Idaho Power, the minority owner of Bridger Coal Company (an indirect subsidiary of PacifiCorp), maintains a trust relating to final reclamation of a leased coal mining property. Amounts funded are based on estimated future reclamation costs and estimated future coal deliveries. Trust fund assets associated with Bridger Coal Company recorded at fair value included in Deferred charges and other were \$101.9 million at March 31, 2006 and \$92.4 million at March 31, 2005, including the Idaho Power minority-interest portion. Minority interest in Bridger Coal Company was \$49.5 million at March 31, 2006 and \$26.2 million at March 31, 2005. See also Note 6 – Asset Retirement Obligations and Accrued Environmental Costs.

The amortized cost and fair value of reclamation trust securities and other investments included in Deferred charges and other on PacifiCorp's Consolidated Balance Sheets, which are classified as available-for-sale, were as follows:

(Millions of dollars)	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
March 31, 2006				
Debt securities	\$ 25.9	\$ 0.2	\$ (0.6)	\$ 25.5
Equity securities	61.7	7.0	(0.7)	68.0
Total	\$ 87.6	\$ 7.2	\$ (1.3)	\$ 93.5
March 31, 2005				
Mutual fund account (a)	\$ 27.0	\$ -	\$ (1.0)	\$ 26.0
Debt securities	25.6	0.4	(0.4)	25.6
Equity securities	60.6	13.2	(1.2)	72.6
Total	\$ 113.2	\$ 13.6	\$ (2.6)	\$ 124.2

- (a) In October 2005, the mutual fund account was transferred to a money market account.

The quoted market price of securities is used to estimate their fair value.

The amortized cost and estimated fair value of debt securities at March 31, 2006 and 2005 by contractual maturities and of equity securities for the same dates are shown below. Actual maturities may differ from contractual maturities because borrowers may have the right to call or prepay obligations with or without call or prepayment penalties.

(Millions of dollars)	March 31.			
	2006		2005	
	Amortized Cost	Estimated Fair Value	Amortized Cost	Estimated Fair Value
Debt securities				
Due in one year or less	\$ 0.7	\$ 0.6	\$ 0.7	\$ 0.7
Due after one year through five years	6.5	6.4	5.6	5.6
Due after five years through ten years	9.9	9.8	9.8	9.9
Due after ten years	8.8	8.7	9.5	9.4
Mutual fund account	-	-	27.0	26.0
Equity securities	61.7	68.0	60.6	72.6
Total	<u>\$ 87.6</u>	<u>\$ 93.5</u>	<u>\$ 113.2</u>	<u>\$ 124.2</u>

Proceeds, gross gains and gross losses from realized sales of available-for-sale securities using the specific identification method were as follows for the years ended March 31, 2006, 2005 and 2004:

(Millions of dollars)	Years Ended March 31.		
	2006	2005	2004
Proceeds	<u>\$ 123.4</u>	<u>\$ 49.1</u>	<u>\$ 95.8</u>
Gross gains	\$ 16.6	\$ 6.3	\$ 6.5
Gross losses	(2.3)	(2.2)	(3.4)
Net gains	14.3	4.1	3.1
Less net gains included in Regulatory liabilities (a)	(16.6)	(5.6)	(3.2)
Net losses included in Net income	<u>\$ (2.3)</u>	<u>\$ (1.5)</u>	<u>\$ (0.1)</u>

- (a) Realized gains and losses on the Bridger Coal Company reclamation trust described above are recorded as a regulatory liability in accordance with the prescribed regulatory treatment.

Note 6 – Asset Retirement Obligations and Accrued Environmental Costs

Asset Retirement Obligations - PacifiCorp records asset retirement obligations for long-lived physical assets that qualify as legal obligations under SFAS No. 143. PacifiCorp estimates its asset retirement obligation liabilities based upon detailed engineering calculations of the amount and timing of the future cash spending for a third party to perform the required work. Spending estimates are escalated for inflation and then discounted at a credit-adjusted, risk-free rate. PacifiCorp then records an asset retirement obligation asset associated with the liability. The asset retirement obligation assets are depreciated over their expected lives and the asset retirement obligation liabilities are accreted to the projected spending date. Changes in estimates could occur due to plan revisions, changes in estimated costs and changes in timing of the performance of reclamation activities. In addition, PacifiCorp records removal costs as a part of depreciation expense in accordance with regulatory accounting requirements described in Note 2 – Accounting for the Effects of Regulation. Since asset retirement costs are recovered through the ratemaking process, PacifiCorp records a regulatory asset or regulatory liability on the Consolidated Balance Sheets to account for the difference between asset retirement costs as currently approved in rates and costs under SFAS No. 143.

PacifiCorp does not recognize liabilities for asset retirement obligations for which the fair value cannot be reasonably estimated. PacifiCorp has asset retirement obligations associated with its transmission and distribution systems and certain coal mines. However, due to the indeterminate removal date, the fair value of the associated liabilities currently cannot be estimated and no amounts are recognized in the Consolidated Financial Statements.

In March 2005, the FASB issued FIN 47. FIN 47 clarifies that an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation when incurred if the fair value of the liability can be reasonably estimated. Upon adoption of FIN 47 at March 31, 2006, PacifiCorp recorded an asset retirement obligation liability at a net present value of \$22.7 million. PacifiCorp also increased net depreciable assets by \$1.8 million, reclassified \$13.5 million of costs accrued for retirement removals from regulatory liabilities to asset retirement obligation liabilities, increased regulatory liabilities by \$0.4 million and increased regulatory assets by \$7.8 million for the difference between retirement costs approved by regulators and obligations under FIN 47.

The pro forma total asset retirement obligation liability balances that would have been reported assuming FIN 47 had been adopted on April 1, 2004, rather than March 31, 2006, are as follows:

(Millions of dollars)

Pro forma asset retirement obligation liability at April 1, 2004	\$215.8
Pro forma asset retirement obligation liability at March 31, 2005	\$222.1

Due to regulatory accounting treatment, the adoption of FIN 47 would have no material impact on net income for the pro forma periods listed above and had no impact on PacifiCorp's reported cash flows.

The following table describes the changes to PacifiCorp's asset retirement obligation liability for the years ended March 31, 2006 and 2005:

(Millions of dollars)	March 31, 2006	March 31, 2005
Liability recognized at beginning of period	\$ 199.6	\$ 193.5
Liabilities incurred (a)	25.2	1.4
Liabilities settled (b)	(10.4)	(13.0)
Revisions in cash flow (c)	(11.2)	8.9
Accretion expense	8.9	8.8
Asset retirement obligation	212.1	199.6
Less current portion (d)	7.0	17.8
Long-term asset retirement obligation at end of period (e)	\$ 205.1	\$ 181.8

- (a) Relates primarily to the adoption of FIN 47 at March 31, 2006.
- (b) Relates primarily to ongoing reclamation work at the Glenrock coal mine.
- (c) Results from changes in the timing and amounts of estimated cash flows for certain plant reclamation.
- (d) Amount included in Other current liabilities on the Consolidated Balance Sheets.
- (e) Amount included in Deferred credits - other on the Consolidated Balance Sheets.

PacifiCorp had trust fund assets recorded at fair value included in Deferred charges and other of \$103.0 million at March 31, 2006 and \$93.4 million at March 31, 2005 relating to mine and plant reclamation, including the minority-interest joint-owner portions.

Accrued Environmental Costs – PacifiCorp's policy is to accrue environmental cleanup-related costs of a non-capital nature when those costs are believed to be probable and can be reasonably estimated. The quantification of environmental exposures is based on assessments of many factors, including changing laws and regulations, advancements in environmental technologies, the quality of information available related to specific sites, the assessment stage of each site investigation, preliminary findings and the length of time involved in remediation or settlement. PacifiCorp hires external consultants from time to time to conduct studies in order to establish reserves

for various site environmental remediation costs. PacifiCorp is subject to cost-sharing agreements with other potentially responsible parties based on decrees, orders and other legal agreements. In these circumstances, PacifiCorp assesses the financial capability of other potentially responsible parties and the reasonableness of PacifiCorp's apportionment. These agreements may affect the range of potential loss. Additionally, PacifiCorp may benefit from excess insurance policies that may cover some of the cleanup costs if costs incurred exceed certain amounts.

PacifiCorp assesses its potential obligations to perform environmental remediation on an ongoing basis. As a result of studies performed during the year ended March 31, 2006, PacifiCorp increased its reserve by \$9.7 million to reflect its most likely estimate for probable liabilities. Remediation costs that are fixed and determinable have been discounted to their present value using credit-adjusted, risk-free discount rates based on the expected future annual borrowing rates of PacifiCorp. The liability recorded was \$38.5 million at March 31, 2006 and \$33.3 million at March 31, 2005 and is included as part of Deferred credits - other. The March 31, 2006 recorded liability included \$18.1 million of discounted liabilities. Had none of the liabilities included in the \$38.5 million balance recorded at March 31, 2006 been discounted, the total would have been \$40.7 million. The expected payments for each of the five 12 month periods ending March 31 and thereafter are as follows: \$5.4 million in 2007, \$3.9 million in 2008, \$2.4 million in 2009, \$1.5 million in 2010, \$1.2 million in 2011 and \$26.3 million thereafter.

It is possible that future findings or changes in estimates could require that additional amounts be accrued. Should current circumstances change, it is possible that PacifiCorp could incur an additional undiscounted obligation of up to approximately \$53.1 million relating to existing sites. However, management believes that completion or resolution of these matters will have no material adverse effect on PacifiCorp's consolidated financial position or results of operations.

Note 7 - Notes Payable and Commercial Paper

Amounts outstanding under PacifiCorp's short-term notes payable and commercial paper arrangements were as follows:

(Millions of dollars)	Balance	Average Interest Rate
March 31, 2006	\$ 184.4	4.8 %
March 31, 2005	468.8	2.9

Revolving Credit Agreement

PacifiCorp amended and restated its existing \$800.0 million committed bank revolving credit agreement in August 2005. Changes included an increase to 65.0% in the covenant not to exceed a specified debt-to-capitalization percentage, extension of the termination date to August 29, 2010 and exclusion of the acquisition of PacifiCorp by MEHC as an event of default under the agreement. As of March 31, 2006, PacifiCorp's revolving credit agreement was fully available and had no borrowings outstanding. The interest on advances under this facility is generally based on the London Interbank Offered Rate (LIBOR) plus a margin that varies based on PacifiCorp's credit ratings. This facility supports PacifiCorp's commercial paper program and \$38.1 million of variable rate pollution control revenue bonds.

PacifiCorp's revolving credit agreement contains customary covenants and default provisions and PacifiCorp monitors these covenants on a regular basis. As of March 31, 2006, PacifiCorp was in compliance with the covenants of its revolving credit agreement.

Note 8 - Long-Term Debt and Capital Lease Obligations

PacifiCorp's long-term debt and capital lease obligations were as follows:

(Millions of dollars)	March 31,			
	2006		2005	
	Amount	Average Interest Rate	Amount	Average Interest Rate
<u>First mortgage bonds</u>				
4.3% to 8.8%, due through 2011	\$ 901.7	6.0 %	\$ 1,171.4	6.2 %
5.0% to 9.2%, due 2012 to 2016	1,040.4	6.5	1,040.4	6.5
8.5% to 8.6%, due 2017 to 2021	5.0	8.5	5.0	8.5
6.7% to 8.5%, due 2022 to 2026	424.0	7.4	424.0	7.4
5.3 % to 7.7%, due 2032 to 2036	800.0	6.3	500.0	7.0
Unamortized discount	(4.7)		(4.3)	
<u>Guaranty of pollution-control revenue bonds</u>				
Variable rates, due 2014 (a) (b)	40.7	3.1	40.7	2.3
Variable rates, due 2014 to 2026 (b)	325.2	3.2	325.2	2.3
Variable rates, due 2025 (a) (b)	175.8	3.2	175.8	2.3
3.4% to 5.7%, due 2014 to 2026 (a)	184.0	4.5	184.0	4.5
6.2%, due 2031	12.7	6.2	12.7	6.2
Unamortized discount	(0.5)		(0.5)	
Funds held by trustees	(2.2)		(2.1)	
<u>Capital lease obligations</u>				
10.4% to 14.8%, due through 2035	35.8	11.7	26.6	11.9
Total	3,937.9		3,898.9	
Less current maturities	(216.9)		(269.9)	
Total	<u>\$ 3,721.0</u>		<u>\$ 3,629.0</u>	

- (a) Secured by pledged first mortgage bonds generally at the same interest rates, maturity dates and redemption provisions as the pollution-control revenue bonds.
- (b) Interest rates fluctuate based on various rates, primarily on certificate of deposit rates, interbank borrowing rates, prime rates or other short-term market rates.

First mortgage bonds of PacifiCorp may be issued in amounts limited by PacifiCorp's property, earnings and other provisions of the mortgage indenture. Approximately \$13.8 billion of the eligible assets (based on original cost) of PacifiCorp are subject to the lien of the mortgage.

Approximately \$2.3 billion of first mortgage bonds were redeemable at PacifiCorp's option at March 31, 2006 at redemption prices dependent upon United States Treasury yields. Approximately \$541.7 million of variable-rate pollution-control revenue bonds were redeemable at PacifiCorp's option at par at March 31, 2006. Approximately \$71.2 million of fixed-rate pollution-control revenue bonds were redeemable at PacifiCorp's option at par at March 31, 2006. The remaining long-term debt was not redeemable at March 31, 2006.

In September 2005, the SEC declared effective PacifiCorp's shelf registration statement covering \$700.0 million of future first mortgage bond and unsecured debt issuances. PacifiCorp has not yet issued any of the securities covered by this registration statement.

In June 2005, PacifiCorp issued \$300.0 million of its 5.25% Series of First Mortgage Bonds due June 15, 2035. PacifiCorp used the proceeds for the reduction of short-term debt, including the short-term debt used in December 2004 to redeem its 8.625% Series of First Mortgage Bonds due December 13, 2024 totaling \$20.0 million.

In March 2005, the maturity dates were extended to December 1, 2020 for three series of variable-rate pollution-control revenue bonds totaling \$38.1 million.

PacifiCorp leases equipment and real estate in various states in which it does business under long-term agreements, extending through March 2035, which are classified as capital leases. These capital leases are payable in monthly installments allocated between principal and imputed interest rates ranging from 10.4% to 14.8%.

In April 2005, PacifiCorp entered into a 30-year transportation service agreement with Questar Pipeline Company for the right to use a newly constructed pipeline facility with a majority of the output designated to provide natural gas to the Currant Creek Power Plant. This agreement qualifies as a capital lease with an initial net present value lease obligation of \$12.4 million at an imputed interest rate of 11.3%.

The annual maturities of long-term debt and capital lease obligations for the 12 months ending March 31 are:

(Millions of dollars)	Long-term Debt	Capital Lease Obligations	Total
2007	\$ 216.3	\$ 4.8	\$ 221.1
2008	119.9	4.8	124.7
2009	412.4	4.8	417.2
2010	138.5	5.0	143.5
2011	14.6	4.9	19.5
Thereafter	3,007.8	63.8	3,071.6
	3,909.5	88.1	3,997.6
Unamortized discount	(5.2)	-	(5.2)
Funds held by trustee	(2.2)	-	(2.2)
Amounts representing interest	-	(52.3)	(52.3)
	<u>\$ 3,902.1</u>	<u>\$ 35.8</u>	<u>\$ 3,937.9</u>

PacifiCorp made interest payments, net of capitalized interest, of \$240.3 million for the year ended March 31, 2006; \$220.4 million for the year ended March 31, 2005; and \$236.7 million for the year ended March 31, 2004.

At March 31, 2006, PacifiCorp had \$517.8 million of standby letters of credit and standby bond purchase agreements available to provide credit enhancement and liquidity support for variable-rate pollution-control revenue bond obligations. In addition, PacifiCorp had approximately \$40.5 million of standby letters of credit to provide credit support for certain transactions as requested by third parties. These committed bank arrangements were all fully available as of March 31, 2006 and expire periodically through the 12 months ending March 31, 2011.

PacifiCorp's standby letters of credit and standby bond purchase agreements generally contain similar covenants to those contained in PacifiCorp's revolving credit agreement, although the maximum permitted debt-to-capitalization ratio for one of the standby bond purchase agreements was 60.0% as of March 31, 2006 and was amended in May 2006 to now permit a maximum ratio of 65.0%. See Note 7 – Notes Payable and Commercial Paper for further information. PacifiCorp monitors these covenants on a regular basis in order to ensure that events of default will not occur and as of March 31, 2006, PacifiCorp was in compliance with the covenants of these agreements.

Note 9 – Preferred Stock Subject to Mandatory Redemption

PacifiCorp's Preferred stock subject to mandatory redemption was as follows:

(Thousands of shares, millions of dollars) Series	March 31, 2006		March 31, 2005	
	Shares	Amount	Shares	Amount
Preferred stock subject to mandatory redemption				
\$7.48 No Par Serial Preferred, \$100 stated value, 16,000 shares authorized	<u>450</u>	<u>\$ 45.0</u>	<u>525</u>	<u>\$ 52.5</u>

PacifiCorp has mandatory redemption requirements on 37,500 shares of the \$7.48 series Preferred stock on June 15, 2006, with a non-cumulative option to redeem an additional 37,500 shares on June 15, 2006, at \$100.0 per share, plus accrued and unpaid dividends to the date of such redemption. All outstanding shares on June 15, 2007 are subject to mandatory redemption. Holders of Preferred stock subject to mandatory redemption are entitled to certain voting rights and may have the right to elect members to the PacifiCorp Board of Directors in the event dividends payable are in default in an amount equal to four full quarterly payments. PacifiCorp redeemed \$7.5 million of Preferred stock subject to mandatory and optional redemption during each of the years ended March 31, 2006, 2005 and 2004.

PacifiCorp had \$0.8 million at March 31, 2006 and \$1.0 million at March 31, 2005 in dividends declared but unpaid on Preferred stock subject to mandatory redemption that were included in Interest payable.

Note 10 - Commitments and Contingencies

PacifiCorp follows SFAS No. 5, to determine accounting and disclosure requirements for contingencies. PacifiCorp operates in a highly regulated environment. Governmental bodies such as the FERC, state regulatory commissions, the SEC, the Internal Revenue Service, the Department of Labor, the United States Environmental Protection Agency (the "EPA") and others have authority over various aspects of PacifiCorp's business operations and public reporting. Reserves are established when required in management's judgment, and disclosures regarding litigation, assessments and creditworthiness of customers or counterparties, among others, are made when appropriate. The evaluation of these contingencies is performed by various specialists inside and outside of PacifiCorp.

From time to time, PacifiCorp is also a party to various legal claims, actions, complaints and disputes, certain of which involve material amounts. PacifiCorp has recorded \$6.7 million in reserves as of March 31, 2006 related to various outstanding legal actions and disputes, excluding those discussed below. This amount represents PacifiCorp's best estimate of probable losses related to these matters. PacifiCorp currently believes that disposition of these matters will not have a material adverse effect on PacifiCorp's consolidated financial position, results of operations or liquidity.

Environmental matters - PacifiCorp is subject to numerous environmental laws, including the federal Clean Air Act and various state air quality laws; the Endangered Species Act, particularly as it relates to certain endangered species of fish; the Comprehensive Environmental Response, Compensation and Liability Act, and similar state laws relating to environmental cleanups; the Resource Conservation and Recovery Act and similar state laws relating to the storage and handling of hazardous materials; and the Clean Water Act, and similar state laws relating to water quality. These laws could potentially impact future operations. Environmental contingencies identified at March 31, 2006 principally consist of air quality matters. Pending or proposed air regulations will require PacifiCorp to reduce its electricity plant emissions of sulfur dioxide, nitrogen oxides and other pollutants below current levels. These reductions will be required to address regional haze programs, mercury emissions regulations and possible re-interpretations and changes to the federal Clean Air Act. In the future, PacifiCorp expects to incur significant costs to comply with various stricter air emissions requirements. These potential costs are expected to consist primarily of capital expenditures. PacifiCorp expects these costs would be included in rates and, as such, would not have a material adverse impact on PacifiCorp's consolidated results of operations. See also Note 6 – Asset Retirement Obligations and Accrued Environmental Costs.

Hydroelectric relicensing - PacifiCorp's hydroelectric portfolio consists of 51 plants with an aggregate plant net capability of 1,159.4 MW. The FERC regulates 93.9% of the installed capacity of this portfolio through 18 individual licenses. Several of PacifiCorp's hydroelectric projects are in some stage of relicensing under the Federal Power Act. Hydroelectric relicensing and the related environmental compliance requirements are subject to uncertainties. PacifiCorp expects that future costs relating to these matters may be significant and will consist primarily of additional relicensing costs, operations and maintenance expense, and capital expenditures. Electricity generation reductions may result from the additional environmental requirements. PacifiCorp had incurred \$70.3 million in costs as of March 31, 2006 for ongoing hydroelectric relicensing, which are reflected in Construction work-in-progress on the Consolidated Balance Sheet. PacifiCorp expects that these and future costs will be included in rates and, as such, will not have a material adverse impact on PacifiCorp's consolidated financial position or results of operations.

In October 2005, the new FERC license for the North Umpqua hydroelectric project became final under the terms of the North Umpqua Settlement Agreement. Prior to this date, the license had been effective, but not final, because environmental groups had challenged its legality before the FERC and in federal court. In September 2005, the Ninth Circuit Court of Appeals issued an order upholding the new license. Since the Court's order was not appealed within the allowed time, all legal challenges of the FERC license order have been exhausted and the license is final for purposes of recording liabilities. PacifiCorp is committed, over the 35-year life of the license, to fund approximately \$48.4 million for environmental mitigation and enhancement projects. As a result of the license becoming final, PacifiCorp recorded additional liabilities and intangible assets in October 2005 amounting to a present value of \$11.2 million. At March 31, 2006, the liability recorded for all North Umpqua obligations amounted to a present value of \$21.8 million.

FERC Issues

California Refund Case - PacifiCorp is a party to a FERC proceeding that is investigating potential refunds for energy transactions in the California Independent System Operator and the California Power Exchange markets during past periods of high energy prices. PacifiCorp has a reserve of \$17.7 million for these potential refunds. PacifiCorp's ultimate exposure to refunds is dependent upon any order issued by the FERC in this proceeding. In addition, beginning in summer 2000, California market conditions resulted in defaults of amounts due to PacifiCorp from certain counterparties resulting from transactions with the California Independent System Operator and California Power Exchange. PacifiCorp has reserved \$5.0 million for these receivables.

FERC Market Power Analysis - Pursuant to the FERC's orders granting PacifiCorp authority to sell capacity and energy at market-based rates, PacifiCorp and certain of its former affiliates had been required to submit a joint market power analysis every three years. Under the FERC's current policy, applicants must demonstrate that they do not possess market power in order to charge market-based rates for sales of wholesale energy and capacity in the applicants' control areas. An analysis demonstrating an applicant's passage of certain threshold screens for assessing generation market power establishes a rebuttable presumption that the applicant does not possess generation market power, while failure to pass any screen creates a rebuttable presumption that the applicant has generation market power. In February 2005, PacifiCorp submitted a joint triennial market power analysis in compliance with the FERC's requirements. The analysis indicated that PacifiCorp failed to pass one of the generation market power screens in PacifiCorp's eastern control area and in Idaho Power Company's control area. In May 2005, the FERC issued an order instituting a proceeding pursuant to section 206 of the Federal Power Act to determine whether PacifiCorp may continue to charge market-based rates for sales of wholesale energy and capacity. Under the terms of the order, PacifiCorp and its formerly affiliated co-applicants were required to submit additional information and analysis to the FERC within 60 days to rebut the presumption that PacifiCorp has generation market power. In June and July 2005, PacifiCorp filed additional analysis in response to the FERC's May 2005 order. In January 2006, the FERC requested PacifiCorp to amend its previous filings with additional analysis, which was filed in March 2006. If the FERC ultimately finds that PacifiCorp has market power, PacifiCorp will be required to implement measures to mitigate any exercise of market power, which may result in decreased revenues and/or increased operating expenses. PacifiCorp believes the outcome of this proceeding will not have a material impact on its consolidated financial position or results of operations.

Note 11 – Guarantees and Other Commitments

Guarantees

PacifiCorp is generally required to obtain state regulatory commission approval prior to guaranteeing debt or obligations of other parties. In November 2002, the FASB issued Interpretation No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others* ("FIN 45"). FIN 45 requires disclosure of certain direct and indirect guarantees.

The following represent the indemnification obligations of PacifiCorp as of March 31, 2006 and 2005.

PacifiCorp has made certain commitments related to the decommissioning or reclamation of certain jointly owned facilities and mine sites. The decommissioning guarantees require PacifiCorp to pay a proportionate share of the decommissioning costs based upon percentage of ownership. The mine reclamation obligations require PacifiCorp to pay the mining entity a proportionate share of the mine's reclamation costs based on the amount of coal purchased by

PacifiCorp. In the event of default by any of the other joint participants, PacifiCorp potentially may be obligated to absorb, directly or by paying additional sums to the entity, a proportionate share of the defaulting party's liability. PacifiCorp has recorded its estimated share of the decommissioning and reclamation obligations as either an asset retirement obligation, regulatory liability or other liability.

In connection with the sale of PacifiCorp's Montana service territory, PacifiCorp entered into a purchase and sale agreement with Flathead Electric Cooperative in October 1998. Under the agreement, PacifiCorp indemnified Flathead Electric Cooperative for losses, if any, occurring after the closing date and arising as a result of certain breaches of warranty or covenants. The indemnification has a cap of \$10.1 million until October 2008 and a cap of \$5.1 million thereafter (less expended costs to date). Two indemnity claims relating to environmental issues have been tendered, but remediation costs for these claims, if any, are not expected to be material.

From time to time, PacifiCorp executes contracts that include indemnities typical for the underlying transactions, which are related to sales of businesses, property, plant and equipment, and service territories. These indemnities might include any of the following matters: privacy rights; governmental regulations and employment-related issues; commercial contractual relationships; financial reports; tax-related issues; securities laws; and environmental-related issues. Performance under these indemnities generally would be triggered by breach of representations and warranties in the contract. PacifiCorp regularly evaluates the probability of having to incur costs under the indemnities and appropriately accrues for expected losses that are probable and estimable. Some of these indemnities may not limit potential liability; therefore, PacifiCorp is unable to estimate a maximum potential amount of future payments that could result from claims made under these indemnities. PacifiCorp believes that the likelihood that it would be required to perform or otherwise incur any significant losses associated with any of these obligations is remote.

Unconditional Purchase Obligations

(Millions of dollars)	Payments due during the 12 months ending March 31.						Total
	2007	2008	2009	2010	2011	Thereafter	
Construction	\$ 111.4	\$ 33.2	\$ -	\$ -	\$ -	\$ -	\$ 144.6
Operating leases	15.0	15.3	2.9	2.1	2.1	8.8	46.2
Purchased electricity	756.3	426.7	284.1	290.6	258.0	2,146.7	4,162.4
Transmission	45.7	39.5	37.7	35.3	36.8	503.3	698.3
Fuel	516.8	600.5	522.5	452.7	339.8	1,931.5	4,363.8
Other	52.6	61.0	59.5	53.6	53.4	837.0	1,117.1
Total commitments	<u>\$ 1,497.8</u>	<u>\$ 1,176.2</u>	<u>\$ 906.7</u>	<u>\$ 834.3</u>	<u>\$ 690.1</u>	<u>\$ 5,427.3</u>	<u>\$ 10,532.4</u>

Construction - PacifiCorp has an ongoing construction program to meet increased electricity usage, customer growth and system reliability objectives. At March 31, 2006, PacifiCorp had estimated long-term unconditional purchase obligations for construction of the new Lake Side Power Plant.

Operating leases - PacifiCorp leases offices, certain operating facilities, land and equipment under operating leases that expire at various dates through the 12 months ended March 31, 2093. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. These leases generally require PacifiCorp to pay for insurance, taxes and maintenance applicable to the leased property. Excluded from the operating lease payments above are any power purchase agreements that meet the definition of an operating lease.

Net rent expense was \$28.8 million for the year ended March 31, 2006; \$26.1 million for the year ended March 31, 2005; and \$29.4 million for the year ended March 31, 2004.

Minimum non-cancelable sublease rent payments expected to be received through the 12 months ended March 31, 2013 total \$6.8 million.

Purchased electricity - As part of its energy resource portfolio, PacifiCorp acquires a portion of its electricity through long-term purchases and/or exchange agreements. Included in the purchased electricity payments above are any power purchase agreements that meet the definition of an operating lease.

Included in the minimum fixed annual payments for purchased electricity above are commitments to purchase electricity from several hydroelectric projects under long-term arrangements with public utility districts. These purchases are made on a "cost-of-service" basis for a stated percentage of project output and for a like percentage of project operating expenses and debt service. These costs are included in Energy costs in the Consolidated Statements of Income. PacifiCorp is required to pay its portion of operating costs and its portion of the debt service, whether or not any electricity is produced.

At March 31, 2006, PacifiCorp's share of long-term arrangements with public utility districts was as follows:

(Millions of dollars)

<u>Generating Facility</u>	<u>Year Contract Expires</u>	<u>Capacity (MW)</u>	<u>Percentage of Output</u>	<u>Annual Costs (a)</u>
Wanapum	2009	194.1	18.7 %	\$ 6.6
Rocky Reach	2011	67.8	5.3	3.6
Priest Rapids	2045	61.0	6.5	2.0
Wells	2018	58.3	6.9	2.1
Total		<u>381.2</u>		<u>\$ 14.3</u>

(a) Includes debt service totaling \$7.0 million.

PacifiCorp's minimum debt service and estimated operating obligations included in purchased electricity above for the 12 months ending March 31 are as follows:

<u>(Millions of dollars)</u>	<u>Minimum Debt Service</u>	<u>Operating Obligations</u>
2007	\$ 9.3	\$ 8.3
2008	9.3	8.4
2009	9.3	8.6
2010	4.7	4.8
2011	4.7	4.9
Thereafter	<u>55.5</u>	<u>84.3</u>
	<u>\$ 92.8</u>	<u>\$ 119.3</u>

PacifiCorp has a 4.0% entitlement to the generation of the Intermountain Power Project, located in central Utah, through a power purchase agreement. PacifiCorp and the City of Los Angeles have agreed that the City of Los Angeles will purchase capacity and energy from PacifiCorp's 4.0% entitlement of the Intermountain Power Project at a price equivalent to 4.0% of the expenses and debt service of the project.

Fuel - PacifiCorp has "take or pay" coal and natural gas contracts that require minimum payments.

Other - Unconditional purchase obligations, as defined by accounting standards, are those long-term commitments that are non-cancelable or cancelable only under certain conditions. PacifiCorp has such commitments related to legal or contractual asset retirement obligations, environmental obligations, hydroelectric obligations, equipment maintenance and various other service and maintenance agreements.

Resource Management

PacifiCorp, as a public utility and a franchise supplier, has an obligation to manage resources to supply its customers. Rates charged to most customers are tariff rates authorized by regulatory agencies as discussed in Note 2 – Accounting for the Effects of Regulation.

Note 12 - Jointly Owned Facilities

At March 31, 2006, PacifiCorp's share in jointly owned facilities was as follows:

(Millions of dollars)	PacifiCorp Share	Plant in Service	Accumulated Depreciation/ Amortization	Construction Work-in- Progress
Jim Bridger Nos. 1 - 4 (a)	66.7 %	\$ 922.2	\$ 467.6	\$ 18.3
Wyodak	80.0	308.8	165.9	14.8
Hunter No. 1	93.8	307.7	142.5	1.8
Colstrip Nos. 3 and 4 (a)	10.0	239.2	116.2	1.5
Hunter No. 2	60.3	212.2	99.4	8.1
Hermiston (b)	50.0	167.0	38.9	1.6
Craig Station Nos. 1 and 2	19.3	165.3	71.3	0.7
Hayden Station No. 1	24.5	41.1	18.6	1.0
Foote Creek	78.8	36.3	10.4	-
Hayden Station No. 2	12.6	26.4	12.8	0.3
Trojan (c)	2.5	-	-	-
Other transmission and distribution plants	Various	78.6	21.2	-
Unallocated acquisition adjustments (d)		157.2	75.8	-
Total		<u>\$ 2,662.0</u>	<u>\$ 1,240.6</u>	<u>\$ 48.1</u>

- (a) Includes kilovolt lines and substations.
- (b) Additionally, PacifiCorp has contracted to purchase the remaining 50.0% of the output of the Hermiston Plant. See Note 13 – Consolidation of Variable-Interest Entities.
- (c) The Trojan Plant was closed in 1993 and PacifiCorp is allowed recovery of costs associated with the plant over the remaining life of the original license. Plant, inventory, fuel and decommissioning costs totaling \$8.1 million relating to the Trojan Plant were included in regulatory assets at March 31, 2006.
- (d) Represents the excess of the costs of the acquired interests in purchased facilities over their original net book values.

Under the joint ownership agreements, each participating utility is responsible for financing its share of construction, operating and leasing costs. PacifiCorp's portion is recorded in its applicable construction work-in-progress, operations, maintenance and tax accounts, which is consistent with wholly owned plants.

Note 13 – Consolidation of Variable-Interest Entities

In December 2003, the FASB issued revised FIN 46, *Consolidation of Variable-Interest Entities, an interpretation of Accounting Research Bulletin No. 51* ("FIN 46R"), which requires existing unconsolidated variable-interest entities ("VIEs") to be consolidated by their primary beneficiaries if the entities do not effectively disperse risks among parties involved. FIN 46R was adopted as of January 1, 2004 and resulted in disclosures describing identifiable variable interests.

VIE's Required to be Consolidated

PacifiCorp holds an undivided interest in 50.0% of the 474-MW Hermiston Plant (see Note 12 – Jointly Owned Facilities), procures 100.0% of the fuel input into the plant and subsequently receives 100.0% of the generated electricity, 50.0% of which is acquired through a long-term purchase power agreement. As a result, PacifiCorp holds a variable interest in the joint owner of the remaining 50.0% of the plant and is the primary beneficiary. However,

upon adoption of FIN 46R, PacifiCorp was unable to obtain the information necessary to consolidate the entity, because the entity did not agree to supply the information due to the lack of a contractual obligation to do so. PacifiCorp continues to request from the entity the information necessary to perform the consolidation; however, no information has yet been provided by the entity. Electricity purchased from the joint owner was \$35.2 million during the year ended March 31, 2006; \$34.8 million during the year ended March 31, 2005; and \$33.7 million during the year ended March 31, 2004. The entity is operated by the equity owners, and PacifiCorp has no risk of loss in relation to the entity in the event of a disaster.

Significant Variable-Interests in VIE's not Required to be Consolidated

As discussed in Note 4 – Related-Party Transactions, PacifiCorp leases the West Valley facility from a former affiliate under an operating lease that contains purchase options at specified prices. Although the purchase options are variable-interests in West Valley, PacifiCorp is not the primary beneficiary of the entity. PacifiCorp's exposure to loss under the operating lease is negligible.

PacifiCorp is a party to certain operating and coal purchase agreements with Trapper Mining, Inc. that create a variable interest under the provisions of FIN 46R. Trapper Mining, Inc. owns and operates the Trapper Mine near Craig, Colorado, and produces 100.0% of its output for the benefit of the Craig Power Plant. PacifiCorp has a 21.4% equity interest in Trapper Mining, Inc. and also holds a 19.3% undivided interest in the Craig Power Plant as disclosed in Note 12 – Jointly Owned Facilities. Since each equity investor in Trapper Mining, Inc. also holds a similar interest in the Craig Power Plant, and since none of the joint owners have more than a 50.0% interest in the Craig Power Plant or Trapper Mining, Inc., none of the joint owners are required to consolidate Trapper Mining, Inc. Accordingly, PacifiCorp will continue to account for its interest in Trapper Mining, Inc. via the equity method under APB No. 18, *The Equity Method of Accounting for Investments in Common Stock*, as in prior periods.

Note 14 – Preferred Stock

PacifiCorp's Preferred stock was as follows:

(Thousands of shares, millions of dollars, except per share amounts)	Redemption Price	March 31, 2006		March 31, 2005	
Series	Per Share	Shares	Amount	Shares	Amount
Preferred stock not subject to mandatory redemption					
Serial Preferred, \$100 stated value, 3,500 shares authorized					
4.52 %	\$ 103.5	2	\$ 0.2	2	\$ 0.2
4.56	102.3	85	8.4	85	8.4
4.72	103.5	70	6.9	70	6.9
5.00	100.0	42	4.2	42	4.2
5.40	101.0	66	6.6	66	6.6
6.00	Non-redeemable	6	0.6	6	0.6
7.00	Non-redeemable	18	1.8	18	1.8
5% Preferred, \$100 stated value, 127 shares authorized					
	110.0	126	12.6	126	12.6
		415	\$ 41.3	415	\$ 41.3

Generally, Preferred stock is redeemable at stipulated prices plus accrued dividends, subject to certain restrictions. Upon voluntary liquidation, all Preferred stock is entitled to stated value or a specified preference amount per share plus accrued dividends. Upon involuntary liquidation, all Preferred stock is entitled to stated value plus accrued dividends. Any premium paid on redemptions of Preferred stock is capitalized, and recovery is sought through future rates. Dividends on all Preferred stock are cumulative. Holders also have the right to elect members to the PacifiCorp Board of Directors in the event dividends payable are in default in an amount equal to four full quarterly payments.

PacifiCorp had \$0.5 million at both March 31, 2006 and March 31, 2005 in dividends declared but unpaid on Preferred stock. The shares and amounts outstanding for each series of Preferred stock not subject to mandatory redemption were unchanged from March 31, 2004 through March 31, 2006.

Note 15 - Common Shareholder's Equity

Common Shareholder's Equity - PacifiCorp has one class of common stock with no par value. A total of 750,000,000 shares were authorized and 357,060,915 shares were issued and outstanding at March 31, 2006 and 312,176,089 shares were issued and outstanding at March 31, 2005. During the year ended March 31, 2006, PacifiCorp issued 44,884,826 shares of its common stock to PHI, its former parent company, at a total price of \$484.7 million. The proceeds from the sale of the shares were used to repay short-term debt.

On March 20, 2006, immediately prior to the closing of PacifiCorp's sale to MEHC, PacifiCorp paid a dividend on common stock, at that time held by PHI, in the aggregate amount of \$16.8 million. The dividend was reduced pursuant to Amendment No. 1 to the Stock Purchase Agreement among MEHC, ScottishPower and PHI executed on the date of the transaction's closing from the \$56.6 million aggregate amount originally declared by the PacifiCorp Board of Directors on January 27, 2006.

In the past, to the extent PacifiCorp did not reimburse ScottishPower for stock-based compensation awarded under ScottishPower plans, such amounts increased the value of PacifiCorp's common shareholder's capital.

Common Dividend Restrictions - MEHC is the sole indirect shareholder of PacifiCorp's common stock. The state regulatory orders that authorized the acquisition of PacifiCorp by MEHC contain restrictions on PacifiCorp's ability to pay dividends to the extent that they would reduce PacifiCorp's common stock equity below specified percentages of defined capitalization.

As of March 31, 2006, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to PPW Holdings LLC or MEHC without prior state regulatory approval to the extent that it would reduce PacifiCorp's common stock equity below 48.25% of its total capitalization, excluding short-term debt and current maturities of long-term debt. After December 31, 2008, this minimum level of common equity declines annually to 44.0% after December 31, 2011. The terms of this commitment treat 50.0% of PacifiCorp's preferred stock outstanding prior to the acquisition of PacifiCorp by MEHC as common equity. As of March 31, 2006, PacifiCorp's actual common stock equity percentage, as calculated under this measure, exceeded the minimum threshold.

In addition, PacifiCorp is restricted from making any distributions to PPW Holdings LLC or MEHC if PacifiCorp's unsecured debt rating is BBB- or lower by Standard & Poor's Rating Services or Fitch Ratings or Baa3 or lower by Moody's Investor Service, as indicated by two of the three rating services. As of March 31, 2006, PacifiCorp's unsecured debt rating was BBB+ by Standard & Poor's Rating Services and Fitch Ratings and Baa1 by Moody's Investor Service.

PacifiCorp is also subject to maximum debt-to-total capitalization levels under various debt agreements.

Note 16 - Fair Value of Financial Instruments

(Millions of dollars)	March 31, 2006		March 31, 2005	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt (a)	\$ 3,902.1	\$ 4,091.4	\$ 3,872.3	\$ 4,209.5
Preferred stock subject to mandatory redemption	45.0	46.3	52.5	56.0

(a) Includes long-term debt classified as currently maturing, less capital lease obligations.

The carrying value of cash and cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximates fair value because of the short-term maturity of these instruments.

The fair value of PacifiCorp's long-term debt, current maturities of long-term debt and redeemable preferred stock has been estimated by discounting projected future cash flows, using the current rate at which similar loans would be made to borrowers with similar credit ratings and for the same maturities.

Note 17 - Employee Benefits

PacifiCorp sponsors defined benefit pension plans that cover the majority of its employees and also provides health care and life insurance benefits through various plans for eligible retirees. The measurement date for plan assets and obligations is December 31 of each year.

As a result of the sale of PacifiCorp to MEHC, plan participants that were employees or retirees of certain ScottishPower affiliates and a former PacifiCorp mining subsidiary ceased to participate in PacifiCorp's plans. This separation resulted in a net \$3.5 million reduction in Common shareholder's capital.

Pension Plans

PacifiCorp's pension plans include the PacifiCorp Retirement Plan (the "Retirement Plan"), the SERP and a joint trust plan to which PacifiCorp contributes on behalf of certain bargaining unit employees of IBEW Local 57. Benefits under the Retirement Plan are based on the employee's years of service and average monthly pay in the 60 consecutive months of highest pay out of the last 120 months, with adjustments to reflect benefits estimated to be received from social security. Pension costs are funded annually by no more than the maximum amount that can be deducted for federal income tax purposes.

Components of the net periodic pension benefit cost (income) are summarized as follows:

(Millions of dollars)	Years Ended March 31,		
	2006	2005	2004
Service cost (a)	\$ 32.2	\$ 25.9	\$ 25.8
Interest cost	74.4	73.8	73.9
Expected return on plan assets (b)	(76.9)	(77.7)	(80.7)
Amortization of unrecognized net transition obligation	8.4	8.4	8.4
Amortization of unrecognized prior service cost	1.2	1.4	1.5
Amortization of unrecognized loss	21.5	8.5	-
Cost of termination benefits	3.0	-	-
Net periodic pension benefit cost	<u>\$ 63.8</u>	<u>\$ 40.3</u>	<u>\$ 28.9</u>

- (a) Includes contributions to the PacifiCorp/IBEW Local 57 Retirement Trust Fund of \$1.4 million for the year ended March 31, 2006; no contributions for the year ended March 31, 2005; and contributions of \$5.6 million for the year ended March 31, 2004.
- (b) The market-related value of plan assets, among other factors, is used to determine expected return on plan assets and is calculated by spreading the difference between expected and actual investment returns over a five-year period beginning in the first year in which they occur.

The weighted-average rates assumed in the actuarial calculations used to determine the net periodic benefit costs for the pension and postretirement benefit plans were as follows:

	Years Ended March 31.		
	2006	2005	2004
Discount rate	5.75 %	6.25 %	6.75 %
Expected long-term rate of return on assets	8.75	8.75	8.75
Rate of increase in compensation levels	4.00	4.00	4.00

PacifiCorp determined the long-term rate of return based on historical asset class returns and current market conditions, taking into account the diversification benefits of investing in multiple asset classes.

The weighted-average rates assumed in the actuarial calculations used to determine benefit obligations for the pension and postretirement benefit plans were as follows:

	March 31.		
	2006	2005	2004
Discount rate	5.75 %	5.75 %	6.25 %
Rate of increase in compensation levels	4.00	4.00	4.00

The change in the projected benefit obligation, change in plan assets and funded status of the pension plans are as follows:

(Millions of dollars)	March 31,	
	2006	2005
<u>Change in projected benefit obligation</u>		
Projected benefit obligation - beginning of year	\$ 1,338.1	\$ 1,229.8
Service cost	30.8	25.9
Interest cost	74.4	73.8
Plan amendments	2.9	1.0
Cost of termination benefits	3.0	-
Separation of former participants	(44.3)	-
Actuarial loss	22.9	86.8
Benefits paid	(84.1)	(79.1)
Transfers	(1.5)	(0.1)
Projected benefit obligation - end of year	<u>\$ 1,342.2</u>	<u>\$ 1,338.1</u>
<u>Change in plan assets</u>		
Plan assets at fair value - beginning of year	\$ 806.5	\$ 733.2
Actual return on plan assets	72.6	87.5
Separation of former participants	(32.0)	-
Company contributions	63.8	65.0
Benefits paid	(84.1)	(79.1)
Transfers	(1.9)	(0.1)
Plan assets at fair value - end of year	<u>\$ 824.9</u>	<u>\$ 806.5</u>
<u>Reconciliation of accrued pension cost and total amount recognized</u>		
Funded status of the plan	\$ (517.3)	\$ (531.6)
Unrecognized net loss	435.6	443.6
Unrecognized prior service cost	10.0	9.1
Unrecognized net transition obligation	7.3	15.9
Accrued postretirement benefit before final contribution	(64.4)	(63.0)
Contribution made after measurement date but before March 31	3.7	-
Accrued pension cost	<u>\$ (60.7)</u>	<u>\$ (63.0)</u>
Accrued benefit liability	\$ (342.3)	\$ (383.2)
Intangible asset	17.3	25.0
Accumulated other comprehensive income, pre-tax	6.6	14.5
Regulatory assets	257.7	280.7
Accrued pension cost	<u>\$ (60.7)</u>	<u>\$ (63.0)</u>

The aggregated accumulated benefit obligation was \$1,170.9 million and the fair value of assets was \$828.6 million, measured as of December 31, 2005, and including contributions prior to March 31, 2006.

The Retirement Plan and the SERP currently have assets with a fair value that is less than the accumulated benefit obligation under the Retirement Plan and the SERP, primarily due to prior declines in the equity markets and historically low interest rate levels. As a result, PacifiCorp recognized minimum pension liabilities in the fourth quarters of the years ended March 31, 2006 and 2005. The minimum pension liability adjustment impacted

Regulatory assets, Intangible assets and Accumulated other comprehensive income. These adjustments are reflected in the table above and did not materially affect the consolidated results of operations. PacifiCorp requested and received accounting orders from the regulatory commissions in Utah, Oregon, Wyoming and Washington to classify most of the minimum pension liability adjustment as a Regulatory asset instead of a charge to Other comprehensive income. This increase to Regulatory assets will be adjusted in future periods as the difference between the fair value of the trust assets and the accumulated benefit obligation changes. PacifiCorp has determined that costs related to SFAS No. 87, *Employers' Accounting for Pensions* ("SFAS No. 87") for the Retirement Plan are currently recoverable in rates.

Retirement Plan assets are managed and invested in accordance with all applicable requirements, including the Employee Retirement Income Security Act and the Internal Revenue Code. PacifiCorp employs an investment approach that uses a mix of equities and fixed-income investments to maximize the long-term return of plan assets at a prudent level of risk. Risk tolerance is established through careful consideration of plan liabilities, plan funded status, and corporate financial condition. The investment portfolio contains a diversified blend of equity and fixed-income investments as shown in the table below. Equity investments are diversified across United States and non-United States stocks, as well as growth and value companies, and small and large market capitalizations. Fixed-income investments are diversified across United States and non-United States bonds. Other assets, such as private equity investments, are used to enhance long-term returns while improving portfolio diversification. PacifiCorp primarily minimizes the risk of large losses through diversification but also monitors and manages other aspects of risk through quarterly investment portfolio reviews, annual liability measurements and periodic asset/liability studies.

Details of the Retirement Plan assets by investment category based on market values are as follows:

	Target	March 31,	
		2006	2005
Equity securities	55.0 %	58.5 %	56.1 %
Debt securities	35.0	34.5	33.9
Private equity	10.0	7.0	10.0

Although the SERP had no qualified assets as of March 31, 2006, PacifiCorp has a Rabbi trust that holds corporate-owned life insurance and other investments to provide funding for the future cash requirements of the SERP. Because this plan is nonqualified, the assets in the Rabbi trust are not considered plan assets. The cash surrender value of all of the policies included in the Rabbi trust plus the fair market value of other Rabbi trust investments was \$36.4 million at March 31, 2006 and \$34.7 million at March 31, 2005, net of amounts borrowed against the cash surrender value.

Other Postretirement Benefits

The cost of other postretirement benefits, including health care and life insurance benefits for eligible retirees, is accrued over the active service period of employees. The transition obligation represents the unrecognized prior service cost and is being amortized over a period of 20 years. PacifiCorp funds other postretirement benefits through a combination of funding vehicles. PacifiCorp contributed \$29.7 million for the year ended March 31, 2006; \$24.9 million for the year ended March 31, 2005; and \$25.3 million for the year ended March 31, 2004. The measurement date for plan assets and obligations is December 31 of each year.

For the postretirement benefit plan assets, PacifiCorp employs an investment approach that uses a mix of equities and fixed-income investments to maximize the long-term return of plan assets for a prudent level of risk. Risk tolerance is established through careful consideration of plan liabilities, plan funded status and corporate financial condition. The investment portfolio contains a diversified blend of equity and fixed-income investments. Equity investments are diversified across United States and non-United States stocks, as well as growth and value companies, and small and large market capitalizations. Fixed-income investments are diversified across United States and non-United States bonds. Other assets, such as private equity investments, are used to enhance long-term returns while improving portfolio diversification. PacifiCorp primarily minimizes the risk of large losses through diversification, but also monitors and manages other aspects of risk through quarterly investment portfolio reviews, annual liability measurements and periodic asset/liability studies.

The assets for other postretirement benefits are composed of three different trust accounts. The 401(h) account is invested in the same manner as the pension account. Each of the two Voluntary Employees' Beneficiaries Association Trusts has its own investment allocation strategies. Details of the Voluntary Employees' Beneficiaries Association Trusts' assets by investment category based on market values are as follows:

	Target	March 31,	
		2006	2005
Equity securities	65.0 %	66.0 %	66.4 %
Debt securities	35.0	34.0	33.6

Components of the net periodic postretirement benefit cost are summarized as follows:

(Millions of dollars)	Years Ended March 31,		
	2006	2005	2004
Service cost	\$ 8.8	\$ 8.5	\$ 7.4
Interest cost	30.4	31.0	34.3
Expected return on plan assets (a)	(26.3)	(26.4)	(26.6)
Amortization of unrecognized net transition obligation	12.2	12.2	12.2
Amortization of unrecognized loss	2.7	0.6	0.6
Amortization of prior service cost	2.1	0.1	-
Net periodic postretirement benefit cost	<u>\$ 29.9</u>	<u>\$ 26.0</u>	<u>\$ 27.9</u>

- (a) The market-related value of plan assets, among other factors, is used to determine expected return on plan assets and is calculated by spreading the difference between expected and actual investment returns over a five-year period beginning in the first year in which they occur.

The change in the accumulated postretirement benefit obligation, change in plan assets and funded status of the postretirement plan is as follows:

(Millions of dollars)	March 31,	
	2006	2005
<u>Change in accumulated postretirement benefit obligation</u>		
Accumulated postretirement benefit obligation - beginning of year	\$ 528.3	\$ 555.3
Service cost	8.8	8.5
Interest cost	30.4	31.0
Plan participant contributions	8.3	7.2
Plan amendments	22.8	0.8
Separation of former participants	(8.9)	-
Actuarial loss (gain)	34.3	(34.4)
Benefits paid	(41.6)	(40.1)
Accumulated postretirement benefit obligation - end of year	<u>\$ 582.4</u>	<u>\$ 528.3</u>
<u>Change in plan assets</u>		
Plan assets at fair value - beginning of year	\$ 286.6	\$ 261.6
Actual return on plan assets	20.4	28.6
Company contributions	22.5	29.3
Plan participant contributions	8.3	7.2
Separation of former participants	(4.1)	-
Net benefits paid	(41.6)	(40.1)
Plan assets at fair value - end of year	<u>\$ 292.1</u>	<u>\$ 286.6</u>
<u>Reconciliation of accrued postretirement costs and total amount recognized</u>		
Funded status of the plan	\$ (290.3)	\$ (241.7)
Unrecognized net transition obligation	81.1	94.6
Unrecognized prior service cost	22.1	1.4
Unrecognized loss	138.1	100.1
Accrued postretirement benefit cost, before final contribution	(49.0)	(45.6)
Contribution made after measurement date but before March 31	29.7	24.9
Accrued postretirement cost	<u>\$ (19.3)</u>	<u>\$ (20.7)</u>

The assumed health care cost trend rates are as follows:

	March 31,		
	2006	2005	2004
Initial health care cost trend - under 65	10.0 %	7.5 %	8.5 %
Initial health care cost trend - over 65	10.0	9.5	10.5
Ultimate health care cost trend rate	5.0	5.0	5.0
Year that rate reaches ultimate - under 65	2011	2007	2007
Year that rate reaches ultimate - over 65	2011	2009	2009

The health care cost trend rate assumption has a significant effect on the amounts reported. An annual increase or decrease in the assumed medical care cost trend rate of 1.0% would affect the accumulated postretirement benefit obligation and the service and interest cost components as follows:

(Millions of dollars)	One Percent	
	Increase	Decrease
Accumulated postretirement benefit obligation	\$ 43.7	\$ (35.5)
Service and interest cost components	2.8	(2.4)

Future Contributions and Benefit Payments

In April 2006, PacifiCorp contributed \$72.7 million to its Retirement Plan. In addition, PacifiCorp expects to contribute another \$11.0 million to its pension plans, as well as \$36.6 million to its postretirement benefit plan, during the 12 months ending March 31, 2007. The benefit payments expected to be paid, which reflect expected future service and the Medicare Part D subsidy expected to be received, are as follows:

(Millions of dollars)	Retirement	Other	Medicare
12 months ending March 31.	Plans	Postretirement	Part D
		Benefits	Subsidy
			Receipts
2007	\$ 92.5	\$ 35.8	\$ (3.0)
2008	92.4	37.9	(3.4)
2009	93.6	40.0	(3.9)
2010	94.7	42.1	(4.3)
2011	97.7	44.4	(4.6)
2012 to 2016 (inclusive)	541.2	248.2	(29.9)

Employee Savings Plan

PacifiCorp has an employee savings plan (the "Savings Plan") that qualifies as a tax-deferred arrangement under the Internal Revenue Code. Eligible employees of adopting affiliates are those who are not temporary, casual, leased or covered by a collective bargaining agreement that does not provide for participation. Employees of any company within the PacifiCorp controlled group of companies that has not adopted the Savings Plan are not eligible. Participating United States employees may defer up to 50.0% of their compensation, subject to certain statutory limitations. Compensation includes base pay, overtime and annual incentive, but is limited to the maximum allowable under the Internal Revenue Code. Employees can select a variety of investment options. PacifiCorp matches 50.0% of employee contributions on amounts deferred up to 6.0% of total compensation, with that portion vesting over the initial five years of an employee's qualifying service. Thereafter, PacifiCorp's contributions vest immediately. PacifiCorp's matching contribution is allocated based on the employee's investment selections. PacifiCorp may also make an additional contribution equal to a percentage of the employee's eligible earnings. This additional contribution is allocated based on the employee's investment selections or to the money market fund if the employee has made no selections. These contributions are immediately vested. PacifiCorp's contributions to the Savings Plan were \$22.5 million for the year ended March 31, 2006; \$20.2 million for the year ended March 31, 2005; and \$19.3 million for the year ended March 31, 2004; and represent amounts expensed for such periods.

Severance

As a result of general workforce reductions and ScottishPower's corporate restructuring during the year ended March 31, 2006, PacifiCorp incurred severance expense of \$4.1 million under its severance and other benefit plans related to the involuntary termination of approximately 62 employees. Services provided by these employees are expected to be complete by March 31, 2007.

As a result of the MEHC acquisition, PacifiCorp has experienced organizational changes and additional workforce reductions resulting in severance expense of \$12.9 million during the year ended March 31, 2006 under its severance and other benefit plans, primarily related to the involuntary termination of 29 employees. Additional severance expense is expected to be incurred in the future as additional organizational changes occur.

Note 18 – Stock-Based Compensation

PacifiCorp Stock Incentive Plan (“PSIP”) - During 1997, PacifiCorp adopted the PSIP. The exercise price of options granted under the PSIP was equal to the market value of the common stock on the date of the grant. ScottishPower took control of the plan upon completion of its merger and all stock options were converted into options to purchase ScottishPower American Depositary Shares. The PSIP expired on November 29, 2001 and all outstanding options under the plan were fully vested as of March 31, 2005.

As a result of the sale of PacifiCorp to MEHC and in accordance with the PSIP provisions regarding a change in control, all outstanding options must be exercised no later than 12 months after the date of the sale of PacifiCorp; otherwise they will be forfeited.

ScottishPower Executive Share Option Plan (“ExSOP”) - In prior years, a select group of PacifiCorp employees received grants of stock options under the ScottishPower ExSOP. Certain grants awarded in May 2001 were performance-based awards which resulted in \$2.0 million of compensation expense included in Operations and maintenance expense for the year ended March 31, 2005.

As a result of the sale of PacifiCorp to MEHC on March 21, 2006, all ExSOP options held by PacifiCorp employees became fully vested in accordance with the change-in-control provisions of the ExSOP. The change-in-control provisions also provide that all outstanding options are exercisable up to the later of 12 months after the date of the sale of PacifiCorp or 42 months after the date of original option grant. Options that are not exercised within this time period will be forfeited. As of the date of the sale, PacifiCorp ceased to participate in the plan but as of March 31, 2006, there are still options outstanding and exercisable by PacifiCorp employees.

The table below summarizes the stock option activity under the PSIP and the ExSOP.

	PSIP		ExSOP	
	Number of Shares	Weighted Average Price	Number of Shares	Weighted Average Price
<u>ScottishPower American Depositary Shares</u>				
Outstanding options at March 31, 2003	3,403,251	\$ 31.67	935,054	\$ 23.55
Granted	-	-	780,901	24.40
Exercised	(147,496)	25.55	(25,508)	23.55
Forfeited	(331,706)	34.65	(41,991)	23.93
Outstanding options at March 31, 2004	2,924,049	31.64	1,648,456	23.94
Granted	-	-	763,843	28.72
Exercised	(750,126)	26.10	(483,667)	23.84
Forfeited	(40,310)	35.36	(30,136)	26.37
Outstanding options at March 31, 2005	2,133,613	33.52	1,898,496	25.85
Exercised	(1,325,284)	31.32	(1,404,637)	25.58
Forfeited	(30,578)	35.86	(16,096)	27.59
Transfers due to separation	(68,710)	37.35	(164,677)	25.56
Outstanding options at March 31, 2006	<u>709,041</u>	37.15	<u>313,086</u>	27.15

Information with respect to options outstanding and options exercisable under the PSIP and the ExSOP as of March 31, 2006 and 2005 were as follows:

Range of Exercise Prices	Options Outstanding			Options Exercisable	
	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Life (in years)	Number of Shares	Weighted Average Exercise Price
Year ended March 31, 2006					
PSIP					
\$25.70 - \$36.64	268,205	\$ 31.25	1.0	268,205	\$ 31.25
\$39.99 - \$41.38	440,836	40.74	1.0	440,836	40.74
Total	709,041	37.15	1.0	709,041	37.15
ExSOP					
\$23.55 - \$28.72	313,086	\$ 27.15	1.4	313,086	\$ 27.15
Year ended March 31, 2005					
PSIP					
\$25.70 - \$36.64	1,589,323	\$ 31.05	4.2	1,589,323	\$ 31.05
\$39.99 - \$43.83	544,290	40.72	3.0	544,290	40.72
Total	2,133,613	33.52	3.9	2,133,613	33.52
ExSOP					
\$23.55 - \$28.72	1,898,496	\$ 25.85	8.2	182,134	\$ 23.97

ScottishPower Long-Term Incentive Plan - In prior years, a select group of PacifiCorp employees received grants of performance share awards under ScottishPower's Long-Term Incentive Plan. The number of shares that actually vest is dependent upon the outcome of certain performance measures over a three-year period. The plan's change-in-control provisions resulted in removal of the employees' future service requirement as of the date of the acquisition but retained the three-year performance requirements. As a result, the number of shares that ultimately vest at the end of the performance period, if any, will be prorated to reflect only the portion of the three-year period which had elapsed between the date of original grant and the date of the sale of PacifiCorp to MEHC. During the year ended March 31, 2006, no stock-based compensation expense was recorded because the performance measures were not yet reached.

Deferred Share Program - In May 2004, ScottishPower implemented a deferred share program under which certain PacifiCorp employees were granted an annual stock bonus award based on a fixed dollar amount but distributable in ScottishPower American Depositary Shares with the number of shares to be determined by the quoted market price of the shares at the date of issuance. Historically, compensation expense was accrued throughout the year in which the employee services were rendered and awards earned. During the year ended March 31, 2005, \$3.1 million of compensation costs were accrued. However, as a result of the sale of PacifiCorp to MEHC, the program was modified during the year ended March 31, 2006 to provide for a cash payment rather than a share-based payment. The plan was discontinued as of April 1, 2006.

Note 19 - Income Taxes

The difference between the United States federal statutory tax rate and the effective income tax rate attributed to income from continuing operations is as follows:

	Years Ended March 31,					
	2006		2005		2004	
Federal statutory rate	35.0	%	35.0	%	35.0	%
State taxes, net of federal benefit	2.9		3.8		3.6	
Effect of regulatory treatment of depreciation differences	2.5		4.1		4.5	
Tax reserves	1.1		(0.9)		(3.1)	
Tax credits	(2.6)		(2.3)		(2.5)	
Other	(3.3)		0.4		(0.8)	
Effective income tax rate	35.6	%	40.1	%	36.7	%

The provision for income taxes is summarized as follows:

(Millions of dollars)	Years Ended March 31,		
	2006	2005	2004
Current			
Federal	\$ 167.3	\$ 58.6	\$ 63.0
State	18.2	(10.1)	1.0
Total	185.5	48.5	64.0
Deferred			
Federal	19.7	112.6	77.8
State	2.1	15.3	10.6
Total	21.8	127.9	88.4
Investment tax credits	(7.9)	(7.9)	(7.9)
Total income tax expense	\$ 199.4	\$ 168.5	\$ 144.5

The tax effect of temporary differences giving rise to significant portions of PacifiCorp's deferred tax liabilities and deferred tax assets were as follows:

(Millions of dollars)	March 31,	
	2006	2005
Deferred tax liabilities:		
Property, plant and equipment	\$ 1,531.2	\$ 1,512.3
Regulatory assets	623.0	667.9
Derivative contract regulatory assets	35.9	64.5
Other deferred tax liabilities	114.3	126.3
	<u>2,304.4</u>	<u>2,371.0</u>
Deferred tax assets:		
Regulatory liabilities	(316.9)	(325.2)
Employee benefits	(170.9)	(185.4)
Derivative contracts	(44.0)	(102.6)
Other deferred tax assets	(134.5)	(126.8)
	<u>(666.3)</u>	<u>(740.0)</u>
Net deferred tax liability	<u>\$ 1,638.1</u>	<u>\$ 1,631.0</u>

PacifiCorp made net income tax payments of \$140.0 million for the year ended March 31, 2006; \$92.0 million for the year ended March 31, 2005; and \$114.1 million for the year ended March 31, 2004. The income tax payments include payments for current federal and state income taxes, as well as amounts paid in settlement of prior years' liabilities as a result of income tax proceedings.

PacifiCorp has established, and periodically reviews, an estimated contingent tax reserve on its Consolidated Balance Sheets to provide for the possibility of adverse outcomes in tax proceedings. The net federal and state contingency reserve increased \$6.1 million during the year ended March 31, 2006 primarily due to new issues identified for tax years ended after March 31, 2000. The Internal Revenue Service started its examination of the 2001, 2002 and 2003 tax years in October 2004. PacifiCorp anticipates that final settlement and payment on settled issues and other unresolved issues will not have a material adverse impact on its consolidated financial position or results of operations.

The sale of PacifiCorp to MEHC on March 21, 2006 triggered the recognition of a deferred intercompany gain or loss for tax purposes. The recognition of the tax effects of this item is considered to have been recognized immediately prior to the closing of the sale of PacifiCorp while it was part of the PHI consolidated group. PacifiCorp is currently unable to estimate the amount of the tax effect, if any, or determine a range of the potential tax effect. Due to the uncertainty of the amount of the deferred intercompany gain or loss, no adjustments have been recorded as of March 31, 2006.

Pursuant to a formal agreement with PHI and ScottishPower, any tax liabilities generated as a result of a deferred intercompany gain would be recorded as an equity contribution to PacifiCorp. Additionally, as this transaction is deemed to be with shareholders, the net tax expense would be recorded as a reduction in Common shareholder's capital similar to a return of capital distribution. As a result, there would be no net impact to PacifiCorp's Common shareholder's capital, statement of financial position or results of operations.

If a deferred intercompany loss is determined to exist, PacifiCorp would be required to recognize the tax benefit of the deferred intercompany loss as an increase in Common shareholder's capital and establish a corresponding tax receivable or deferred tax asset, depending on whether PacifiCorp would be able to currently utilize the capital loss. In the event a deferred tax asset is created with respect to the capital loss, it will be necessary to determine whether a valuation allowance should be established against the deferred tax asset.

At March 31, 2006, PacifiCorp had no federal or state net operating loss carryforwards. At March 31, 2005, PacifiCorp had total available federal net operating loss carryforwards of approximately \$2.7 million and no state net operating loss carryforwards. PacifiCorp has Oregon business energy tax credits of approximately \$0.6 million at March 31, 2006 available to reduce future income tax liabilities. These credits begin to expire in 2012. PacifiCorp has Idaho investment tax credits of approximately \$1.9 million at March 31, 2006 that are available to reduce future income tax liabilities. These credits begin to expire in 2017. PacifiCorp anticipates utilizing the tax credits prior to the expiration dates.

Note 20 - Concentration of Customers

During the year ended March 31, 2006, no single retail customer accounted for more than 2.0% of PacifiCorp's retail electric revenues, and the 20 largest retail customers accounted for 13.0% of total retail electric revenues. The geographical distribution of PacifiCorp's retail operating revenues for the year ended March 31, 2006 was: Utah, 40.9%; Oregon, 29.3%; Wyoming, 13.3%; Washington, 8.4%; Idaho, 5.7%; and California, 2.4%.

Note 21 - Subsequent Events

On May 10, 2006, the PacifiCorp Board of Directors determined to change PacifiCorp's fiscal year-end from March 31 to December 31. PacifiCorp's report covering the transition period beginning April 1, 2006 and ending December 31, 2006 will be filed on Form 10-K.

SUPPLEMENTAL INFORMATION

QUARTERLY FINANCIAL DATA (UNAUDITED)

(Millions of dollars, except per share amounts)	Quarters Ended			
	June 30	September 30	December 31	March 31
2006				
Revenues	\$ 881.4	\$ 620.7	\$ 1,165.0	\$ 1,229.6
Income from operations	135.9	129.2	256.2	270.7
Net income	46.4	39.4	127.8	147.1
Earnings on common stock	45.9	38.9	127.2	146.6
Common dividends declared per share	16.3¢	16.3¢	16.3¢	4.8¢
Common dividends paid per share	16.3¢	16.3¢	16.3¢	4.8¢
2005				
Revenues	\$ 747.8	\$ 828.7	\$ 849.5	\$ 622.8
Income from operations	129.9	165.3	155.2	206.0
Net income	50.9	61.9	51.3	87.6
Earnings on common stock	50.4	61.4	50.7	87.1
Common dividends declared per share	15.5¢	15.5¢	15.5¢	15.5¢
Common dividends paid per share	15.5¢	15.5¢	15.5¢	15.5¢

On March 31, 2006, MEHC was the only common shareholder of record.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

No information is required to be reported pursuant to this item.

ITEM 9A. CONTROLS AND PROCEDURES

PacifiCorp maintains disclosure controls and procedures designed to provide reasonable assurance that material information required to be disclosed by it in the reports it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that the information is accumulated and communicated to PacifiCorp's management, including its Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure. PacifiCorp performed an evaluation, under the supervision and with the participation of its management, including its Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of PacifiCorp's disclosure controls and procedures as of the end of the period covered by this report. Based on this evaluation, PacifiCorp's management, including its Chief Executive Officer and Chief Financial Officer, concluded that the disclosure controls and procedures were effective as of the end of the period covered by this report.

On March 21, 2006, MEHC completed its purchase of PacifiCorp, at which time PacifiCorp became a subsidiary of MEHC. Although PacifiCorp has maintained its disclosure controls and procedures that were in effect prior to the acquisition, subsequent to the acquisition there have been material changes in PacifiCorp's internal control over financial reporting. The material changes are due to the effect of the acquisition on PacifiCorp's control environment, which includes changes in the composition of the board of directors, PacifiCorp's organizational structure, audit committee oversight and its corporate governance framework. PacifiCorp believes these changes have not negatively affected its internal control over financial reporting.

During the three months ended March 31, 2006, there was no other change in PacifiCorp's internal control over financial reporting identified in connection with the evaluation required by paragraph (d) of Securities Exchange Act of 1934 Rules 13a-15 or 15d-15 that occurred that has materially affected, or is reasonably likely to materially affect, PacifiCorp's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

No information is required to be reported pursuant to this item.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The following is a list of directors and executive officers of PacifiCorp. There are no family relationships among the executive officers of PacifiCorp. Officers of PacifiCorp are normally elected annually.

<u>Name and Age</u>	<u>Business Experience Past Five Years</u>
Gregory E. Abel (43)	<p>Chief Executive Officer and Chairman. Director since March 2006.</p> <p>Mr. Abel was elected Chief Executive Officer and Chairman of PacifiCorp's Board of Directors in March 2006. Mr. Abel is also the President and Chief Operating Officer and a director of MEHC. Mr. Abel joined MEHC in 1992.</p>
Douglas L. Anderson (48)	<p>Director since March 2006.</p> <p>Mr. Anderson is the Senior Vice President, General Counsel and Corporate Secretary of MEHC. Mr. Anderson joined MEHC in February 1993 and has served in various legal positions, including General Counsel of MEHC's independent power affiliates. Prior to that, Mr. Anderson was a corporate attorney in private practice.</p>
William J. Fehrman (45)	<p>President, PacifiCorp Energy. Director since March 2006.</p> <p>Mr. Fehrman was elected President, PacifiCorp Energy in March 2006 and has responsibility for PacifiCorp's electric generation, commercial and energy trading and coal-mining operations. He joined MEHC in March 2006 to oversee integration activities of MEHC's acquisition of PacifiCorp. Prior to joining MEHC, Mr. Fehrman was President and Chief Executive Officer of Nebraska Public Power District in Columbus, Nebraska. He joined Nebraska Public Power in 1981, serving as its President and Chief Executive Officer since January 2003 and before that as Vice President of Energy Supply.</p>
Brent E. Gale (54)	<p>Director since March 2006.</p> <p>Mr. Gale was appointed Senior Vice President of Regulation and Legislation of MEHC in March 2006. Previously he had been Senior Vice President of MidAmerican Energy Company, a MEHC subsidiary, since July 2004. Mr. Gale has served in various legal, regulatory and strategic positions with MidAmerican Energy Company and its predecessors for more than five years prior to that.</p>
Patrick J. Goodman (39)	<p>Director since March 2006.</p> <p>Mr. Goodman is Senior Vice President and Chief Financial Officer of MEHC. Mr. Goodman joined MEHC in 1995 and has served in various financial positions, including Chief Accounting Officer.</p>

- Andrew P. Haller (54)** Senior Vice President, General Counsel and Corporate Secretary. Director since May 2003.
- Mr. Haller joined PacifiCorp as its Senior Vice President, General Counsel and Corporate Secretary in December 2000 and was also named General Counsel for Pacific Power in March 2006. Prior to joining PacifiCorp, he was chief executive for the United States operations of Kvaerner Process, a position he assumed in 1999. Mr. Haller began his career with Kvaerner in 1987, and held various senior counsel and management positions, including Senior Vice President and General Counsel-Americas. From 1998 to 1999, he served as the Associate General Counsel for the parent company, Kvaerner ASA, in its United States corporate headquarters.
- Nolan E. Karras (61)** Director since February 1993.
- Mr. Karras is President of The Karras Company, Inc., an investment adviser, and has served in that capacity since 1983. He is Chief Executive Officer of Western Hay Company, Inc., a non-executive director of Scottish Power plc and Beneficial Life Insurance Company and is a Registered Principal for Raymond James Financial Services.
- A. Robert Lasich (46)** Vice President and General Counsel, PacifiCorp Energy. Director since March 2006.
- Mr. Lasich joined PacifiCorp and was elected to his current positions in March 2006. Previously he served as Vice President of MEHC with responsibility for integration and transition matters related to the acquisition of PacifiCorp since July 2005. Prior to that, Mr. Lasich was Vice President of Gas Supply and Trading for MidAmerican Energy Company since August 2004. He joined MidAmerican Energy Company in October 1997 and has also served as a senior attorney in its legal department.
- Mark C. Moench (50)** Senior Vice President and General Counsel, Rocky Mountain Power. Director since March 2006.
- Mr. Moench joined PacifiCorp and was elected to his current positions in March 2006. Previously he served as Senior Vice President, Law, of MEHC with responsibility for regulatory approvals of the PacifiCorp acquisition since June 2005. Prior to that, Mr. Moench was Vice President and General Counsel of Kern River Gas Transmission Company since 2002, when Kern River was acquired by MEHC from the Williams Companies, Inc., which he joined in 1987. Mr. Moench served the Williams Companies in various senior legal positions, including as General Counsel of Kern River.
- Richard D. Peach (42)** Senior Vice President and Chief Financial Officer. Director since May 2003.
- Mr. Peach was elected PacifiCorp's Chief Financial Officer effective January 2003 and elected Senior Vice President in March 2006. Mr. Peach had served previously as Senior Vice President of Finance since March 2002. Prior to his appointment as Chief Financial Officer, he also served as Group Controller for Scottish Power plc from March 2000 to December 2002. Head of Customer Services, Energy Supply for ScottishPower from April 1999 to March 2000 and in various other management positions with ScottishPower since 1995.

A. Richard Walje (54)

President, Rocky Mountain Power. Director since July 2001.

Mr. Walje was elected President, Rocky Mountain Power in March 2006 and has responsibility for the electric distribution operations of PacifiCorp in Utah, Idaho and Wyoming. Mr. Walje previously served as PacifiCorp's Executive Vice President since April 2004 and as Chief Information Officer since May 2000. Previously he served as PacifiCorp's Senior Vice President of Corporate Business Services from May 2001 to April 2004 and as PacifiCorp's Vice President for Transmission and Distribution Operations and Customer Service from 1998 to 2000. Mr. Walje has been with PacifiCorp since 1986.

Stanley K. Watters (47)

President, Pacific Power. Director since March 2006.

Mr. Watters was elected President, Pacific Power in March 2006 and has responsibility for the electric distribution operations of PacifiCorp in Oregon, Washington and California. Mr. Watters was elected Senior Vice President of Commercial and Trading in June 2003. Mr. Watters served as Vice President of Trading and Origination from July 2001 to June 2003 and as Managing Director of Wholesale Energy Services since 1998. Mr. Watters has been with PacifiCorp since 1982.

Bruce N. Williams (47)

Treasurer.

Mr. Williams has served as PacifiCorp's Treasurer since February 2000. Prior to being elected Treasurer, he served as Assistant Treasurer of PacifiCorp and has been with PacifiCorp since 1985.

In addition to following MEHC's Code of Business Conduct and Berkshire Hathaway's Code of Business Conduct and Ethics Policy, which provide a basis for employee ethical standards and conduct for all employees, the PacifiCorp Board of Directors previously approved and implemented a "Code of Ethics for Principal Officers" designed to promote the integrity of PacifiCorp's financial reporting and legal compliance. The Code of Ethics for Principal Officers applies to PacifiCorp's Chief Executive Officer and its financial and accounting officers. The Guide to Business Conduct and Code of Ethics for Principal Officers are available in the "About Us - Company Overview" section of PacifiCorp's website at www.pacificorp.com. PacifiCorp intends to make available on its website any amendment to, or waiver from, the Code of Ethics for Principal Officers as the Code applies to PacifiCorp's Chief Executive Officer and its financial and accounting officers.

Through its affiliation with Berkshire Hathaway, PacifiCorp participates in The Network, an independent company that employees and vendors can call to report business conduct issues confidentially and anonymously involving fraud, financial reporting irregularities, misrepresentation of financial reports, non-compliance with internal controls, or suspected illegal or unethical activity.

Because PacifiCorp's common stock is indirectly, wholly owned by MEHC, its Board of Directors consists primarily of internal executives and it is not required to have an audit committee. However, the audit committee of MEHC acts as the audit committee for PacifiCorp.

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ITEM 11. EXECUTIVE COMPENSATION

PACIFICORP BOARD OF DIRECTORS REPORT ON EXECUTIVE COMPENSATION

Introduction

The PacifiCorp Board of Directors submits this report on executive compensation, which outlines the compensation provided to PacifiCorp's executive officers. For most of the year ended March 31, 2006, PacifiCorp was owned by ScottishPower, and this report generally reflects the executive compensation philosophy, practices and programs maintained under ScottishPower ownership. PacifiCorp's acquisition by MEHC on March 21, 2006 generally did not result in material changes to PacifiCorp executive compensation practices, but any such changes are described in this Item 11.

Compensation Committee Interlocks and Insider Participation

Under ScottishPower ownership, the Remuneration Committee of the ScottishPower Board of Directors, assisted by its outside advisors, had the responsibility to approve compensation levels and executive compensation plans for the PacifiCorp Chief Executive Officer, as well as any ScottishPower executive officers serving as PacifiCorp executive officers in a dual capacity, and to review compensation for other executive officers and senior management of PacifiCorp. During the year ended March 31, 2006, the Remuneration Committee was composed entirely of independent, non-executive directors. With the exception of any compensation requiring review by the Remuneration Committee, the Compensation Committee of the PacifiCorp Board of Directors, which under ScottishPower ownership consisted of the PacifiCorp Chief Executive Officer and, at various times during the year ended March 31, 2006, the ScottishPower Chief Executive Officer, the ScottishPower Human Resources Director and PacifiCorp's General Counsel, had responsibility for approving compensation levels and executive compensation plans for executive officers of PacifiCorp. The Remuneration Committee also approved any stock-based compensation to PacifiCorp executive officers, all of which was in the form of ScottishPower equity.

Effective upon MEHC's acquisition of PacifiCorp, PacifiCorp's Board of Directors eliminated its Compensation Committee and delegated its duties to the Chairman of the Board of Directors, Gregory E. Abel. Mr. Abel also serves as PacifiCorp's Chief Executive Officer and as MEHC's President and Chief Operating Officer. He is employed by MEHC and receives no compensation from PacifiCorp or specific compensation from MEHC for his PacifiCorp service; accordingly, references to executive officers in this Item 11 exclude Mr. Abel unless otherwise indicated. The following describes the components of PacifiCorp's executive compensation program and the basis upon which recommendations and determinations were made for the year ended March 31, 2006.

Compensation Philosophy

PacifiCorp's philosophy is that executive compensation should be linked closely to corporate and operational performance, customer service and increases in shareholder value. PacifiCorp's executive compensation program has the following objectives:

- (i) provide competitive total compensation that enables PacifiCorp to attract and retain key executives;
- (ii) provide variable compensation opportunities that are linked to PacifiCorp, operational area, and individual performance; and
- (iii) establish an appropriate balance between incentives focused on short-term objectives and those encouraging sustained performance improvements.

Qualifying compensation for deductibility under Internal Revenue Code Section 162(m) is one of the factors that PacifiCorp considers in designing PacifiCorp's incentive compensation arrangements for executive officers. Internal Revenue Code Section 162(m) limits to \$1.0 million the annual deduction by a publicly held corporation of compensation paid to any executive officer, except with respect to certain forms of incentive compensation that qualify for exclusion. Although it is the intent to design and administer compensation programs that maximize deductibility, PacifiCorp views the objectives outlined above as more important than compliance with the technical requirements necessary to exclude compensation from the deductibility limit of Internal Revenue Code Section

162(m). Nevertheless, with the exception of severance payments made to PacifiCorp's former President and Chief Executive Officer, Judith A. Johansen, PacifiCorp believes that nearly all compensation paid to the executive officers for services rendered in the year ended March 31, 2006, is fully deductible.

Compensation Program Components

During the year ended March 31, 2006, the compensation programs were focused on market-based comparisons on the relevant industry for each executive officer. The electric utility industry was utilized as the exclusive basis for market comparison for positions with a principal focus on electric operations. For positions with a corporate-wide focus, the general industry and electric utility industry were used for market comparison. In all cases, compensation is targeted at market median levels, with an assumption that total compensation greater than market median, in any specific time period, anticipates that PacifiCorp and industry performance exceeds the median performance of peer companies.

PacifiCorp's executive compensation programs have three principal elements: base salaries, annual incentive compensation and long-term incentive compensation, as described below.

Base Salaries

Base salaries and target incentive amounts are reviewed for adjustment at least annually based upon competitive pay levels, individual performance and potential, and changes in duties and responsibilities. Base salary and the target incentive are set at a level such that total annual compensation for satisfactory performance would approximate the median of pay levels in the comparison group used to develop competitive data. In the year ended March 31, 2006, the base salary of each executive officer was increased, based on market analysis, to reflect competitive market changes, individual performance and changes in the responsibilities of some officers.

Annual Incentive Compensation

All PacifiCorp executive officers, including those listed in the Summary Compensation Table other than Mr. Abel, participate in PacifiCorp's Annual Incentive Plan (the "AIP"). In May 2006, PacifiCorp determined that named executive officers are eligible under certain conditions for payments under the AIP in June 2006 as follows: Judith A. Johansen, \$393,751; Andrew P. Haller, \$185,980; A. Richard Walje, \$158,789; Richard D. Peach, \$184,356; Stanley K. Watters, \$131,016; and Matthew Wright, \$142,916.

Long-Term Incentive Compensation

In May 2005, the ScottishPower Remuneration Committee approved grants of performance share awards under ScottishPower's Long-Term Incentive Plan (the "LTIP") for a select group of PacifiCorp executive officers and other senior managers. LTIP awards were also made in April 2004 to certain executive officers and senior managers. The LTIP provides for awards of performance shares that link the rewards closely between management and shareholders and focus on long-term corporate performance. The awards will vest only if the Remuneration Committee is satisfied that certain threshold customer service and financial performance measures are achieved. The number of shares that actually vest depends upon ScottishPower's comparative Total Shareholder Return performance over a three-year performance period. Vested shares are released to participants only after the conclusion of the performance period. In addition to the criteria described above, the vesting of LTIP awards held by PacifiCorp executive officers and senior managers will be prorated to reflect only the portion of the three-year performance period in which PacifiCorp was owned by ScottishPower.

In April 2004, the ScottishPower Remuneration Committee also approved grants of stock options under the ExSOP for certain executive officers and other senior managers, which were awarded in May 2004. These grants were the last stock options awarded under the ExSOP. Upon the closing of PacifiCorp's sale to MEHC, all outstanding ExSOP options vested in full. A number of restricted stock and stock option awards originally made under the PSIP, which was assumed by ScottishPower in connection with its acquisition of PacifiCorp in 1999 and expired in 2001, remain outstanding but are fully vested. Except for the ExSOP grants awarded in May 2004, ExSOP and PSIP awards relate to ScottishPower American Depository Shares or Ordinary Shares and will remain outstanding until March 21, 2007. The ExSOP awards granted in May 2004, will remain outstanding until November 2007.

In May 2004, the ScottishPower Remuneration Committee approved a new program to replace the ExSOP, called the Deferred Share Program, which was part of the AIP for executive officers and senior management. Eligible employees received an increase to their AIP maximum target incentive payment, with the increase paid in ScottishPower American Depositary Shares, for the year ended March 31, 2005. For the year ended March 31, 2006, the Deferred Share Program was modified and potential payments for eligible employees under the program were added to cash payments under the AIP. This program was discontinued as of April 1, 2006.

William Fehrman, President of PacifiCorp Energy, currently participates in MEHC's Long-Term Incentive Partnership Plan. The participation of the other named executive officers (excluding Mr. Abel, who is not a participant) in the plan will be evaluated for PacifiCorp's fiscal year ending December 31, 2007. A copy of the plan is attached as Exhibit 10.71 to the MEHC Annual Report on Form 10-K for the year ended December 31, 2004.

Compensation of Directors

Directors are not paid any fees for serving as directors. All directors are reimbursed for their expenses incurred in attending Board meetings.

Executive Compensation

The following table sets forth information concerning compensation for services in all capacities to PacifiCorp for the years ended March 31, 2006, 2005 and 2004 of the Chief Executive Officer of PacifiCorp, the next four other most highly compensated executive officers of PacifiCorp who were serving as executive officers at the end of the last completed fiscal year and two former PacifiCorp executive officers, either of whom would have been among the four other most highly compensated executive officers if they had been serving in such capacity as of March 31, 2006.

Summary Compensation Table

Name and Principal Position	Year	Annual Compensation (b)		All Other Compensation (e)	Long-Term Compensation			
		Salary (c)	Bonus (d)		Restricted Stock Awards	Securities Underlying Options	LTIP Payout (f)	ScottishPower Performance Shares (g)
Gregory E. Abel (a) Chairman and Chief Executive Officer		-	-	-	-	-	-	-
Judith A. Johansen (h) Former President and Chief Executive Officer	2006	\$ 808,042	\$ 393,751	\$ 4,115,523	-	-	\$ -	15,839
	2005	743,750	437,500	23,311	-	52,228	-	19,916
	2004	589,394	337,500	22,883	-	61,475	-	12,458
Andrew P. Haller Senior Vice President, General Counsel and Corporate Secretary	2006	361,349	185,980	108,955	-	-	-	3,774
	2005	334,480	167,137	20,515	-	11,667	-	4,746
	2004	327,996	190,109	20,165	-	13,530	-	5,484
A. Richard Walje President, Rocky Mountain Power	2006	343,004	158,789	104,409	-	-	-	5,374
	2005	317,307	158,108	20,270	-	16,613	-	6,757
	2004	299,544	127,557	83,173	-	17,751	-	7,195
Richard D. Peach Senior Vice President and Chief Financial Officer	2006	380,456	209,088	248,494	-	-	-	5,704
	2005	210,654	153,987	100,368	-	11,406	-	6,844
	2004	200,291	136,150	115,899	-	10,977	-	6,586
Stanley K. Watters President, Pacific Power	2006	277,671	131,016	88,326	-	-	58,102	2,900
	2005	256,875	128,550	20,100	-	8,965	-	3,647
	2004	243,693	130,728	22,544	-	8,865	-	3,593
Matthew Wright (i) Former Executive Vice President	2006	316,545	142,916	2,028,821	-	-	-	4,959
	2005	292,481	141,945	151,425	-	15,331	-	6,236
	2004	253,612	127,527	62,766	-	10,502	-	6,301
Michael J. Pittman (j) Former Senior Vice President	2006	190,909	268,125	1,839,328	-	-	-	5,490
	2005	323,750	189,000	20,329	-	33,948	-	6,904
	2004	313,125	187,500	20,097	-	38,729	-	7,849

- (a) Mr. Abel receives no compensation from PacifiCorp or specific compensation from MEHC for his PacifiCorp service. Please refer to MEHC's Annual Report on Form 10-K for the year ended December 31, 2005 (File No. 001-14881) for executive compensation information for Mr. Abel.
- (b) May include amounts deferred pursuant to the Compensation Reduction Plan, under which key executives and directors may defer receipt of cash compensation until retirement or a preset future date. Amounts deferred are invested in ScottishPower American Depositary Shares or a cash account on which interest is paid at a rate equal to the Moody's Intermediate Corporate Bond Yield for AA-rated Public Utility Bonds.
- (c) Salary includes foreign housing benefits paid to Mr. Peach and Mr. Wright. The amounts for Mr. Peach were \$8,638 for the year ended March 31, 2006, \$64,944 for the year ended March 31, 2005 and \$68,513 for the year ended March 31, 2004. The amount for Mr. Wright was \$39,380 for the year ended March 31, 2004.
- (d) Bonus includes the value of ScottishPower American Depositary Shares awarded under the AIP Deferred Share Program for the fiscal year ended March 31, 2005.
- (e) Amounts shown for the year ended March 31, 2006, include:

- (i) Company contributions to the PacifiCorp Employee Savings and Stock Ownership Plan (the "Savings Plan") of \$12,850 for Ms. Johansen, \$11,366 for Mr. Haller, \$11,259 for Mr. Walje, \$7,531 for Mr. Peach, \$11,165 for Mr. Watters, \$11,258 for Mr. Wright, and \$7,240 for Mr. Pittman.
- (ii) Portions of premiums on term life insurance policies that PacifiCorp paid in the amounts of \$2,344 for Ms. Johansen, \$1,088 for Mr. Haller, \$1,072 for Mr. Walje, \$1,179 for Mr. Peach, \$836 for Mr. Watters, \$953 for Mr. Wright, and \$513 for Mr. Pittman. These benefits are available to all employees.
- (iii) Annual vehicle allowances of \$9,263 paid to Ms. Johansen, \$9,375 paid to each of Messrs. Haller, Walje, Watters, and Wright, \$4,800 paid to Mr. Peach and \$4,875 paid to Mr. Pittman.
- (iv) Retention payments in the amounts of \$87,126 to Mr. Haller, \$82,703 to Mr. Walje, \$62,500 to Mr. Peach, \$66,950 to Mr. Watters and \$76,323 to Mr. Wright.
- (v) Additional international assignment payments of \$42,195 to Mr. Peach and \$37,868 to Mr. Wright for the year ended March 31, 2006. Also includes international assignee localization payments of \$130,289 to Mr. Peach and \$12,611 to Mr. Wright for the year ended March 31, 2006.
- (vi) Severance benefits, including enhancements related to PacifiCorp's change in control, paid during the year ended, or payable or accrued as of, March 31, 2006, in the amounts of \$4,091,066 to Ms. Johansen, \$1,880,433 to Mr. Wright and \$1,826,700 to Mr. Pittman. Ms. Johansen's and Mr. Wright's amounts include the value of excise tax gross-up payments to be made by PacifiCorp to the Internal Revenue Service on their behalf. ScottishPower reimbursed PacifiCorp for \$1,389,937 of Mr. Pittman's benefits.
- (f) Represents the dollar value of awards under the ScottishPower LTIP that vested and were distributed to the named officer in the form of ScottishPower American Depository Shares.
- (g) Represents the number of ScottishPower American Depository Shares contingently granted in 2006, 2005 and 2004 that can be earned under the terms of the LTIP.
- (h) Ms. Johansen resigned as a PacifiCorp executive officer effective March 21, 2006.
- (i) Mr. Wright resigned as a PacifiCorp executive officer effective March 21, 2006.
- (j) Mr. Pittman resigned as a PacifiCorp executive officer effective September 5, 2005.

Aggregated Option Exercises at March 31, 2006 and Year-End Option Values

The following table sets forth information regarding the aggregate options exercised during the past fiscal year and the option values at March 31, 2006 for each of the named executive officers. All options are for ScottishPower American Depository Shares and include options granted under the PSIP and the ExSOP.

Name	Shares Acquired on Exercise	Value Realized	Number of Securities Underlying Unexercised Options at March 31, 2006		Value of Unexercised In-the-Money Options at March 31, 2006	
			Exercisable	Unexercisable	Exercisable	Unexercisable
Gregory E. Abel	-	\$ -	-	-	\$ -	\$ -
Judith A. Johansen	124,125	1,561,008	-	-	-	-
Andrew P. Haller	19,046	196,042	12,288	-	161,655	-
A. Richard Walje	16,957	282,561	151,359	-	1,274,096	-
Richard D. Peach (a)	41,192	487,765	-	-	-	-
Stanley K. Watters	33,262	364,366	4,350	-	-	-
Matthew Wright (a)	-	-	40,865	-	493,979	-
Michael J. Pittman	217,813	1,933,991	25,520	-	-	-

- (a) Certain options of Mr. Peach and Mr. Wright are for ScottishPower Ordinary Shares, but are presented as American Depository Shares.

Long-Term Incentive Plan Awards in the Last Fiscal Year

The following table sets forth information regarding awards made in the year ended March 31, 2006 to each named executive officer under the LTIP. Each LTIP award entitles the executive officer to acquire, at no cost, the number of ScottishPower American Depositary Shares listed in the table, less any withholding for applicable taxes. An award will only vest if the ScottishPower Remuneration Committee is satisfied that certain performance measures related to the sustained underlying financial performance of the ScottishPower group and improvements in customer service standards are achieved over a period of three years commencing with the fiscal year preceding the date an award is made. The number of shares that vest depend upon ScottishPower's comparative Total Shareholder Return performance over the three-year performance period. Total Shareholder Return performance is measured against a peer group of major international energy companies. No shares vest unless ScottishPower's Total Shareholder Return performance is at least equal to the median performance of the peer group, at which point 40% of the initial award vests. If ScottishPower's performance is equal to or exceeds the top quartile, 100% of the shares vest. The number of shares that vest for performance between these two points is determined on a straight-line basis. Furthermore, the number of vested shares for each award will be prorated to reflect only the portion of the three-year performance period in which PacifiCorp was owned by ScottishPower. Participants may acquire the vested shares at any time after the third anniversary of grant.

Name	Number of Shares, Units or Other Rights	Performance or Other Period Until Maturation or Payout	Estimated Future Payouts Under Non-Stock Price-Based Plans		
			Exercise or Threshold Shares	Target Shares (a)	Maximum Shares (b)
Gregory E. Abel	-	-	-	-	-
Judith A. Johansen	15,839	3 years	-	1,990	4,977
Andrew P. Haller	3,774	3 years	-	474	1,186
A. Richard Walje	5,374	3 years	-	676	1,689
Richard D. Peach	5,704	3 years	-	717	1,792
Stanley K. Waters	2,900	3 years	-	364	911
Matthew Wright	4,959	3 years	-	623	1,558
Michael J. Pittman	5,490	3 years	-	690	1,725

- (a) Amount to vest if threshold measures and median Total Shareholder Return performance are achieved.
(b) Maximum number of shares exercisable reflects prorating related to acquisition by MEHC as described above.

Employment Agreements

In September 2003, Ms. Johansen and PacifiCorp executed an employment agreement providing for a base salary of \$700,000 and a maximum annual incentive award of 75.0% of base salary. Under the agreement, she was eligible for participation in the LTIP, the ExSOP and the Retirement Plan referred to below, in addition to other benefit plans available for senior-level executives of PacifiCorp. Additionally, Ms. Johansen agreed to standard confidentiality, non-competition and non-solicitation terms. In December 2005, Ms. Johansen signed an amendment to her employment agreement with PacifiCorp and ScottishPower. The amendment:

- Provided for the termination of Ms. Johansen's employment with PacifiCorp and her resignation as an officer and director of PacifiCorp and all affiliates, including ScottishPower, effective immediately following the closing of the sale of PacifiCorp to MEHC;
- Restated her waiver of participation in the PacifiCorp Executive Severance Plan;
- Provided for the cash retention award associated with PacifiCorp's sale to MEHC previously approved by ScottishPower's Remuneration Committee, equal to one times base salary, which was contingent on the closing of PacifiCorp's sale to MEHC and also on Ms. Johansen's continued employment and her satisfactory performance of duties in the period through the sale's closing; Ms. Johansen will receive 80.0% of the retention award within 90 days of the closing of the sale and will receive the remaining 20.0% of the award 365 days from the date of the closing, provided there are no claims by MEHC against ScottishPower related to the sale;

- Modified her AIP terms to reflect a single measurement, PacifiCorp's performance against its budget, and to eliminate pro rata payout, as described above;
- Clarified the respective obligations of PacifiCorp and ScottishPower to her after the termination of her employment;
- Provided that upon termination and assuming compliance by her with the terms of her employment agreement, she would receive severance benefits equal to 12 months of salary, bonus and vehicle allowance, plus enhanced change-in-control benefits under the PacifiCorp Supplemental Executive Retirement Plan;
- Provided for a gross-up payment by PacifiCorp to Ms. Johansen to cover any excise tax payable in connection with separation payments, as well as certain health insurance and other benefits following her employment termination; and
- Added certain customary obligations relating to non-disparagement and conflicts of interest.

In December 2004, Mr. Pittman and PacifiCorp executed an employment agreement providing for a base salary of \$325,000 and a maximum annual incentive award of 100.0% of base salary (unless otherwise modified by the Remuneration Committee). Under the agreement, he was eligible for participation in the LTIP, the ExSOP and the Retirement Plan, in addition to other benefit plans available for senior level executives of PacifiCorp. Additionally, Mr. Pittman agreed to standard confidentiality, non-competition and non-solicitation terms.

In October 2005, PacifiCorp entered into a compromise agreement with PHI and Mr. Pittman that superseded Mr. Pittman's employment agreement with PacifiCorp and ScottishPower and documented the terms of his separation from the companies following a ScottishPower corporate restructuring that eliminated his position. Under his employment agreement, Mr. Pittman was entitled to severance benefits equal to 12 months of salary, bonus and vehicle allowance and 6 months of continued health insurance coverage. The Compromise Agreement supplemented those benefits with enhancements generally comparable to those payable under the PacifiCorp Executive Severance Plan for a termination following a change in control of PacifiCorp, including an additional 12 months of salary, bonus and vehicle allowance and health insurance coverage for an additional 18 months. ScottishPower reimbursed PacifiCorp for the cost of the supplemental benefits provided by the compromise agreement.

Mr. Abel's employment agreement with MEHC is described in MEHC's Annual Report on Form 10-K for the year ended December 31, 2005 (File No. 001-14881).

Retention Agreements

In May 2005, PacifiCorp and its Senior Vice President and Chief Financial Officer, Richard D. Peach entered into a retention agreement entitling Mr. Peach to an \$80,000 retention bonus on June 1, 2006 if he remains employed at an acceptable level of performance in PacifiCorp's corporate finance department through May 30, 2006 and has developed a succession and risk mitigation plan for his department. If Mr. Peach's employment is terminated involuntarily due to a workforce reduction during the term of the retention agreement, he will receive the full amount of any unpaid retention bonuses.

In August 2005, PacifiCorp's named executive officers (other than Mr. Abel, Ms. Johansen and Mr. Pittman) entered into agreements with ScottishPower for awards under the Transaction Incentive Program, which is a \$6.0 million pool created by ScottishPower for retention incentives during the period of completion of ScottishPower's sale of PacifiCorp to MEHC. The agreement signed by each named executive officer provided for a transaction incentive award in an amount equal to the executive officer's base salary (in Mr. Peach's case, this amount was adjusted for his existing retention agreement), payable as follows:

- 25.0% of the award was paid within one month of execution and delivery of the award agreement;
- 50.0% of the award is payable three months after the closing of PacifiCorp's sale to MEHC, provided there are no claims by MEHC against ScottishPower; and
- 25.0% of the award is payable 12 months after the closing, again as long as there are no claims by MEHC against ScottishPower.

Continued employment by PacifiCorp, observance of confidentiality obligations and satisfactory performance in support of the transaction until the sale's completion are conditions to the executive officer's receipt of these payments. Award payments are the obligation of ScottishPower. Ultimate determinations of award eligibility will be made by ScottishPower's Chief Executive Officer, subject to review by its Remuneration Committee.

On May 24, 2006, PacifiCorp entered into certain retention agreements with each of Messrs. Haller and Peach. Under each retention agreement, provided that the executive has not voluntarily resigned or had his employment with PacifiCorp terminated for cause prior to December 31, 2006 for Mr. Haller and November 22, 2006 for Mr. Peach, the executive (i) will be entitled to the same benefits the executive would have been entitled to under PacifiCorp's Supplemental Executive Retirement Plan ("SERP") had the executive terminated his employment during the two-month window period following the first anniversary of a change in control, and (ii) will be entitled, upon any termination on or following the applicable retention date, to the same benefits the executive would have been entitled to under PacifiCorp's Executive Severance Plan had such termination occurred in connection with a material alteration in position or compensation within the 24-month period following a change in control.

Severance Arrangements

PacifiCorp's Executive Severance Plan provides severance benefits to certain executive-level employees who in the past were designated by the PacifiCorp Compensation Committee, but who in the future will be designated by the Chairman of the Board of Directors. The executive officers named in the Summary Compensation Table (other than Mr. Abel and Ms. Johansen) participate in this plan.

Severance benefits are payable by PacifiCorp for voluntary terminations as a result of a certain material alterations in position or compensation that have a detrimental impact on the executive's employment or involuntary terminations (including a PacifiCorp-initiated resignation) for reasons other than cause. Severance payments generally equal one or two times the executive's annual cash compensation, three months of health insurance benefits and outplacement services.

The Executive Severance Plan also provides enhanced severance benefits in the event of certain terminations during the 24-month period following a qualifying change-in-control transaction; with respect to MEHC's acquisition of PacifiCorp, this qualifying period commenced on May 23, 2005. Executives designated by the PacifiCorp Compensation Committee or Chairman, as applicable, are eligible for change-in-control benefits resulting from either a PacifiCorp-initiated termination without cause or a resignation generally within two months after certain material alterations in position or compensation. If qualified for the enhanced severance benefits, an executive would receive severance pay in an amount equal to either two, two and one-half or three times the annual cash compensation of the executive, depending on the level set by the PacifiCorp Compensation Committee or Chairman, as applicable. PacifiCorp is required to make an additional payment to compensate the executive for the effect of any excise tax. The executive would also receive continuation of subsidized health insurance from six to 24 months, depending on length of service, and outplacement services.

Retirement Plans

PacifiCorp has adopted non-contributory defined benefit retirement plans for its employees, other than employees subject to collective bargaining agreements that do not provide for coverage. Certain executive officers, including the executive officers named in the Summary Compensation Table other than Mr. Abel, are also eligible to participate in PacifiCorp's non-qualified SERP. The following description assumes participation in both the Retirement Plan and the SERP. Participants receive benefits at retirement payable for life based on length of service with PacifiCorp and average pay in the 60 consecutive months of highest pay out of the last 120 months, and pay for this purpose would include salary and AIP payments reflected in the Summary Compensation Table above. Benefits are based on 50.0% of final average pay plus 1.0% of final average pay for each year that PacifiCorp meets certain performance goals set for each fiscal year by, in the past, the PacifiCorp Compensation Committee, and now the Chairman of the Board of Directors. The maximum benefit is 65.0% of final average pay. Participants may also elect actuarially equivalent alternative forms of benefits. Retirement benefits are adjusted to reflect social security benefits as well as certain prior employer retirement benefits. Participants are entitled to receive full benefits upon retirement

after age 60 with at least 15 years of service. Participants are also entitled to receive reduced benefits upon early retirement after age 55 or after age 50 with at least 15 years of service and five years of participation in the SERP.

The following table shows the estimated annual retirement benefit payable upon retirement at age 60 as of March 31, 2006. Amounts in the table reflect payments from the Retirement Plan and the SERP combined, prior to any offset of projected social security benefits and benefits paid from any prior employer plan.

Estimated Annual Pension at Retirement (a)

Final Average Pay at Retirement Date	Years of Service (b)			
	5	15	25	30
\$ 200,000	\$ 43,333	\$ 130,000	\$ 130,000	\$ 130,000
400,000	86,667	260,000	260,000	260,000
600,000	130,000	390,000	390,000	390,000
800,000	173,333	520,000	520,000	520,000
1,000,000	216,667	650,000	650,000	650,000

- (a) The benefits shown in this table assume that the individual will remain in the employ of PacifiCorp until retirement at age 60, that the Retirement Plan and the SERP will continue in their present form and that PacifiCorp achieves its performance goals under the SERP in all years.
- (b) The number of credited years of service used to compute aggregate benefits under the Retirement Plan and the SERP are five for Ms. Johansen, five for Mr. Haller, 20 for Mr. Walje, 11 for Mr. Peach, 24 for Mr. Watters, 19 for Mr. Wright and 26 for Mr. Pittman.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

All outstanding shares of common stock of PacifiCorp are indirectly owned by MEHC, 666 Grand Avenue, Des Moines, Iowa 50309. MEHC is a consolidated subsidiary of Berkshire Hathaway, which owns approximately 88.2% of MEHC's common stock (86.6% on a diluted basis). The balance of MEHC's common stock is owned by a private investor group comprised of Walter Scott, Jr. (including family members and related entities), David L. Sokol and Gregory E. Abel, PacifiCorp's Chairman and Chief Executive Officer.

Based on a Schedule 13G filed with the SEC on February 15, 2006, CAM North America, LLC, 399 Park Avenue, New York, NY 10022, is the beneficial owner of 38,910 shares, or 5.19%, of PacifiCorp's outstanding 7.48% Series Preferred Stock.

No PacifiCorp executive officers or directors own shares of PacifiCorp's preferred stock or shares of the Class B common stock of Berkshire Hathaway. The following table sets forth certain information as of March 31, 2006 regarding the beneficial ownership of common stock of MEHC and the Class A common stock of Berkshire Hathaway by (i) each of the executive officers named in the Summary Compensation Table under Item 11. Executive Compensation above, (ii) each director of PacifiCorp as detailed under "Item 10. Directors and Executive Officers of the Registrant," and (iii) all executive officers and directors of PacifiCorp as a group.

Beneficial Owner	MidAmerican Common Stock		Berkshire Hathaway Class A Common Stock	
	Number of shares Beneficially Owned (a)	Percentage of Class (a)	Number of shares Beneficially Owned (a)	Percentage of Class (a)(c)
Gregory E. Abel (b)	749,992	1.01 %	-	- %
Douglas L. Anderson	-	-	3	*
William J. Fehrman	-	-	-	-
Brent E. Gale	-	-	-	-
Patrick J. Goodman	-	-	2	*
Andrew P. Haller	-	-	-	-
Nolan E. Karras	-	-	-	-
A. Robert Lasich	-	-	-	-
Mark C. Moench	-	-	1	*
Richard D. Peach	-	-	-	-
A. Richard Walje	-	-	-	-
Stanley K. Watters	-	-	-	-
Bruce N. Williams	-	-	-	-
All executive officers and directors as a group (13 persons)	749,992	1.01 %	6	*

- (a) Includes shares as to which the listed beneficial owner is deemed to have the right to acquire beneficial ownership under Rule 13d-3(d) under the Securities Exchange Act, including, among other things, shares which the listed beneficial owner has the right to acquire within 60 days.
- (b) Includes options to purchase 649,052 shares of common stock which are exercisable within 60 days. Excludes 10,041 shares reserved for issuance pursuant to a deferred compensation plan.
- (c) * Indicates beneficial ownership of less than one percent of all outstanding shares.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS RELATED TRANSACTIONS

According to the terms of Andrew P. Haller's offer letter, PacifiCorp made a \$200,000.00 loan to Mr. Haller on May 21, 2001 for the repayment of obligations to his former employer. The loan accrues interest at the annual rate of 4.74%. Mr. Haller has repaid \$146,793.50 of the loan amount. The largest outstanding loan balance, including accrued interest, at any time during the year ended March 31, 2006 was \$86,206.50 at July 11, 2005. As of March 31, 2006, the outstanding loan balance was \$55,016.83, including accrued interest. The remaining balance and interest is payable in one payment of \$32,988.56 on June 30, 2006 and one payment of \$23,730.98 on June 30, 2007.

See "Item 8. Financial Statements and Supplementary Data – Note 4 – Related-Party Transactions" for other information on related-party transactions.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The ScottishPower Audit Committee retained PricewaterhouseCoopers LLP, independent certified public accountants, as PacifiCorp's independent registered public accounting firm for the year ended March 31, 2006, which was affirmed by the MEHC Audit Committee.

Fees and Pre-Approval Policy

MEHC's Audit Committee has an Audit and Non-Audit Services Pre-Approval Policy (the "Policy") which sets forth the procedures and the conditions pursuant to which services to be performed by the independent registered public accountant are to be pre-approved. Pursuant to the Policy, certain services described in detail in the Policy may be pre-approved on an annual basis together with pre-approved maximum fee levels for such services. The services eligible for annual pre-approval consist of services that would be included under the categories of Audit fees, Audit-related fees and Tax fees below. If not pre-approved on an annual basis, proposed services must otherwise be

separately approved prior to being performed by the independent registered public accountant. In addition, any services that receive annual pre-approval but exceed the pre-approved maximum fee level also will require separate approval by the Audit Committee prior to being performed. The PacifiCorp Board of Directors has not adopted any pre-approval policy that is in addition to or different than the MEHC Audit Committee's pre-approval policy.

ScottishPower's Audit Committee used a pre-approval policy for PricewaterhouseCoopers' services and fees. This policy detailed the services that could be provided by the independent registered public accounting firm, and required that where the initial fee value for any services permitted in accordance with the policy exceeded £100,000 (or its United States dollar equivalent), the assignment had to be reviewed and authorized by the Chairman of the ScottishPower Audit Committee with the concurrence of the ScottishPower Finance Director. Any services authorized by the Chairman were reported to the ScottishPower Audit Committee at its next scheduled meeting, and fees paid to the independent registered public accounting firm were reported regularly to the ScottishPower Audit Committee.

The following table presents fees billed by PricewaterhouseCoopers for the years ended March 31, 2006 and 2005.

(Millions of dollars)

	Year Ended March 31,			
	2006		2005	
Audit fees	\$ 1.4	42.4 %	\$ 1.4	30.4 %
Audit-related fees	0.4	12.2	1.1	23.9
Tax fees	1.4	42.4	2.0	43.5
Other fees	0.1	3.0	0.1	2.2
Total	<u>\$ 3.3</u>	<u>100.0 %</u>	<u>\$ 4.6</u>	<u>100.0 %</u>

Audit fees are for the audit and review of PacifiCorp's financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States), including comfort letters, statutory and regulatory audits, consents and services related to SEC matters.

Audit-related fees are for assurance and related services that are related to the audit or review of PacifiCorp's financial statements, including employee benefit plan audits, due diligence services and financial accounting and reporting consultation.

Tax fees are fees for tax compliance services and related costs.

Other fees are mainly for services rendered in connection with requests from state regulatory commissions and for regulatory matters.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

- (a) 1. The list of all financial statements filed as a part of this report is included in Item 8. Financial Statements and Supplementary Data.
2. Schedules:*
- * All schedules have been omitted because of the absence of the conditions under which they are required or because the required information is included elsewhere in the financial statements included under "Item 8. Financial Statements and Supplementary Data."

3. Exhibits:

Exhibit

Number

Exhibit Title

- 2.1(a)* Agreement and Plan of Merger, dated as of December 6, 1998, by and among Scottish Power plc, NA General Partnership, Scottish Power NA 1 Limited and Scottish Power NA 2 Limited. (Exhibit 1 to the Form 6-K, dated December 11, 1998, filed by Scottish Power plc, File No. 1-14676).
- 2.1(b)* Amended and Restated Agreement and Plan of Merger, dated as of December 6, 1998, as amended as of January 29, 1999 and February 9, 1999, and amended and restated as of February 23, 1999, by and among New Scottish Power PLC, Scottish Power plc, NA General Partnership and PacifiCorp (Exhibit (2)b, Form 10-K for year ended December 31, 1998, File No. 1-5152).
- 3.1* Third Restated Articles of Incorporation of PacifiCorp (Exhibit (3)b, Form 10-K for the year ended December 31, 1996, File No. 1-5152).
- 3.2 Bylaws of PacifiCorp, as amended May 23, 2005.
- 4.1* Mortgage and Deed of Trust dated as of January 9, 1989, between PacifiCorp and JP Morgan Chase Bank (formerly known as The Chase Manhattan Bank), Trustee, Ex. 4-E, Form 8-B, File No. 1-5152, as supplemented and modified by 18 Supplemental Indentures as follows:

<u>Exhibit</u>	<u>File Type</u>	<u>File Date</u>	<u>File</u>
<u>Number</u>			<u>Number</u>
(4)(b)			33-31861
(4)(a)	8-K	January 9, 1990	1-5152
4(a)	8-K	September 11, 1991	1-5152
4(a)	8-K	January 7, 1992	1-5152
4(a)	10-Q	Quarter ended March 31, 1992	1-5152
4(a)	10-Q	Quarter ended September 30, 1992	1-5152
4(a)	8-K	April 1, 1993	1-5152
4(a)	10-Q	Quarter ended September 30, 1993	1-5152
(4)b	10-Q	Quarter ended June 30, 1994	1-5152
(4)b	10-K	Year ended December 31, 1994	1-5152
(4)b	10-K	Year ended December 31, 1995	1-5152
(4)b	10-K	Year ended December 31, 1996	1-5152
4(b)	10-K	Year ended December 31, 1998	1-5152
99(a)	8-K	November 21, 2001	1-5152
4.1	10-Q	Quarter ended June 30, 2003	1-5152
99	8-K	September 8, 2003	1-5152
4	8-K	August 24, 2004	1-5152
4	8-K	June 13, 2005	1-5152

- 4.2* Third Restated Articles of Incorporation and Bylaws. See 3.1 and 3.2 above.

In reliance upon item 601(4)(iii) of Regulation S-K, various instruments defining the rights of holders of long-term debt of the Registrant and its subsidiaries are not being filed because the total amount authorized under each such instrument does not exceed 10.0% of the total assets of the Registrant and its subsidiaries on a consolidated basis. The Registrant hereby agrees to furnish a copy of any such instrument to the Commission upon request.

- 10.1* Judith Johansen Employment Agreement (Exhibit 10.3, Annual Report on Form 10-K, filed May 27, 2005, File No. 1-5152).
- 10.2* Amendment No. 1 to Employment Agreement among PacifiCorp, Scottish Power plc and Judith Johansen, dated as of December 20, 2005 (Exhibit 10, Current Report on Form 8-K, filed December 23, 2005, File No. 1-5152).
- 10.3* Compensation Reduction Plan (Exhibit 10.5, Annual Report on Form 10-K, filed May 27, 2005, File No. 1-5152).
- 10.4* Amendment No. 1 to PacifiCorp Compensation Reduction Plan, dated effective July 1, 2003 (Exhibit 10.2, Quarterly Report on Form 10-Q, filed November 10, 2005, File No. 1-5152).
- 10.5* Amendment No. 2 to PacifiCorp Compensation Reduction Plan, dated effective September 20, 2005 (Exhibit 10.3, Quarterly Report on Form 10-Q, filed November 10, 2005, File No. 1-5152).
- 10.6* Executive Severance Plan (Exhibit 10.3, Current Report on Form 8-K, filed May 6, 2005, File No. 1-5152).
- 10.7* Amendment to PacifiCorp Executive Severance Plan, dated effective October 31, 2005. (Exhibit 10.2, Quarterly Report on Form 10-Q, filed February 14, 2006, File No. 1-5152).
- 10.8* Supplemental Executive Retirement Plan (Exhibit 10.7, Annual Report on Form 10-K, filed May 27, 2005, File No. 1-5152).
- 10.9* Richard Peach Retention Agreement (Exhibit 10.4, Current Report on Form 8-K, filed May 6, 2005, File No. 1-5152).
- 10.10* Andrew Haller Promissory Note (Exhibit 10.11, Annual Report on Form 10-K, filed May 27, 2005, File No. 1-5152).
- 10.11* Form of Transaction Incentive Program Award Agreement for Named Executive Officers (Exhibit 10, Current Report on Form 8-K, filed September 1, 2005, File No. 1-5152).
- 10.12* Michael Pittman Employment Agreement (Exhibit 10.4, Annual Report on Form 10-K, filed May 27, 2005, File No. 1-5152).
- 10.13* Compromise Agreement among PacifiCorp, PacifiCorp Holdings, Inc. and Michael J. Pittman, dated October 4, 2005 (Exhibit 10.4, Quarterly Report on Form 10-Q, filed November 10, 2005, File No. 1-5152).
- 10.14 Andrew Haller Retention Agreement.
- 10.15 Richard Peach Retention Agreement.
- 12.1 Statements of Computation of Ratio of Earnings to Fixed Charges.
- 12.2 Statements of Computation of Ratio of Earnings to Combined Fixed Charges and Preferred Stock

Dividends.

- 23 Consent of PricewaterhouseCoopers LLP.
- 24 Power of Attorney.
- 31.1 Section 302 Certification of Principal Executive Officer Pursuant to Rule 13a-14(a)/15d-14(a).
- 31.2 Section 302 Certification of Principal Financial Officer Pursuant to Rule 13a-14(a)/15d-14(a).
- 32.1 Section 906 Certification of Principal Executive Officer Pursuant to 18 U.S.C. Section 1350.
- 32.2 Section 906 Certification of Principal Financial Officer Pursuant to 18 U.S.C. Section 1350.
- 99.1* Stock Purchase Agreement among Scottish Power plc, PacifiCorp Holdings, Inc. and MidAmerican Energy Holdings Company (Exhibit 99.1, Current Report on Form 8-K, filed May 24, 2005, by MidAmerican Energy Holdings Company, File No. 001-14881).
- 99.2* Amendment No. 1 to Stock Purchase Agreement, dated as of March 21, 2006, by and among Scottish Power plc, PacifiCorp Holdings, Inc. and PPW Holdings LLC (as successor-in-interest to MidAmerican Energy Holdings Company) (Exhibit 10.1, Current Report on Form 8-K, filed March 21, 2006, by MidAmerican Energy Holdings Company, File No. 001-14881).

*Incorporated herein by reference.

- (b) See (a) 3. above.
- (c) See (a) 2. above.

PURSUANT TO THE REQUIREMENTS OF SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934, THE REGISTRANT HAS DULY CAUSED THIS REPORT TO BE SIGNED ON ITS BEHALF BY THE UNDERSIGNED THEREUNTO DULY AUTHORIZED.

By: /s/ GREGORY E. ABEL
Gregory E. Abel
(CHIEF EXECUTIVE OFFICER)

PURSUANT TO THE REQUIREMENTS OF THE SECURITIES EXCHANGE ACT OF 1934, THIS REPORT HAS BEEN SIGNED BELOW BY THE FOLLOWING PERSONS ON BEHALF OF THE REGISTRANT AND IN THE CAPACITIES AND ON THE DATES INDICATED.

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 * A. ROBERT LASICH

 A. Robert Lasich
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 * MARK C. MOENCH

 Mark C. Moench
) Director
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 * A. RICHARD WALJE

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May 26, 2006

*By: /s/ RICHARD D. PEACH

 Richard D. Peach, as
 Attorney-in-Fact

EUGENE WATER & ELECTRIC BOARD
INDEPENDENT AUDITOR'S REPORTS AND
FINANCIAL STATEMENTS
DECEMBER 31, 2005

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EUGENE WATER & ELECTRIC BOARD
DECEMBER 31, 2005

BOARD OF COMMISSIONERS
500 East Fourth Avenue ▪ Eugene, Oregon 97401

Mr. Ron Farmer	President
Ms. Sandra Bishop	Vice-President
Mr. Patrick Lanning	Member
Mr. John Simpson	Member
Mr. Mel Menegat	Member

OFFICERS
500 East Fourth Avenue ▪ Eugene, Oregon 97401

Mr. Randy L. Berggren	General Manager, Secretary
Ms. Krista K. Hince	Assistant Secretary
Mr. James H. Origliosso	Treasurer
Ms. Catherine D. Bloom	Assistant Treasurer

INDEPENDENT AUDITOR'S REPORT

To the Board of Commissioners
Eugene Water & Electric Board

We have audited the accompanying balance sheets of the Electric System and Water System of Eugene Water and Electric Board ("Board") as of December 31, 2005 and the related statements of revenues, expenses and changes in fund net assets and cash flows for the year then ended. These financial statements are the responsibility of the Board's management. Our responsibility is to express an opinion on these financial statements based on our audit.

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

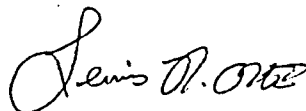
In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Board as of December 31, 2005 and the results of its operations and its cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America.

The management's discussion and analysis preceding the financial statements is not a required part of the basic financial statements but is supplementary information required by the Governmental Accounting Standards Board. We have applied certain limited procedures, which consisted principally of inquiries of management regarding the methods of measurement and presentation of the required supplementary information. However, we did not audit the information and express no opinion on it.

Our audit was conducted for the purpose of forming an opinion on the basic financial statements taken as a whole. The financial information included as supplementary information following the financial statements and notes to financial statements is provided for purposes of additional analysis and is not a required part of the basic financial statements. Such information has been subjected to the auditing procedures applied in the audit of the financial statements and, in our opinion, is fairly stated in all material respects in relation to the financial statements taken as a whole.

Moss Adams LLP

Vancouver, Washington
January 26, 2006



A Partner of Moss Adams LLP
Certified Public Accountants

EUGENE WATER & ELECTRIC BOARD MANAGEMENT'S DISCUSSION AND ANALYSIS

The Eugene Water & Electric Board ("Board" or "EWEB") is an administrative unit of the City of Eugene, Oregon ("City") and is responsible for the operation of the water and electric utilities of the City. The responsibilities delegated to the Board pursuant to the City Charter are conducted under the direction of a publicly elected board of five commissioners. The Board operates vertically integrated electric and water utilities that serve 84,200 electric customers and 49,200 water customers.

Financial Policies and Controls

The Board's financial management system consists of financial policies, financial management strategies, and the internal control structure, including the annual budgets and external audit of its financial statements. The Board has the exclusive right to determine rates and charges for services provided. The Board has established standards for financial performance and rate competitiveness that place its financial performance above the average of publicly owned electric and water utilities. This objective is reflected in evaluations of creditworthiness performed by the major credit rating agencies. Current underlying ratings are:

	<u>Fitch</u>	<u>Moody's</u>	<u>Standard & Poors</u>
Electric System	A+	A1	AA-
Water System	AA	Aa3	AA

Power Supply Risk Management Policies

The Board must comply with State statutes and City Charter that authorize and control its activities and the scope of its purchases and investments. Accordingly, EWEB's activities in the power markets must be associated with the provision of electricity to meet anticipated sales and generation forecasts. To ensure this requirement is met, Board policies restrict the maximum long and short positions that can be taken relative to forward forecasts. The Board may grant exception to this policy to deal with specific circumstances, such as long-term resource acquisitions.

In addition to these anti-speculation provisions, the policies set standards for power supply counterparty creditworthiness. Credit exposure to all existing and potential counterparties is reviewed on a continuous basis and actions are taken to either obtain security or restrict business transactions so as to be consistent with the credit evaluation.

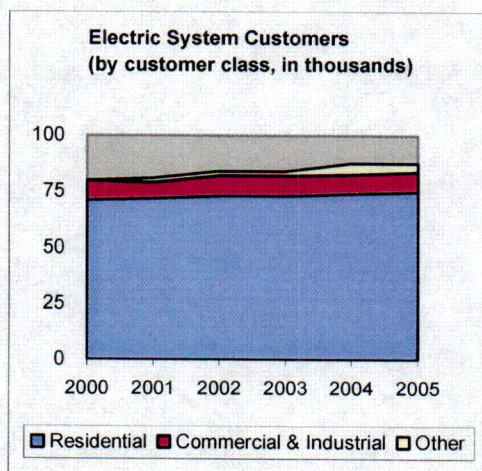
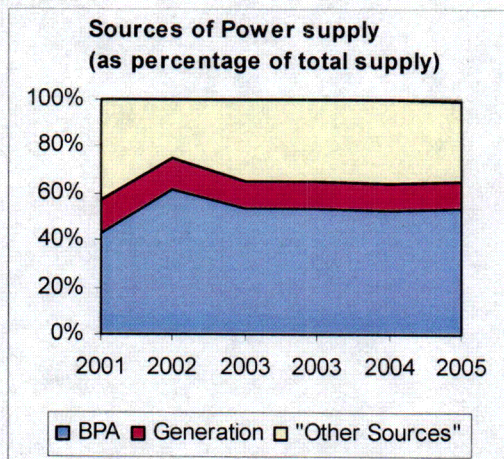
Electric System

The Electric System serves a 238-square mile area, including the City and adjacent suburban areas. Power supply requirements are met primarily from hydroelectric sources, including self-generation and purchases from Bonneville Power Administration ("BPA"). Heating load and general economic conditions are the primary influences on retail sales. However, overall financial condition is influenced to a much greater degree by the availability of water for generation that is in excess of historically critical conditions both locally and regionally.

EUGENE WATER & ELECTRIC BOARD MANAGEMENT'S DISCUSSION AND ANALYSIS

The Electric System in 2005 purchased 56% of its power used to serve load from BPA, the majority of which is provided under a "Slice of System" contract with the remainder obtained under a standard output ("Block") contract. Under the Slice agreement EWEB has rights to 2.4% of the output of the federal BPA system. At critical water conditions this portion of output, together with EWEB's self-generation is sufficient to serve retail load. The price of Slice power is set assuming critical water conditions. To the extent water conditions are above critical, the resulting secondary output is obtained at no additional charge. Sales prices are supported by output sales into forward markets and by financial instruments that have the effect of setting minimum price for sales of secondary power.

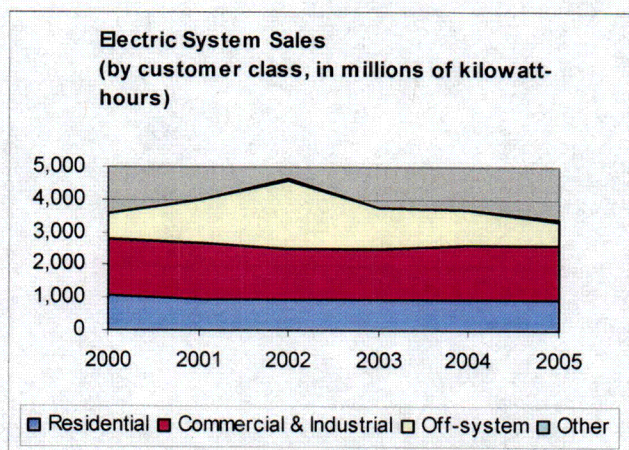
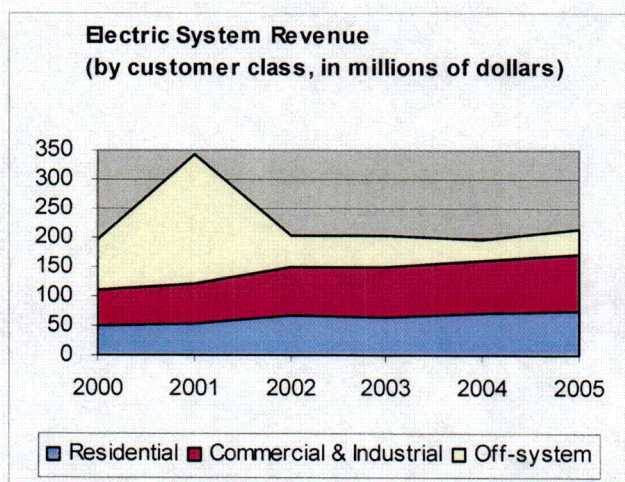
Beginning in 2005, EWEB changed its budgeting and forecasting process to assume that available water for generation is 85% of the normal precipitation.



EUGENE WATER & ELECTRIC BOARD MANAGEMENT'S DISCUSSION AND ANALYSIS

Financial Summary and Analysis

During 2005 the Electric System's gross operating revenues increased by \$7 million (or 3.3%). Retail revenues increased by \$9 million (5.5%) in comparison to 2004. The increase was as a result of the full year impact of the two retail rate increases in 2004 (4.6 % in April and 5.7 % in October) offset by two rate decreases in 2005 of 1.6% in May and 2.5% in November. The 2005 rate decreases were the result of reductions in Bonneville wholesale rates that were in turn, passed through to the customers. As a result, net operating revenue increased \$4 million (9.6%) over 2004.



**EUGENE WATER & ELECTRIC BOARD
MANAGEMENT'S DISCUSSION AND ANALYSIS**

Selected Financial Data

(in millions of dollars)

	2005	2004
Operating revenues	\$ 218	\$ 211
Operating expenses	175	171
Net operating income	44	40
Other revenues	5	4
Other expenses	(30)	(25)
Income before contributed capital	19	19
Contributed capital	3	3
Change in net assets	\$ 22	\$ 22
 Total assets	 \$ 433	 \$ 396
 Total liabilities	 \$ 269	 \$ 254
Net assets		
Invested in capital assets, net of related debt	94	73
Restricted	10	9
Unrestricted	60	60
Total net assets	164	142
Total liabilities and net assets	\$ 433	\$ 396

Capital Asset and Long-Term Debt Activity

Total utility plant in service as of December 31, 2005 and 2004 consisted of the following:

(in millions of dollars)

	2005	2004
Generation and land	\$ 174	\$ 169
Transmission and distribution	225	218
General plant	73	67
 Total plant in service	 \$ 472	 \$ 454

As of year end, the Electric System had \$472 million of plant-in-service. Additions to electric plant consisted primarily of re-licensing related improvements to the Leaburg Hydroelectric Project and the distribution system. Utility plant in service, net of accumulated depreciation, was \$221 million. This represented an increase of \$9 million (4.4%) over 2004. Capital construction is provided for through a combination of construction fees, cash flow from revenues and long-term revenue bonds.

EUGENE WATER & ELECTRIC BOARD MANAGEMENT'S DISCUSSION AND ANALYSIS

Total liabilities as of December 31, 2005 and 2004 consisted of the following:

(in millions of dollars)

	2005	2004
Current liabilities	\$ 50	\$ 42
Noncurrent liabilities	219	212
Total liabilities	<u>\$ 269</u>	<u>\$ 254</u>

EWEB issues revenue bonds to provide for the construction of capital facilities. At year end, the Electric System had \$214 million of revenue bonds outstanding versus \$210 million last year. Additional bonds were issued during 2005 in the amount of \$10.5 million to perform studies to support the Carmen-Smith Hydroelectric Plant relicensing application and to perform preliminary design of a new headquarters facility.

Economic Factors, Rates, and Outlook

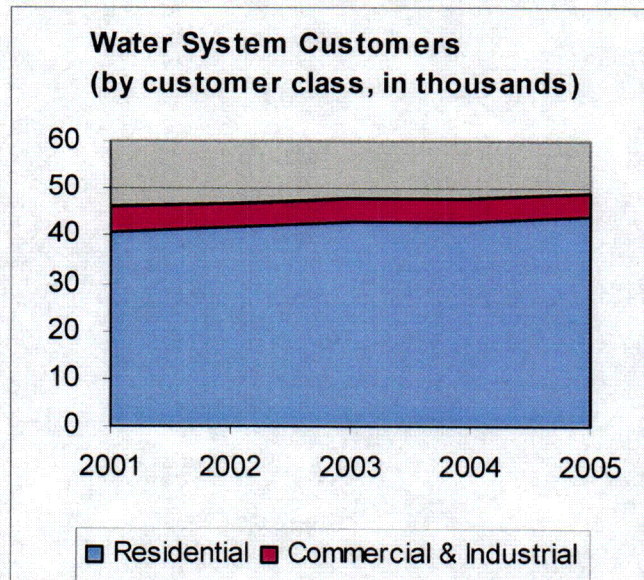
During 2006 retail electric rates are expected to change so as to pass through the effects of Bonneville wholesale rate changes, additional debt service requirements, and an additional increment of renewable energy resources. EWEB expects to issue up to \$4.5 million in Electric Revenue Bonds during 2006 to complete the application process.

The Federal Energy Regulatory Commission license to operate the Carmen Smith Hydroelectric Project expires in 2008. Continued operation of the project requires the submission of an extensive license application requiring substantial scientific study and consultation with environmental and regulatory agencies. The application is due to be submitted in 2006. The level of capital improvements to be required by the new license cannot be determined at this time.

Water System

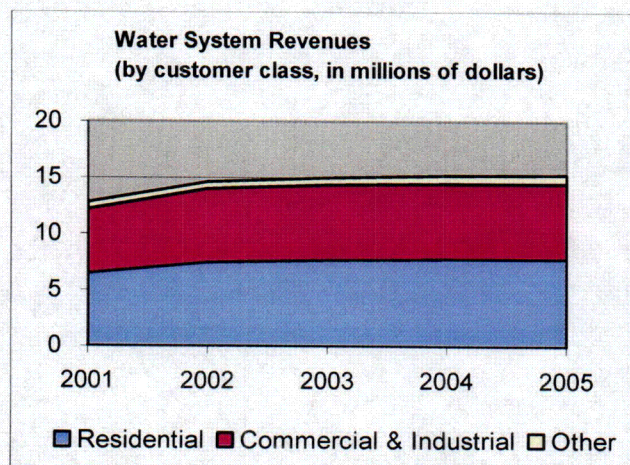
The Water System provides water to all areas within the City, and two water districts and one private water utility outside the City. During 2005 the Water System sold 1.0 billion gallons of water (10.2% of total sales) to the water districts. Water is supplied from the McKenzie River and is treated at the Hayden Bridge Filtration Plant, the largest full-treatment plant in Oregon. Water is pumped from the Hayden Bridge Filtration Plant into the distribution system through two large transmission mains. The water distribution system consists of 27 enclosed reservoirs with a combined storage capacity of 93.5 million gallons, 32 pump stations and over 790 miles of distribution mains.

**EUGENE WATER & ELECTRIC BOARD
MANAGEMENT'S DISCUSSION AND ANALYSIS**



Financial Summary and Analysis

The Water System operating revenues in 2005 were similar to revenues in 2004, however, operation and maintenance costs were higher. The result was a decrease in net operating income by \$614,000 (or 40%) in comparison to 2004. Income before contributed capital was \$401,000, which was 37% higher than in 2004. However, water rates were increased in April of 2004 by 5.6%, which helped to offset higher operational costs in 2005.



EUGENE WATER & ELECTRIC BOARD
MANAGEMENT'S DISCUSSION AND ANALYSIS

Selected Financial Data

<i>(in millions of dollars)</i>	2005	2004
Operating revenues	\$ 15.3	\$ 15.2
Operating expenses	14.4	13.7
Net operating income	0.9	1.5
Other revenues	1.0	0.6
Other expenses	(1.5)	(1.8)
Income before contributed capital	0.4	0.3
Contributed capital	3.9	2.9
Change in net assets	\$ 4.3	\$ 3.2
 Total assets	 \$ 81.4	 \$ 86.4
 Total liabilities	 \$ 31.3	 \$ 40.6
Net assets		
Invested in capital assets, net of related debt	31.9	28.1
Restricted	0.8	1.4
Unrestricted	17.3	16.3
Total net assets	50.1	45.8
Total liabilities and net assets	\$ 81.4	\$ 86.4

Capital Asset and Long-Term Debt Activity

Total Water System plant in service as of December 31, 2005 and 2004 consisted of the following:

<i>(in millions of dollars)</i>	2005	2004
Production	\$ 32	\$ 30
Transmission and distribution	72	66
General plant	5	5
 Total water system plant in service	 \$ 109	 \$ 101

As of year end the Water System had \$109 million invested in a variety of capital assets. Utility plant in service, net of accumulated depreciation, was \$45.4 million. This represented an increase of \$5.7 million (7%) over 2004. Capital construction is provided for through a combination of construction fees, cash flow from revenues, and long-term revenue bonds.

**EUGENE WATER & ELECTRIC BOARD
MANAGEMENT'S DISCUSSION AND ANALYSIS**

Total liabilities as of December 31, 2005 and 2004 consisted of the following:

(in millions of dollars)

	<u>2005</u>	<u>2004</u>
Current liabilities	\$ 3	\$ 3
Noncurrent liabilities	<u>28</u>	<u>38</u>
Total liabilities	<u>\$ 31</u>	<u>\$ 41</u>

At year end the Water System had \$23.8 million of revenue bonds outstanding versus \$32.9 million at prior year-end. During 2005 \$12.5 million of Water System Refunding Bonds were issued to obtain savings in interest costs. As part of the refunding plan, \$8.7 million of unspent cash from a prior bond issue was used to reduce debt service requirements.

System Rates

Over the last several years the demand for the water supply from customers continues to be lower than anticipated, resulting in lower than projected revenues. Therefore, during 2006, water rates are expected to increase 9.5%.

Summary

The management of the Board is responsible for preparing the information in this management's discussion and analysis, financial statements and notes to financial statements. The financial statements are prepared according to accounting principles generally accepted in the United States of America, and they fairly portray the Board's financial position and operating results. The notes to the financial statements are an integral part of the basic financial statements and provide additional information.

**EUGENE WATER & ELECTRIC BOARD
ELECTRIC AND WATER SYSTEMS
BALANCE SHEETS
DECEMBER 31, 2005**

	Electric System	Water System	Total Systems
ASSETS			
Utility plant in service	\$ 472,251,800	\$ 109,103,294	\$ 581,355,094
Less accumulated depreciation	251,655,391	63,696,733	315,352,124
Net utility plant in service	220,596,409	45,406,561	266,002,970
Property held for future use	2,390,372	979,788	3,370,160
Construction work in progress	26,478,248	9,306,595	35,784,843
Net utility plant	249,465,029	55,692,944	305,157,973
Construction funds	2,270,793	-	2,270,793
System development charge reserves	-	9,051,266	9,051,266
Investments for debt service	7,749,842	825,293	8,575,135
Restricted cash and investments	10,020,635	9,876,559	19,897,194
Cash and cash equivalents	12,841,124	1,397,834	14,238,958
Short-term investments	8,605,724	-	8,605,724
Designated cash and investments			
Purchased power reserve	11,832,760	-	11,832,760
Capital improvement reserve	7,673,338	2,992,060	10,665,398
Operating reserve	1,013,311	144,403	1,157,714
Pension and medical reserve	8,217,777	1,842,066	10,059,843
Receivables, less allowances	36,258,549	1,201,879	37,460,428
Materials and supplies, at average cost	2,432,753	418,166	2,850,919
Prepayments and special deposits	5,674,016	575,724	6,249,740
Total current assets	94,549,352	8,572,132	103,121,484
Prepaid retirement obligation	19,038,755	4,759,686	23,798,441
Investment in Western Generation Agency	8,726,974	-	8,726,974
Long-term receivable, conservation and other	5,266,441	-	5,266,441
Note receivable, water	4,989,995	-	-
Deferred charges and other	40,877,294	2,473,028	43,350,322
Total other assets	78,899,459	7,232,714	81,142,178
Total assets	\$ 432,934,475	\$ 81,374,349	\$ 509,318,829

Note: Inter-System note payable and receivable are eliminated in the Total Systems column.

**EUGENE WATER & ELECTRIC BOARD
ELECTRIC AND WATER SYSTEMS
BALANCE SHEETS
DECEMBER 31, 2005**

	Electric System	Water System	Total Systems
LIABILITIES			
Payables	\$ 34,479,547	\$ 473,211	\$ 34,952,758
Accrued payroll and benefits	3,197,831	730,478	3,928,309
Accrued interest on long-term debt	4,444,258	441,425	4,885,683
Long-term debt due within one year	7,890,000	905,000	8,795,000
Current liabilities	50,011,636	2,550,114	52,561,750
Long-term debt, bonds payable	206,281,335	22,871,884	229,153,219
Note payable, electric	-	4,989,995	-
Other liabilities and deferred credits	12,511,674	908,586	13,420,260
Total liabilities	268,804,645	31,320,579	295,135,229
NET ASSETS			
Invested in capital assets, net of related debt	94,120,354	31,916,059	126,036,413
Restricted for			
Capital projects	2,216,205	-	2,216,205
Debt service	7,749,842	825,293	8,575,135
Unrestricted	60,043,429	17,312,418	77,355,847
Total net assets	164,129,830	50,053,770	214,183,600
Total liabilities and net assets	\$ 432,934,475	\$ 81,374,349	\$ 509,318,829

Note: InterSystem note payable and receivable are eliminated in the Total Systems column.

EUGENE WATER & ELECTRIC BOARD
ELECTRIC AND WATER SYSTEMS
STATEMENTS OF REVENUES, EXPENSES AND CHANGES IN FUND NET ASSETS
YEAR ENDED DECEMBER 31, 2005

	Electric System	Water System	Total Systems
Residential	\$ 74,952,601	\$ 7,769,386	\$ 82,721,987
Commercial and industrial	98,033,592	6,663,814	104,697,406
Sales for resale and other	45,134,076	870,165	46,004,241
Operating revenues	218,120,269	15,303,365	233,423,634
Purchased power	102,004,065	-	102,004,065
System control	4,243,382	-	4,243,382
Wheeling	10,586,182	-	10,586,182
Steam and hydraulic generation	11,403,035	-	11,403,035
Transmission and distribution	14,079,774	4,887,220	18,966,994
Source of supply, pumping and purification	-	2,576,872	2,576,872
Customer accounting	7,366,564	1,082,709	8,449,273
Conservation expenses	1,653,461	570,394	2,223,855
Administrative and general	12,246,933	2,778,961	15,025,894
Depreciation on utility plant	10,976,012	2,477,362	13,453,374
Operating expenses	174,559,408	14,373,518	188,932,926
Net operating income	43,560,861	929,847	44,490,708
Interest earnings on investments	3,043,719	563,871	3,607,590
Allowance for funds used during construction	237,019	154,306	391,325
Other revenue	1,748,010	245,842	1,993,852
Other revenues	5,028,748	964,019	5,992,767
Contributions in lieu of taxes	11,052,512	-	11,052,512
Other revenue deductions	7,847,624	3,410	7,851,034
Interest expense and related amortization	10,967,378	1,574,808	12,542,186
Allowance for borrowed funds used during construction	(313,100)	(85,300)	(398,400)
Other expenses	29,554,414	1,492,918	31,047,332
Income before contributed capital	19,035,195	400,948	19,436,143
Contributed capital	3,209,529	3,901,690	7,111,219
Change in net assets	22,244,724	4,302,638	26,547,362
Total net assets at beginning of year	141,885,106	45,751,132	187,636,238
Total net assets at end of year	\$ 164,129,830	\$ 50,053,770	\$ 214,183,600

**EUGENE WATER & ELECTRIC BOARD
ELECTRIC AND WATER SYSTEMS
STATEMENTS OF CASH FLOWS
YEAR ENDED DECEMBER 31, 2005**

	Electric System	Water System	Total Systems
CASH FLOWS FROM OPERATING ACTIVITIES			
Receipts from customers	\$ 217,929,908	\$ 15,549,205	\$ 233,479,113
Other receipts	1,503,701	262,349	1,766,050
Power purchases	(103,801,760)	-	(103,801,760)
Payments to suppliers	(34,502,744)	(5,285,829)	(39,788,573)
Payments to employees	(24,516,342)	(6,043,522)	(30,559,864)
Contribution in lieu of taxes	(10,827,112)	-	(10,827,112)
Net cash from operating activities	45,785,651	4,482,203	50,267,854
CASH FLOWS FROM INVESTING ACTIVITIES			
Purchases of investment securities	(95,793,486)	(26,273,151)	(122,066,637)
Proceeds from sale and maturities of investments	78,490,181	33,392,988	111,883,169
Interest on investments (including investment in WGA)	2,920,462	540,891	3,461,353
Distribution from equity investment in WGA	1,042,034	-	1,042,034
Net cash from investing activities	(13,340,809)	7,660,728	(5,680,081)
CASH FLOWS FROM NONCAPITAL FINANCING ACTIVITIES			
Note receipts from Water	230,307	-	-
Note payments to Electric	-	(230,307)	-
Net cash from noncapital financing activities	230,307	(230,307)	-
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES			
Proceeds from bonds	10,841,483	12,661,225	23,502,708
Refunding of bonds	-	(21,040,047)	(21,040,047)
Bond principal payments	(6,145,000)	(860,000)	(7,005,000)
Bond issuance costs	(370,806)	(338,247)	(709,053)
Additions to utility plant	(16,381,138)	(4,704,250)	(21,085,388)
Interest payments	(10,202,716)	(1,710,076)	(11,912,792)
Conservation receipts from BPA	2,903,442	-	2,903,442
Additions to conservation assets and other	(11,823,740)	-	(11,823,740)
Contributed capital	3,209,529	3,901,690	7,111,219
Net cash from capital and related financing activities	(27,968,946)	(12,089,705)	(40,058,651)
CHANGE IN CASH AND CASH EQUIVALENTS	4,706,203	(177,081)	4,529,122
CASH AND CASH EQUIVALENTS, beginning of year	22,281,448	7,996,244	30,277,692
CASH AND CASH EQUIVALENTS, end of year including cash and cash equivalents restricted or designated: \$14,146,527 and \$6,421,329 for Electric and Water, respectively.	\$ 26,987,651	\$ 7,819,163	\$ 34,806,814

NON-CASH CAPITAL ACTIVITY:

In 2005, the Electric System acquired land for \$1,600,000. A payment of \$600,000 was made, and a land sales contract was agreed to for \$1 million.

See accompanying notes.

**EUGENE WATER & ELECTRIC BOARD
ELECTRIC AND WATER SYSTEMS
STATEMENTS OF CASH FLOWS
YEAR ENDED DECEMBER 31, 2005**

	<u>Electric System</u>	<u>Water System</u>	<u>Total Systems</u>
RECONCILIATION OF NET OPERATING INCOME			
TO NET CASH FROM OPERATING			
ACTIVITIES			
Net operating income	\$ 43,560,861	\$ 929,847	\$ 44,490,708
Adjustments to reconcile net operating income to			
net cash from operating activities			
Net depreciation	9,260,070	2,522,481	11,782,551
Contributions in lieu of taxes	(10,827,112)	-	(10,827,112)
Other revenue	1,572,489	245,842	1,818,331
Equity income from WGA	(94,423)	-	(94,423)
(Increase) decrease in assets			
Receivables	(585,063)	236,530	(348,533)
Materials and supplies	(340,212)	8,789	(331,423)
Prepayments and special deposits	(979,562)	145,987	(833,575)
Conservation loans, net	223,078	6,504	229,582
Long-term receivable, other	71,714	-	71,714
Prepaid retirement obligation	921,230	230,307	1,151,537
Deferred charges	(5,832,572)	(283,223)	(6,115,795)
Increase in liabilities			
Accounts payable, accrued payroll and benefits	5,716,832	130,099	5,846,931
Deferred credits and other	3,118,321	309,040	3,427,361
Net cash from operating activities	<u>\$ 45,785,651</u>	<u>\$ 4,482,203</u>	<u>\$ 50,267,854</u>

**EUGENE WATER & ELECTRIC BOARD
NOTES TO FINANCIAL STATEMENTS
YEAR ENDED DECEMBER 31, 2005**

Note 1 - Reporting Entity

The Eugene Water & Electric Board ("Board" or "EWEB") is an administrative unit of the City of Eugene, Oregon ("City"). However, as established by the Governmental Accounting Standards Board's ("GASB") definition of a reporting entity, the Board is considered a primary government and is not a component unit of another entity, nor are there any component units of which the Board is financially accountable. The Board is responsible for the ownership and operation of the Electric and Water Systems, and the basic financial statements include these two Systems.

The Board provides energy and water service primarily to residential, commercial and industrial customers located in a 238 square mile area, including the City of Eugene and adjacent suburban areas. The Board has the authority to fix rates and charges. In order to secure power resources, the Board has taken ownership of various generation facilities. In addition, the Board has entered into joint ventures, whereby it has taken or anticipates taking an equity position in various generation facilities. The operations and sale of energy generated from the Board's relationship with each of the facilities is subject to certain risks. Operations are contingent on various factors, such as regulation, river flow levels, licensing agreements and weather patterns.

The Board is subject to various forms of regulation under federal, state and local laws and is subject to various Federal Energy Regulatory Commission (FERC) regulations. Laws and regulations are subject to change and may have a direct impact on the operations of the Board.

The Bonneville Power Administration ("BPA") acts as a power wholesaler, and the Board is committed to purchase minimum amounts of power from BPA under various forms of net billing agreements.

Note 2 - Summary of Significant Accounting Policies

Method of Accounting

The Board maintains its accounting records in accordance with accounting principles generally accepted in the United States of America. The Board has elected to apply all applicable GASB pronouncements, as well as Financial Accounting Standards Board ("FASB") pronouncements and Accounting Principles Board ("APB") opinions issued on or before November 30, 1989, unless those pronouncements conflict with or contradict GASB pronouncements. As allowed under GASB No. 20, the Board has elected to apply all FASB Statements and Interpretations issued after November 30, 1989, except for those that conflict with or contradict GASB pronouncements.

**EUGENE WATER & ELECTRIC BOARD
NOTES TO FINANCIAL STATEMENTS
YEAR ENDED DECEMBER 31, 2005**

Note 2 - Summary of Significant Accounting Policies (Continued)

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent 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.

Cash and Cash Equivalents

The Board considers money market accounts, government investment pool holdings, and certificates of deposit to be cash equivalents.

Operating Revenue

Operating revenue is recorded on the basis of service delivered. Utility revenues are derived primarily from the sale and transmission of electricity and from the sale of water. Utility revenue from power and water sales and power transmission is recognized when the power or water is delivered to and received by the customer. Estimated revenues are accrued for power and water deliveries not yet billed to customers from meter reading dates prior to month end (unbilled revenue) and are reversed the following month when actual billings occur. The credit practices of the Board require an evaluation of each new customer's credit worthiness on a case-by-case basis. At the discretion of management, a deposit may be obtained from the customer. Concentrations of credit risk with respect to receivables for residential customers are limited due to the large number of customers comprising the Board's customer base. Credit losses have been within management's expectations. Similar to its evaluation of residential, commercial and industrial customers credit reviews, the Board continually evaluates its wholesale power customers (sales for resale revenue) by reviewing credit ratings and financial credit worthiness of existing and new customers.

Revenues are recorded net of the allowance for doubtful accounts. The allowance is determined by an examination of write off experience in the preceding five years, and consideration of other influences as appropriate. Total amounts written off at December 31, 2005 were \$345,900 for the Electric System, and \$19,600 for the Water System. (See Note 5 for allowance amounts.)

Approximately 17.6% of 2005 Electric System's retail revenues were the result of sales to two industrial customers. Approximately 4.7% of 2005 Water System's operating revenues were the result of sales to one industrial customer.

**EUGENE WATER & ELECTRIC BOARD
NOTES TO FINANCIAL STATEMENTS
YEAR ENDED DECEMBER 31, 2005**

Note 2 - Summary of Significant Accounting Policies (Continued)

Power Risk Management

The Board's Power Risk Management Guidelines set forth policies, limits and control systems governing power and fuel purchasing and sales activities for the Electric System. The objectives of such policies are to maximize benefits to customers from wholesale activities while minimizing the risk that wholesale activities will adversely affect retail prices. The Board does not enter into contracts for trading purposes.

Statement of Financial Accounting Standard (SFAS) No. 133, Accounting for Derivative Instruments and Hedging Activities, requires that every derivative instrument be recorded on the balance sheet as an asset or liability measured at its fair value, on a mark-to-market basis except as provided by the normal purchase normal sales exception of that standard. In accordance with the policy guidelines, the Board utilizes derivative instruments to minimize its exposure to commodity price risk. These instruments include electricity options, natural gas swaps and options. These contracts are considered derivative instruments under the provisions of SFAS No. 133. At December 31, 2005, net unrealized gains from derivative instruments aggregate \$6,960,279 for the Electric System. The notional amounts under such contracts totaled \$22,848,324 and the contracts extend through 2008.

The Board reports unrealized gains and losses from its mark-to-market valuations as derivative assets or liabilities on its Balance Sheets. Such unrealized gains and losses are subject to regulatory deferral because they will be recoverable in rates when the contracts are executed in the future and, accordingly, are recognized as deferred charges or credits until realized upon execution of the related contracts.

It is the Board's policy to apply, as appropriate, the normal purchase normal sales exception under SFAS No. 133, as amended by SFAS No. 138, Accounting for Certain Derivative Instruments and Hedging Activities, SFAS No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities, and relevant Derivative Implementation Group (DIG) guidance. Collectively, these statements are referred to as SFAS No. 133. Purchases and sales of forward electricity contracts that require physical delivery and which are expected to be used or sold by the reporting entity in the normal course of business are generally considered "normal purchases and normal sales" under SFAS 133. These transactions are not required to be recorded at fair value in the financial statements. The contracts qualifying as normal purchases and normal sales have aggregate notional amounts totaling \$56,913,626 and extend through 2008.

Financial Accounting Standards Board Emerging Issues Task Force Issue No. 03-11 (EITF 03-11), Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, and Not Held for Trading Purposes, requires that revenues and expenses associated with non-trading energy activities that are "booked out" (not physically settled) be reported on a net basis. Effective with the adoption of EITF 03-11, book out settlement of non-trading electricity derivative activities are now recorded on a net basis in operating revenues and expenses.

**EUGENE WATER & ELECTRIC BOARD
NOTES TO FINANCIAL STATEMENTS
YEAR ENDED DECEMBER 31, 2005**

Note 2 - Summary of Significant Accounting Policies (Continued)

Regulatory Deferrals

The Board has deferred costs to be charged to future periods as allowed by SFAS No. 71, Accounting for the Effects of Certain Types of Regulation, which follows the premise that a utility should recognize expenses at the time when the ratemaking process authorizes them to be recovered with related revenues. (See Note 7)

Conservation Assets

Conservation assets for the Electric System represent installations of energy saving measures at the properties of its customers. The deferred balance is reduced as costs are recovered, which for the most part represent debt service payments included in rates for related borrowing. Conservation assets are amortized to other revenue deductions on the statements of revenues, expenses and changes in fund net assets.

Interest Rate Swap

In 2004, the Board entered into a fixed-to-floating LIBOR interest rate swap to help convert a portion of its fixed long-term debt portfolio. This reduces the Board's interest rate costs relative to the Series 1998A bonds and provides a variable rate debt component within its overall debt portfolio. In the swap transaction, the counterparty pays the Board a fixed 3.65 percent interest rate on \$10,945,000 declining notional amount for four years. The Board will pay the counter-party if the 30-day LIBOR interest rate is higher than 3.65 percent. The Board has deferred \$322,000 in net unrealized loss for the interest rate swap. An equivalent amount is recognized as an asset in deferred charges and as a liability in deferred credits.

Prepaid Retirement Obligation

In 2001, the Electric System issued \$30 million in bonds to pay down a portion of the Board's unfunded actuarial liability for the State of Oregon Public Employees Retirement System. The Water System makes payments to the Electric System for its estimated share of the liability paid down, and both Systems treat the transaction as a prepayment amortized over the life of the bonds.

Preliminary Surveys

The Electric System has deferred certain costs associated with its investigation of several projects which it believes will be viable in the future. The balance of these costs at December 31, 2005 was \$11,326,700, primarily for the application process in relicensing the Carmen Smith Project.

**EUGENE WATER & ELECTRIC BOARD
NOTES TO FINANCIAL STATEMENTS
YEAR ENDED DECEMBER 31, 2005**

Note 2 - Summary of Significant Accounting Policies (Continued)

Utility Plant and Depreciation

Utility plant is stated at original cost. Costs include labor, materials and related indirect costs, such as engineering, transportation and allowance for funds (i.e., interest) used during construction. The cost of additions, renewals and betterments is capitalized. Repairs and minor replacements are charged to operating expenses. The cost of property and removal cost is charged to accumulated depreciation when property is retired. Included in the Board's construction work-in-progress balance are costs associated with obtaining or renewing licensing agreements, as well as meeting other regulatory requirements. Once the new or renewed licensing agreements are obtained, the Board transfers those costs to its depreciable utility plant to be depreciated over the estimated useful lives of the plant components. Depreciation is computed using straight-line group rates.

In 2005, the Board adopted GASB No. 42 regarding impairment losses of capital assets. There were no impairment events during 2005 requiring impairment tests or recognition of losses, and there were no assets with remaining book value for which to apply the recognition of impairment losses retroactively as required by the Statement.

Debt Refundings

For current and advance refundings resulting in defeasance of debt, the difference between the reacquisition price and the net carrying amount of the old debt (gain or loss) is deferred and amortized as a component of interest expense over the remaining life of the old debt or the new debt, whichever is shorter, consistent with GASB No. 23, Accounting and Financial Reporting for Refundings of Debt Reported by Proprietary Activities, and reported as a component of the new debt liability on the Balance Sheet.

Environmental Expenses

Environmental costs (i.e. fish and plant habitat enhancements) are expensed or capitalized depending upon their future economic benefits. Liabilities for such expenses are recorded when it is probable that obligations have been incurred and the costs can be reasonably estimated.

Net Assets

Net assets consist primarily of cumulative operating revenues collected for (a) payment of utility plant additions or principal amortization of debt incurred for plant additions, in advance of net accumulated depreciation recognized on such plant, and (b) interest income earned on investments. It is the Board's intention to set rates at a level to continue replacing and improving net utility plant. Net assets consist of the following components:

- **Invested in capital assets, net of related debt and deferred credits** - This component of net assets consists of (a) capital assets, (b) net of accumulated depreciation and outstanding balances of any bonds, other borrowings and deferred credits that are attributable to the acquisition, construction, or improvement of those assets.

**EUGENE WATER & ELECTRIC BOARD
NOTES TO FINANCIAL STATEMENTS
YEAR ENDED DECEMBER 31, 2005**

Note 2 - Summary of Significant Accounting Policies (Continued)

- **Restricted** - This component consists of net assets on which constraints are placed as to their use. Constraints include those imposed by creditors (such as through debt covenants), contributors, or laws or regulation of other governments or constraints imposed by law through constitutional provisions or through enabling legislation.
- **Unrestricted** - This component of net assets consists of net assets that do not meet the definition of "restricted" or "invested in capital assets, net of related debt and deferred credits."

Fair Value of Financial Instruments

The carrying amounts of current assets, including restricted cash and investments, and current liabilities approximate fair value due to the short-term maturity of those instruments. The fair value of the Board's investments and debt are estimated based on the quoted market prices for the same or similar issues.

Note 3 - Cash and Investments

The Board maintains cash and investments in several fund accounts in accordance with bond resolutions and Board authorization. Descriptions of these fund account types are as follows:

Restricted Cash and Investments

Construction funds - Used to account for legally restricted cash and investments for the purpose of construction of capital projects. Funds include proceeds from the issuance of bonds and contributions from customers or contractors for construction projects.

Systems development charge reserve - Used to account for charges assessed and collected in conjunction with installation of new water services in the Water System and are restricted by State of Oregon Statutes to system enhancements and other related capital expenditures.

Investments for debt service - Used to account for cash and investments which are restricted by Bond Indentures of Trust for future payment of principal and interest on debt.

Designated Cash and Investments

Purchased power reserve - Used to account for cash and investments which the Board has designated to reserve for fluctuations in purchased power costs.

Capital improvement reserve - Used to account for cash and investments which the Board has designated for capital improvements.

**EUGENE WATER & ELECTRIC BOARD
NOTES TO FINANCIAL STATEMENTS
YEAR ENDED DECEMBER 31, 2005**

Note 3 - Cash and Investments (Continued)

Operating reserve - Used to account for cash and investments which the Board has designated for payment of operating costs and self-insured retention claims to maintain balances in the general account within target levels.

Pension and medical reserve - Used to account for cash and investments that the Board has designated for pension and post-retirement medical costs.

Deposits with financial institutions are comprised of bank demand deposits and savings accounts. The total bank balances, as recorded in bank records at December 31, 2005, were \$4,780,111. Of the bank balances, \$100,000 were covered by federal depository insurance, and \$4,680,111 were collateralized with securities held by the pledging financial institution but not in the Board's name.

The Board's investments during the year, which included obligations of the U.S. Government, are authorized by State of Oregon Statutes and bond resolutions. As of December 31, 2005, the Board held the following investments and maturities (Electric and Water Systems combined):

Investment Type	Carrying Value	Weighted Average Maturity (Years)	% of Portfolio
Local Government Investment Pool	\$ 31,888,974	0.003	43.4%
U.S. Agency Securities	41,650,777	0.307	56.6%
Total	<u>\$ 73,539,751</u>	<u>0.310</u>	<u>100%</u>

The "weighted average maturity in years" calculation assumes that all investments are held until maturity.

As a means of limiting its exposure to fair value losses resulting from rising interest rates, the Board's investment policy limits at least 75% of its investment portfolio to maturities of less than 18 months. Investment maturities are limited as follows:

Maturity	Minumum Investment
Less than 30 days	5%
Less than 90 days	15%
Less than 180 days	25%
Less than 18 months	75%
Less than 3 years	100%

**EUGENE WATER & ELECTRIC BOARD
NOTES TO FINANCIAL STATEMENTS
YEAR ENDED DECEMBER 31, 2005**

Note 3 - Cash and Investments (Continued)

With the exception of pass-through funds, the maximum amount of pooled investments to be placed in the Local Government Investment Pool is limited by State of Oregon Statute to \$38,262,295, which amount will increase proportionately to the Portland Consumer Price Index. The limit can be exceeded for ten business days.

Custodial credit risk is the risk that, in the event of the failure of the counterparty, the Board will not be able to recover the value of its investments or collateral securities that are in the possession of an outside party. All of the aforementioned investments, except for the investments in the Local Government Investment Pool, which are not evidenced by securities, are held in the Board's name by a third-party custodian.

Concentration of credit risk is the risk that, when investments are concentrated in one issuer, this concentration presents a heightened risk of potential loss. Of the Board's total investments as of December 31, 2005, 43% is invested in the State of Oregon Local Government Investment Pool and 57% in direct obligations of the U.S. Government.

The Board's policy, which adheres to Oregon statutes, is to limit its investments to the top two ratings issued by nationally recognized statistical rating organizations. As a general practice, and in a further effort to minimize credit risk, the Board concentrates on U.S. agency investments and investments in the Local Government Investment Pool, and generally invests only in top rated commercial paper and corporate bonds. In all instances, the Board actively evaluates the credit worthiness of the financial institutions with which it invests.

**EUGENE WATER & ELECTRIC BOARD
NOTES TO FINANCIAL STATEMENTS
YEAR ENDED DECEMBER 31, 2005**

Note 3 - Cash and Investments (Continued)

Cash and investments consist of the following at December 31, 2005:

	<u>Restricted Cash and Investments</u>	<u>Cash and Cash Equivalents</u>	<u>Short-Term Investments</u>	<u>Designated Funds</u>	<u>Total Carrying Amount</u>
ELECTRIC SYSTEM					
Cash on hand	\$ -	\$ 11,800	\$ -	\$ -	\$ 11,800
Cash in bank	-	2,093,314	-	-	2,093,314
Investments in the State of Oregon local government investment pool	2,270,793	10,736,010	-	11,875,734	24,882,537
Investments - direct obligations of U.S. government	<u>7,749,842</u>	<u>-</u>	<u>8,605,724</u>	<u>16,861,452</u>	<u>33,217,018</u>
Total electric system	<u>\$ 10,020,635</u>	<u>\$ 12,841,124</u>	<u>\$ 8,605,724</u>	<u>\$ 28,737,186</u>	<u>\$ 60,204,669</u>
WATER SYSTEM					
Cash in bank	\$ -	\$ 812,726	\$ -	\$ -	\$ 812,726
Investments in the State of Oregon local government investment pool	2,529,391	585,108	-	3,891,938	7,006,437
Investments - direct obligations of U.S. government	<u>7,347,168</u>	<u>-</u>	<u>-</u>	<u>1,086,591</u>	<u>8,433,759</u>
Total water system	<u>\$ 9,876,559</u>	<u>\$ 1,397,834</u>	<u>\$ -</u>	<u>\$ 4,978,529</u>	<u>\$ 16,252,922</u>
	<u>\$ 19,897,194</u>	<u>\$ 14,238,958</u>	<u>\$ 8,605,724</u>	<u>\$ 33,715,715</u>	<u>\$ 76,457,591</u>

EUGENE WATER & ELECTRIC BOARD
NOTES TO FINANCIAL STATEMENTS
YEAR ENDED DECEMBER 31, 2005

Note 4 - Utility Plant

The major classifications and depreciable lives of utility plant in service at December 31 2005, are as follows:

Electric Utility Plant

	Depreciable Life -Years	Balance at December 31, 2004	Increases	Decreases	Balance at December 31, 2005
Land		\$ 6,133,391	\$ 18,062	\$ (185,825)	\$ 5,965,628
Steam production	10-25	18,983,255	63,438	(999,715)	18,046,978
Hydro production	36-50	130,161,083	6,351,409	-	136,512,492
Wind production	25	13,087,182	-	-	13,087,182
Transmission	33.3-50	53,677,711	1,032,308	-	54,710,019
Distribution	28.5	164,346,213	7,571,668	(753,475)	171,164,406
General plant	3-50	67,355,406	5,732,674	(322,985)	72,765,095
Total utility plant in service		453,744,241	20,769,559	(2,262,000)	472,251,800
Accumulated depreciation		(242,395,323)	(11,441,375)	2,181,307	(251,655,391)
Property held for future use		739,429	1,650,943	-	2,390,372
Construction work in progress		29,677,675	15,767,577	(18,967,004)	26,478,248
Net utility plant		<u>\$ 241,766,022</u>	<u>\$ 26,746,704</u>	<u>\$ (19,047,697)</u>	<u>\$ 249,465,029</u>

Water Utility Plant

	Depreciable Life -Years	Balance at December 31, 2004	Increases	Decreases	Balance at December 31, 2005
Land		\$ 637,411	\$ 53,744	\$ -	\$ 691,155
Structure	50	22,383,503	1,667,855	-	24,051,358
Pumping	20	6,159,267	586,371	-	6,745,638
Purification	25	1,157,202	516	-	1,157,718
Transmission	28.5	17,196,188	-	-	17,196,188
Reservoirs	50	10,971,461	2,728,618	-	13,700,079
Distribution	28.5	29,846,054	2,239,676	-	32,085,730
Services, meters and hydrants	20-28.5	7,942,837	567,020	-	8,509,857
General plant	3-50	4,531,738	461,170	(27,337)	4,965,571
Total utility plant in service		100,825,661	8,304,970	(27,337)	109,103,294
Accumulated depreciation		(61,174,252)	(2,550,543)	28,062	(63,696,733)
Property held for future use		903,106	76,682	-	979,788
Construction work in progress		12,802,778	4,270,231	(7,766,414)	9,306,595
Net utility plant		<u>\$ 53,357,293</u>	<u>\$ 10,101,340</u>	<u>\$ (7,765,689)</u>	<u>\$ 55,692,944</u>

**EUGENE WATER & ELECTRIC BOARD
NOTES TO FINANCIAL STATEMENTS
YEAR ENDED DECEMBER 31, 2005**

Note 5 - Receivables

A summary of significant receivables is as follows:

	Electric System	Water System
Accounts receivable	\$ 33,700,883	\$ 1,150,761
Allowance for doubtful accounts	(319,699)	(19,646)
Net accounts receivable	33,381,184	1,131,115
Conservation loans to customers	1,437,112	-
Interest receivable	570,431	-
Miscellaneous receivables	455,910	70,764
Note receivable (Bonneville Power Administration)	178,359	-
Renewable Energy Production Incentive (REPI)	235,553	-
Receivables (current)	<u>\$ 36,258,549</u>	<u>\$ 1,201,879</u>
Conservation loans to customers	\$ 4,335,704	
Note receivable (Bonneville Power Administration)	836,663	
Renewable Energy Production Incentive (REPI)	94,074	
Long-term receivables	<u>\$ 5,266,441</u>	

Note 6 - Investment in Western Generation Agency

The Board is a party to an Intergovernmental Agency Agreement, whereby the Board was obligated to make equity investments in the Western Generation Agency (the Agency) as partial funding for the construction of the Wauna Cogeneration Project (the Project). As of December 31, 1996, the Board had made all required equity investments, totaling \$15,100,000, to the Agency. The Project agreements allow the Board to be repaid its equity investment plus a cumulative preferred dividend at 7.875% should the operating revenues of the Project be sufficient to cover operating costs, debt service, plus other reserve requirements. During 2005, distributions totaling \$1,042,034 were received, of which \$402,644 was a preferred equity distribution. The repayment of the entire equity investment is contingent upon the successful operation of the Project and is not guaranteed. Should the Project fail to generate sufficient revenues, the repayment of the equity contribution may occur only in part or not at all. At December 31, 2005, the Board has recorded a receivable in the amount of \$568,111 for the preferred dividend, which is included in other revenue.

EUGENE WATER & ELECTRIC BOARD
NOTES TO FINANCIAL STATEMENTS
YEAR ENDED DECEMBER 31, 2005

Note 6 - Investment in Western Generation Agency (Continued)

The balance of the investment in Western Generation Agency as of December 31, 2005 was \$8,726,974 and has been decreased by the equity distributions previously described and increased by the Board's 50% share of Agency's 2005 net income, or \$94,000. The Board is committed, through a power purchase agreement, to purchase the output from the Project through the year 2021. The Board has agreed to suspend its agreement with the Agency in favor of a separate purchase power agreement between the Agency and the BPA through the year 2016. Financial information for the Project is included in the financial statements of the Agency and may be obtained from the Agency's trustee, Wells Fargo Bank.

Note 7 - Deferred Charges and Other and Other Liabilities and Deferred Credits

Deferred charges and other and other liabilities and deferred credits at December 31, 2005 were as follows:

	Electric System	Water System
Deferred charges and other		
Regulatory assets		
Derivatives - market value (See Note 2)	\$ 6,960,279	\$ -
Interest rate swap - market value	322,000	-
Sick leave - upon retirement	1,348,613	337,153
Net pension obligation - supplemental retirement plan	1,048,607	262,152
Conservation assets	13,334,523	-
Unamortized bond expense	2,897,008	811,383
Preliminary surveys	11,326,659	-
Prepaid option premiums (See Note 2)	3,639,043	-
Other	562	-
Lease prepayment	-	992,243
Unamortized loss on defeasance	-	70,097
	<u>\$ 40,877,294</u>	<u>\$ 2,473,028</u>
Deferred charges and other		
Other liabilities and deferred credits		
Regulatory liabilities		
Derivatives - market value	\$ 6,960,279	\$ -
Interest rate swap - market value	322,000	-
Sick leave - upon retirement	1,348,613	337,153
Net pension obligation - supplemental retirement plan	1,048,607	262,152
Note payable on land	920,495	-
Other	1,911,680	309,281
	<u>\$ 12,511,674</u>	<u>\$ 908,586</u>
Other liabilities and deferred credits		

**EUGENE WATER & ELECTRIC BOARD
NOTES TO FINANCIAL STATEMENTS
YEAR ENDED DECEMBER 31, 2005**

Note 8 - Payables

Current payables at December 31, 2005 were as follows:

	Electric System	Water System
Accounts payable	\$ 25,413,186	\$ 259,436
Construction payables	884,491	-
Contributions in lieu of taxes	775,805	-
Customer deposits	3,112,989	-
Due to bank/cash transfers pending	2,394,060	-
Miscellaneous payables	744,972	213,775
Preliminary investigations payables	1,154,044	-
	<u>\$ 34,479,547</u>	<u>\$ 473,211</u>

EUGENE WATER & ELECTRIC BOARD
NOTES TO FINANCIAL STATEMENTS
YEAR ENDED DECEMBER 31, 2005

Note 9 - Long-Term Debt

Long-term portion of bonds payable at December 31, 2005:

Electric Utility System Revenue and Refunding Bonds	
1996 Series, 12-10-96 issue	
Serial Bonds, 4.90% - 5.375%, due 2006-2013	\$ 7,995,000
Term Bonds, 5.60%, due 2014-2016	4,425,000
1997 Series, 10-1-97 issue, 4.5% - 5.00%, due 2006-2011	6,450,000
1998 Series, 2-1-98 issue	
Serial Bonds, 4.3% - 4.85%, due 2006-2015	9,310,000
Term Bonds, 5.00% - 5.05%, due 2016-2022	23,875,000
1998 Series A, 11-15-98 issue	
Serial Bonds, 5.86% - 5.97%, due 2006-2009	1,130,000
Term Bonds, 6.22% - 6.85%, due 2010-2023	9,165,000
2001 Series A, 11-15-01 issue	
Term Bonds, 6.32%, due 2006-2022	25,660,000
Capital appreciation, 7.13% - 7.21%, due 2023-2027	4,067,556
2001 Series B, 11-15-01 issue	
Serial Bonds, 4.00% - 5.25%, due 2006-2022	18,695,000
Term bonds, 5.00%, due 2023-2031	19,140,000
2002 Series A, 5-7-02 issue	
5.25%, due 2006-2011	7,520,000
2002 Series B, 6-1-02 issue	
4.875% - 5.96%, due 2006-2012	7,855,000
2002 Series C, 6-1-02 issue	
3.125% - 5.0%, due 2006-2022	10,945,000
2003 Series, 6-10-03 issue	
2.0% - 5.0%, due 2006-2022	39,415,000
2005 Series, 5-10-05 issue	
Serial Bonds, 3.00% - 5.0%, due 2006-2020	6,690,000
Term bonds, 4.5%, due 2022 & 2025	3,530,000
	<u>205,867,556</u>
Add unamortized premium	2,986,260
Less unamortized refunding costs	(1,773,629)
Less unamortized discount	<u>(798,852)</u>
Electric System Bonds payable	<u>206,281,335</u>

EUGENE WATER & ELECTRIC BOARD
NOTES TO FINANCIAL STATEMENTS
YEAR ENDED DECEMBER 31, 2005

Note 9 - Long-Term Debt (Continued)

Water Utility System Revenue and Refunding Bonds	
2000 Series, 6-1-00 issue, 5.20% - 5.30% due 2007-2010	1,935,000
2002 Series, 8-1-02 issue, 2.75% - 4.7%, due 2007-2022	10,000,000
2005 Series, 8-16-05 issue	
Serial Bonds, 3.5% - 5.0%, due 2011-2025	8,360,000
Term bonds, 4.35%, due 2030	4,180,000
Note payable - Electric	
11-15-01 issue, 6.32% - 7.21%, due 2006-2027	4,989,995
	29,464,995
Add unamortized premium	118,751
Less unamortized discount	(174,958)
Less unamortized refunding costs	(1,546,909)
Water System bonds and note payable	27,861,879
Total long-term portion of debt	234,143,214
Less inter system payable	4,989,995
Total Systems long-term debt, bonds payable	<u>\$ 229,153,219</u>

The carrying amount and fair value of current and long-term debt at December 31, 2005 were as follows:

	Carrying Amount	Fair Value
Electric System	\$ 214,171,335	\$ 226,356,855
Water System	23,776,884	25,420,900
Total bonds payable	<u>\$ 237,948,219</u>	<u>\$ 251,777,755</u>

**EUGENE WATER & ELECTRIC BOARD
NOTES TO FINANCIAL STATEMENTS
YEAR ENDED DECEMBER 31, 2005**

Note 9 - Long-Term Debt (Continued)

The schedule of maturities for principal and interest is as follows:

	Electric System		Water System	
	Principal	Interest	Principal	Interest
2006	\$ 7,890,000	\$ 10,666,213	\$ 905,000	\$ 1,059,418
2007	9,075,000	10,327,294	910,000	1,040,426
2008	9,685,000	9,924,930	940,000	2,126,604
2009	10,330,000	9,483,179	985,000	2,087,242
2010	11,005,000	9,003,318	1,025,000	2,045,082
2011 - 2015	49,095,000	37,354,152	5,080,000	4,031,271
2016 - 2020	58,475,000	23,929,843	6,285,000	2,874,244
2021 - 2025	42,991,437	17,739,802	5,070,000	1,455,758
2026 - 2030	12,646,119	10,013,881	4,180,000	561,150
2031	2,565,000	128,250	-	-
	<u>\$ 213,757,556</u>	<u>\$ 138,570,862</u>	<u>\$ 25,380,000</u>	<u>\$ 17,281,195</u>

The resolutions authorizing the issuance of revenue bonds contain various covenants, sinking fund requirements and obligations with which the Board must comply. The principal and interest requirements are reflected in the supplementary schedule "Long-Term Bonded Debt and Interest Payment Requirements". To comply with sinking fund deposit requirements, the Board deposits monthly one-twelfth of the annual deposit requirement with the trustee, less accumulated interest. The interest payments are made semi-annually on February 1 and August 1, and principal payments on August 1.

The Board entered, but had not drawn on a non-revolving demand line of credit on December 23, 2003 with a combination of prime and the LIBOR interest rate for a maximum of \$30 million. The Board renewed the line of credit on December 31, 2005 with no balance outstanding.

In May 2005, the Board issued \$10,575,000 in Electric Utility Revenue Bonds with interest rates from 3.0% to 4.5% maturing in 2025 for the Carmen Smith Hydroelectric Project and the preliminary design of a new headquarters facility.

In August of 2005, the Water Utility issued the 2005 Revenue Refunding Series bond for \$12,540,000 with rates from 3.5% to 5.0% maturing in 2030 to partially advance refund a portion of the Water Utility Revenue Bonds Series 2000. The Board deposited \$8,707,000 of funds from the 2002 Series Bond to pay down the 2000 Series debt.

**EUGENE WATER & ELECTRIC BOARD
NOTES TO FINANCIAL STATEMENTS
YEAR ENDED DECEMBER 31, 2005**

Note 9 - Long-Term Debt (Continued)

The 2005 Water System refunding resulted in an accounting loss of \$1,570,000 to be amortized over the life of the defeased bond issue, the Board reduced its debt service by \$17.5 million over 25 years and obtained an economic gain (difference between the present values of the old and the new debt service payments) of \$1.83 million.

As of December 31, 2005 the amount of defeased debt still outstanding but removed from the Board's long-term debt amounted to \$22,359,000 for the Water System. The refunded bonds constitute a contingent liability of the Board only to the extent that cash and investments presently in the control of the refunding trustees are not sufficient to meet debt service requirements, and are therefore excluded from the financial statements because the likelihood of additional funding requirements is considered remote.

Long-term debt activity for the year is as follows:

	Outstanding January 1, 2005	Issued During Year	Redeemed During Year	Outstanding December 31, 2005
Electric Revenue Bonds, with interest rates from 3.0% to 6.85%, maturing through 2031 (original issue \$200,805,000)	\$ 74,560,000	\$ 10,575,000	\$ (3,010,000)	\$ 82,125,000
Electric Revenue Refunding Bonds, with interest rates from 2.0% to 5.25%, maturing through 2022 (original issue \$127,190,000)	104,770,000	-	(3,045,000)	101,725,000
Electric Revenue Current Interest Bonds, with interest rate of 6.32%, maturing through 2027 (original issue \$29,997,556)	29,997,556	-	(90,000)	29,907,556
Total Electric System	209,327,556	10,575,000	(6,145,000)	213,757,556
Water Revenue Refunding Bonds, with interest rates from 3.5% to 5.0%, maturing through 2030 (original issue \$19,155,000)	1,765,000	12,540,000	(860,000)	13,445,000
Water Revenue Bonds, with interest rates from 2.75% to 5.30%, maturing through 2022 (original issue \$31,405,000)	31,405,000	-	(19,470,000)	11,935,000
Total Water System	33,170,000	12,540,000	(20,330,000)	25,380,000
Total bonded debt	\$ 242,497,556	\$ 23,115,000	\$ (26,475,000)	\$ 239,137,556

EUGENE WATER & ELECTRIC BOARD
NOTES TO FINANCIAL STATEMENTS
YEAR ENDED DECEMBER 31, 2005

Note 9 - Long-Term Debt (Continued)

The Board entered into a \$1 million, ten-year, land sale contract in 2005 as part of the purchase terms of land being considered for new administrative and operational space in Eugene. The long-term portion of this contract is reported in other liabilities and deferred credits. The short-term portion of this contract is reported in payables.

Note 10 - Power Supply Resources

The Board maintains purchase power purchase agreements with BPA and various other regional utilities. These agreements began expiring during 2001 and will continue through 2031 and may be renewed at the Board's option, prior to expiration. A significant portion of the power received from BPA is provided under the "Slice" contract. The Slice contract provides for certain periodic adjustments and true-ups based on actual BPA costs. All BPA assessed true-ups have been fully accrued for 2005; however, certain of these costs are subject to refund by BPA upon certain findings.

Expected costs for power supply contracts are as follows:

2006	\$ 91,168,000
2007	98,690,000
2008	98,571,000
2009	98,629,000
2010	98,002,000
Thereafter	<u>267,651,000</u>
	<u>\$ 752,711,000</u>

Amounts to be paid under the Board's power supply contracts are subject to significant variation based on changes in rates and volumes, therefore the above should be considered estimates.

During 2005 the Board purchased approximately 56% of its power requirements from BPA, approximately 32% from sources other than BPA, and generated approximately 12%.

Note 11 - Retirement Benefits

Plan Description

The Board's pension plan provides retirement and disability benefits, annual cost-of-living adjustments and death benefits to members or their beneficiaries. The Board is a participating employer in the Oregon Public Employees Retirement System ("OPERS") and Oregon Public Service Retirement Plan ("OPSRP"). The OPERS Board administers both plans, which are established under Oregon Revised Statutes and acts as a common investment and administrative agent for public employers in the State of Oregon.

OPSRP was created during the 2003 Oregon Legislative session and represents the pension plan for public employees hired on or after August 29, 2003, unless membership was previously established in OPERS, which is a closed plan. All Board employees are eligible to participate in OPSRP after six months of employment. Benefits are established under both plans by State Statute and employer contributions are made at an actuarially determined rate as adopted by the Public Employees Retirement Board ("Retirement Board"). The OPERS, a component unit of the State of Oregon, issues a comprehensive annual report that includes both pension plans, which may be obtained by writing to PERS.

Funding Policy

In March of 2005, OPERS issued a rate order to increase employer rates on July 1, 2005 as the result of the December 31, 2003 actuarial valuation. The rates were to be phased in over the following two years. The Board elected to take the full rate increase instead of the phase in, resulting in an employer rate increase from 11.32% to 23.51% of covered payroll effective July 1, 2005. The next actuarial valuation is for the year ended December 31, 2005, which is expected to be available in February 2007.

State of Oregon Statute requires covered employees to contribute 6% of their salary to the system, but allows the employer to pay any or all of the employees' contribution in addition to the required employer's contribution. The Board has elected to pay the employees' contributions.

In December 2001, the Board elected to make a lump-sum payment of approximately \$29,600,000, which had the effect of lowering the employer contribution rate. The lump sum payment is recorded as an other asset and is being amortized over the funding period of 27 years. The amortization was \$1,152,000 for 2005.

EUGENE WATER & ELECTRIC BOARD
NOTES TO FINANCIAL STATEMENTS
YEAR ENDED DECEMBER 31, 2005

Note 11 - Retirement Benefits (Continued)

Annual Pension Cost

Because all OPERS participating employers are required by law to submit the contributions as adopted by the Retirement Board, and because employer contributions are calculated in conformance with the parameters of GASB No. 27, Accounting for Pensions by State and Local Government Employers, there is no net pension obligation to report, and annual required contributions are equal to annual pension cost. For the year ended December 31, 2005, the Board's annual pension expense of \$6,804,000, consisted of the employer portion of \$5,014,000 and the annual required contribution of approximately \$1,790,000 (an average for 2005 of 17% of covered payroll and 6%, respectively).

The Board's pension liability and the annual required contribution rate were determined as part of the December 31, 2003 actuarial valuation using the entry age actuarial cost method. The unfunded actuarial accrued liability is amortized as a level percentage of projected annual payroll on an open basis over a 24-year period. The actuarial assumptions include a rate of return on investment of present and future assets of 8.0% per year, projected salary increases of 4.25% (excluding merit and longevity increases), and cost-of-living adjustments of 2.0% per year for postretirement benefits. Investment return and projected salary increases include an inflation component of 3.5%.

The following table presents three-year trend information for the Board's employee pension plan for the fiscal year ending December 31:

	<u>Annual Pension Cost (APC)</u>	<u>Percentage of APC Contributed</u>
2003	\$ 5,221,700	100%
2004	\$ 5,067,900	100%
2005	\$ 6,804,000	100%

The following table presents a schedule of funding progress for the Board's employee pension plan:

<u>Valuation Date</u>	<u>Value of Assets</u>	<u>Actuarial Liability</u>	<u>Unfunded Actuarial Liability (UAL)</u>	<u>Percent of Actuarial Liability Funded</u>	<u>Covered Payroll</u>	<u>UAL/Payroll</u>
12-31-99	\$ 172,684,683	\$ 227,670,647	\$ 54,985,964	76%	\$ 27,087,320	203%
12-31-01 *	\$ 197,488,997	\$ 200,261,724	\$ 2,772,727	99%	\$ 27,068,757	10%
12-31-03	\$ 186,436,249	\$ 235,598,684	\$ 49,162,435	79%	\$ 27,419,888	179%

* Revised, including 2003 legislative action.

**EUGENE WATER & ELECTRIC BOARD
NOTES TO FINANCIAL STATEMENTS
YEAR ENDED DECEMBER 31, 2005**

Note 11 - Retirement Benefits (Continued)

The Supplemental Retirement Plan

Plan description - The Supplemental Retirement Plan is a single-employer plan providing retirement, death and disability benefits to participants and their beneficiaries. It has been in effect since January 1, 1968 and was last amended and restated July 1988. The objective of the plan is to provide a benefit on retirement, which, together with the benefit from OPERS, will provide 1.67% of the highest 36-month average salary for each year of service. Independent actuaries determine employer contributions.

Funding policy - There is no required contribution rate as a percentage of payroll, since the only participants currently in the plan are retirees and their beneficiaries. Funding of the plan is made from Board contributions, as needed to meet obligations to retirees, together with earnings on plan assets.

Annual pension cost - Employer contributions are calculated and made in conformity with the parameters of GASB No. 27. The Board's annual pension cost is based upon its latest actuarial report, dated January 1, 2005, with the next actuarial valuation for the year ended December 31, 2005 scheduled to be completed during 2006.

The Board's pension liability and the annual required contribution rate were determined as part of the January 1, 2005 actuarial valuation using the unit credit method. The unfunded actuarial accrued liability is amortized as a level percentage of projected annual payroll on an open basis over a 10-year period. The actuarial assumptions include a rate of return on investment of present and future assets of 7.0% per year, cost-of-living adjustments of 2.0% per year for postretirement benefits and 1983 Group Annuity Mortality rate.

The Board's annual pension cost and the change in net pension obligation related to the Supplemental Retirement Plan is as follows:

Annual recommended contribution	\$ 487,194
Interest on net pension obligation	103,630
Adjustment to annual recommended contribution	<u>(190,777)</u>
Annual pension cost	400,047
Contributions made	<u>569,716</u>
Decrease in net pension obligation	(169,669)
Net pension obligation, January 1	<u>1,480,428</u>
Net pension obligation, December 31	<u><u>\$ 1,310,759</u></u>

**EUGENE WATER & ELECTRIC BOARD
NOTES TO FINANCIAL STATEMENTS
YEAR ENDED DECEMBER 31, 2005**

Note 11 - Retirement Benefits (Continued)

The following tables present three-year trend information for the Board's Supplemental Retirement Plan for the fiscal year ending December 31:

	Annual Pension Cost (APC)	Percentage of APC Contributed	Net Pension Obligation
2002	\$ 427,148	0%	\$ 1,633,119
2003	\$ 452,359	134%	\$ 1,480,428
2004	\$ 400,047	142%	\$ 1,310,759

The following table presents a schedule of funding progress for the Board's Supplemental Retirement Plan:

Valuation as of January 1	Value of Assets	Actuarial Liability	Net Assets as a Percent of Actuarial Liability	Unfunded Actuarial Liability
2003	\$ 112,539	\$ 3,964,935	2.8%	\$ 3,852,396
2004	\$ 172,033	\$ 3,593,882	4.8%	\$ 3,421,849
2005	\$ 219,119	\$ 3,321,548	6.6%	\$ 3,102,429

Postretirement Medical Benefit Plan

In addition to pension benefits, the Board provides postretirement health care and life insurance benefits to all employees who retire under OPERS or OPSRP with at least 11 years of service. Currently, 392 retirees or surviving spouses of retired employees are covered under the plan. The life insurance benefit is a fixed amount of \$5,000 per retiree. Health care coverage reimburses 80% of the amount of validated claims for certain medical, dental, vision and hospitalization costs.

GASB No. 12, Disclosure of Information of Postemployment Benefits Other Than Pension Benefits by State and Local Government Employers, discusses two methods for funding the above postretirement benefits. The method the Board continues to use is the "pay-as-you-go" method, resulting in recognized expenses in 2005 of approximately \$1,050,000 for the Electric System and \$171,000 for the Water System.

**EUGENE WATER & ELECTRIC BOARD
NOTES TO FINANCIAL STATEMENTS
YEAR ENDED DECEMBER 31, 2005**

Note 11 - Retirement Benefits (Continued)

The alternative method would accrue expenses as incurred and allow the Board to fund a portion of the future postemployment costs in advance on an actuarially determined basis. Under this method, the 2004 total expense, as determined by an actuarial study dated January 1, 2005, the date of the last valuation, for both the Electric System and Water System would have been approximately \$4 million. The total actuarially determined health care liability for both systems as of January 1, 2005 was approximately \$31.7 million. The unit credit funding method was used to compute the liability and assumes a 6% discount rate and a 12.5% annual rate of increase in the per capita cost of covered health care benefits for 2005. This rate is assumed to decrease gradually to 6% in the year 2017 and remain at that level thereafter. A 1% increase in the assumed health care cost trend could have a material effect on net postretirement health care costs.

Note 12 - Deferred Compensation

The Board offers all employees a deferred compensation plan created in accordance with Internal Revenue Code ("IRC") Section 457. The plan permits them to defer a portion of their salary until future years. Participation in the plan is optional. Payment from the plan is not available to employees until termination, retirement, death or unforeseeable emergency.

The Board works with separate investment providers who also provide third-party administration for all deferred compensation program funds. Participating employees have several investment options with varying degrees of market risk. The Board has no liability for losses under the plan, but does have the duty to administer the plan in a prudent manner.

The Board has little administrative involvement with the plan and does not perform the investing function. Therefore, in accordance with GASB No. 32, Accounting and Financial Reporting for Internal Revenue Code Section 457 Deferred Compensation Plans, the plan assets are not included in the accompanying balance sheet.

Note 13 - Trojan Nuclear Plant

The Trojan Nuclear Plant ("Project") is jointly owned by Portland General Electric Company ("PGE"), 67.5%; the City of Eugene, acting by and through Eugene Water & Electric Board, 30%; and Pacific Power and Light Company, 2.5%; as tenants in common. The Project ceased commercial operation in 1993 and is being decommissioned. In accordance with Governmental Accounting Standard No. 14, *The Financial Reporting Entity*, the Project is reported as a joint venture on the equity method of accounting.

**EUGENE WATER & ELECTRIC BOARD
NOTES TO FINANCIAL STATEMENTS
YEAR ENDED DECEMBER 31, 2005**

Note 13 - Trojan Nuclear Plant (Continued)

Under the terms of Net Billing Agreements, executed in 1970, BPA is obligated to pay the Board amounts sufficient to pay all of the Board's costs related to the Project, including decommissioning and debt service, notwithstanding the termination of plant output. BPA pays those costs primarily by issuing credits against the Net Billing Participant's purchases of electricity from BPA, but in some cases also makes payments in cash. The Board is required to transfer from its Electric System Fund to the Trojan Project Fund an amount equal to all net billing credits received through this agreement. The Board is then responsible for making payments from the Trojan Project Fund to the Trojan Project for the Board's share of decommissioning costs.

Since BPA is obligated to pay the Board's share of all Trojan Project costs, and has provided the Board with legally binding written assurances of its commitment to that obligation, the Board does not expect the closure and decommissioning of the Trojan Project to have any adverse effect on the Board's Electric or Water Systems. As such, the equity interest in the Project is zero. However, under the terms of the original agreements, if one of the tenants in common fails to perform on their obligation for decommissioning costs, the other tenants may be liable. This obligation may not be covered under the Net Billing Agreement mentioned previously. However, the Board believes this risk is minimal.

In 2005, the Board on behalf of the Project issued \$26,640,000 in revenue bonds with \$23,435,000 outstanding as of December 31, 2005. These bonds are secured solely by a pledge of the receipts from Trojan Project fees and charges associated with the Two-Party Net Billing Agreement with BPA. The bonds are considered conduit debt and as such are not required to be recorded in the financial statements of the Board.

A summary of the unaudited balance sheet for EWEB's share of the Trojan Project as of September 30, 2005 is as follows:

Assets	
Restricted cash and investments	\$ 717,762
Current assets	9,611,548
Long-term receivable, BPA, net	62,017,332
Deferred charges and other	542,006
Total assets	<u>\$ 72,888,648</u>
Liabilities	
Current liabilities	\$ 8,412,812
Long-term debt	15,321,041
Accumulated provision for decommissioning costs	49,154,795
Total liabilities	<u>\$ 72,888,648</u>

**EUGENE WATER & ELECTRIC BOARD
NOTES TO FINANCIAL STATEMENTS
YEAR ENDED DECEMBER 31, 2005**

Note 13 - Trojan Nuclear Plant (Continued)

The Trojan Nuclear Plant financial statements, as required under bond resolutions, can be obtained from the Eugene Water & Electric Board.

Note 14 - Commitments and Contingencies

Electric Projects

At December 31, 2005, the Board had committed to an amendment to the Joint Operating Agreement with Weyerhaeuser Company to rebuild a turbine and replace a governor system at the Weyerhaeuser Paper Mill cogeneration facility. Over the life of the agreement, the expenses related to the project are expected to be approximately \$2,400,000.

Carmen-Smith Relicensing

On July 23, 2003, with the Notice of Intent to Re-license the Carmen-Smith Hydroelectric Project, the Electric System began the re-licensing process, which initially involves considerable effort regarding environmental impacts of the Project. The Board expects to spend \$3.2 million in years 2006-2008 to complete the requirements of the application.

Self-Insurance

The Board is exposed to various risks of loss because of the Board's self-insurance retention, up to the first \$1,000,000 of exposure, per occurrence. The purchased excess liability coverage protects the Board after the Board's self-insured limit is exhausted. However, public entities are also protected under State of Oregon tort limits, which greatly reduces the cost of any single exposure (from \$50,000 to \$500,000 depending on the damages), so therefore, except in extreme cases, the Board's exposure is mitigated by law.

Claims liabilities recorded in the basic financial statements are based on the estimated ultimate loss and reserves for claims incurred as of the balance sheet date, adjusted from current trends through a case-by-case review of all claims, including incurred but not reported ("IBNR") claims. At December 31, 2005, a total claims liability of approximately \$220,000 is reported in the basic financial statements. All prior and current-year claims are fully reserved and have not been discounted.

**EUGENE WATER & ELECTRIC BOARD
NOTES TO FINANCIAL STATEMENTS
YEAR ENDED DECEMBER 31, 2005**

Note 14 - Commitments and Contingencies (Continued)

		Liability Balance at Beginning of Year	Current Year Claims and Changes in Estimates	Claim Payments	Liability Balance at End of Year
2003	General liability	\$ 131,162	\$ 221,280	\$ (58,482)	\$ 293,960
2004	General liability	\$ 293,960	\$ 164,260	\$ (103,950)	\$ 354,270
2005	General liability	\$ 354,270	\$ (23,918)	\$ (110,417)	\$ 219,935

Claims and Other Legal Proceedings

The Board was a party to various litigation contending that parties, including the Board, bought and sold electric energy in the wholesale power markets during the California energy crisis charged unjust and/or unreasonable prices. Refund claims were asserted against the Board. On September 6, 2005, the U.S. Ninth Circuit Court of Appeals issued a ruling in the case of BPA et al v. FERC. The Ninth Circuit ruled that FERC does not have jurisdiction to impose refunds for wholesale transactions of government entities. If upheld, the Ninth Circuit ruling should eliminate for EWEB any potential refund obligation imposed by FERC. The ruling is subject to rehearing by the Ninth Circuit and possible appeal to the United States Supreme Court.

In 2003, EWEB enacted reforms in its post-retirement medical benefit plan that generally raised the contributions required for participation in the medical plan. In January 2005 EWEB received an adverse Lane County Circuit Court ruling on its reforms. EWEB is in the process of appealing the lawsuit and believes it will prevail. No provision has been made in the accompanying financial statements or note disclosures for this matter.

The Board is involved in various other litigation. In the opinion of management, the ultimate outcome of these claims will not have a material effect on the Board's financial position beyond amounts already accrued as of December 31, 2005.

Environmental Matters

The Board owns land near its headquarters, which is contaminated from a former manufactured gas plant. Under a participant agreement with other entities, the Board shares in 16-2/3% of the clean up costs. Based on a feasibility study conducted by environmental consultants and the Department of Environmental Quality's stated preferences for similar contaminations, \$666,400 is included with long-term liabilities as an estimate for clean up and maintenance of the site, which has yet to commence.

SUPPLEMENTAL INFORMATION

EUGENE WATER & ELECTRIC BOARD
ELECTRIC SYSTEM

LONG-TERM BONDED DEBT AND INTEREST PAYMENT REQUIREMENTS, INCLUDING CURRENT PORTION
YEAR ENDED DECEMBER 31, 2005

	Revenue Bonds 1996 Series 12-1-96		Refunding Revenue Bonds 1997 Series 11-4-97		Refunding Revenue Bonds 1998 Series 2-1-98	
	Principal	Interest	Principal	Interest	Principal	Interest
2006	\$ 930,000	\$ 713,885	\$ 1,115,000	\$ 359,833	\$ 345,000	\$ 1,662,475
2007	975,000	668,315	1,165,000	309,658	435,000	1,647,640
2008	1,025,000	619,565	1,225,000	256,650	540,000	1,625,455
2009	1,080,000	567,290	1,285,000	199,075	650,000	1,597,915
2010	1,135,000	511,130	1,355,000	137,395	770,000	1,568,655
2011	1,195,000	450,975	1,420,000	71,000	895,000	1,533,245
2012	1,260,000	386,744	-	-	1,035,000	1,491,180
2013	1,325,000	319,019	-	-	1,190,000	1,442,018
2014	1,395,000	247,800	-	-	1,765,000	1,384,898
2015	1,475,000	169,680	-	-	2,030,000	1,300,178
2016	1,555,000	87,080	-	-	2,315,000	1,201,723
2017	-	-	-	-	2,635,000	1,085,973
2018	-	-	-	-	2,980,000	954,223
2019	-	-	-	-	3,350,000	805,223
2020	-	-	-	-	3,750,000	636,048
2021	-	-	-	-	4,190,000	446,673
2022	-	-	-	-	4,655,000	235,070
2023	-	-	-	-	-	-
2024	-	-	-	-	-	-
2025	-	-	-	-	-	-
2026	-	-	-	-	-	-
2027	-	-	-	-	-	-
2028	-	-	-	-	-	-
2029	-	-	-	-	-	-
2030	-	-	-	-	-	-
2031	-	-	-	-	-	-
	13,350,000	4,741,483	7,565,000	1,333,611	33,530,000	20,618,592
Less current	930,000	-	1,115,000	-	345,000	-
	<u>\$ 12,420,000</u>	<u>\$ 4,741,483</u>	<u>\$ 6,450,000</u>	<u>\$ 1,333,611</u>	<u>\$ 33,185,000</u>	<u>\$ 20,618,592</u>

**EUGENE WATER & ELECTRIC BOARD
ELECTRIC SYSTEM**

**LONG-TERM BONDED DEBT AND INTEREST PAYMENT REQUIREMENTS, INCLUDING CURRENT PORTION
YEAR ENDED DECEMBER 31, 2005**

	Revenue Bonds 1998 Series A 11-15-98		2001A Series Current Interest 11-15-01		Revenue Bonds 2001 B Series 11-15-01	
	Principal	Interest	Principal	Interest	Principal	Interest
2006	\$ 335,000	\$ 699,327	\$ 180,000	\$ 1,633,088	\$ 790,000	\$ 1,901,963
2007	355,000	679,696	260,000	1,621,712	820,000	1,870,363
2008	375,000	658,857	390,000	1,605,280	855,000	1,837,563
2009	400,000	636,657	510,000	1,580,632	890,000	1,803,363
2010	420,000	612,777	645,000	1,548,400	925,000	1,767,763
2011	450,000	586,653	790,000	1,507,636	960,000	1,730,763
2012	475,000	558,663	950,000	1,457,708	1,000,000	1,692,363
2013	505,000	529,118	1,125,000	1,397,668	1,040,000	1,652,363
2014	535,000	497,707	1,310,000	1,326,568	1,095,000	1,597,763
2015	570,000	464,430	1,520,000	1,243,776	1,155,000	1,540,275
2016	610,000	425,385	1,745,000	1,147,712	1,215,000	1,479,638
2017	650,000	383,600	1,990,000	1,037,428	1,275,000	1,415,850
2018	695,000	339,075	2,255,000	911,660	1,345,000	1,348,913
2019	740,000	291,468	2,545,000	769,144	1,415,000	1,278,300
2020	795,000	240,778	2,860,000	608,300	1,490,000	1,204,013
2021	850,000	186,320	3,200,000	427,548	1,565,000	1,125,788
2022	905,000	128,095	3,565,000	225,308	1,650,000	1,043,625
2023	965,000	66,099	867,106	3,097,894	1,735,000	957,000
2024	-	-	839,611	3,305,389	1,825,000	870,250
2025	-	-	814,720	3,520,280	1,915,000	779,000
2026	-	-	789,579	3,740,421	2,010,000	683,250
2027	-	-	756,540	3,913,460	2,110,000	582,750
2028	-	-	-	-	2,215,000	477,250
2029	-	-	-	-	2,325,000	366,500
2030	-	-	-	-	2,440,000	250,250
2031	-	-	-	-	2,565,000	128,250
	10,630,000	7,984,705	29,907,556	37,627,012	38,625,000	31,385,169
Less current	335,000	-	180,000	-	790,000	-
	<u>\$ 10,295,000</u>	<u>\$ 7,984,705</u>	<u>\$ 29,727,556</u>	<u>\$ 37,627,012</u>	<u>\$ 37,835,000</u>	<u>\$ 31,385,169</u>

EUGENE WATER & ELECTRIC BOARD

ELECTRIC SYSTEM

LONG-TERM BONDED DEBT AND INTEREST PAYMENT REQUIREMENTS, INCLUDING CURRENT PORTION
YEAR ENDED DECEMBER 31, 2005

	Refunding Revenue Bonds 2002 A Series 5-7-02		Revenue Bonds 2002 B Series 5-22-02		Revenue and Refunding 2002 C Series 5-22-02	
	Principal	Interest	Principal	Interest	Principal	Interest
2006	\$ 1,280,000	\$ 462,000	\$ 1,090,000	\$ 494,804	\$ 475,000	\$ 514,963
2007	1,350,000	394,800	1,145,000	441,666	495,000	500,119
2008	1,425,000	323,925	1,200,000	383,271	505,000	483,289
2009	1,500,000	249,113	1,265,000	320,871	530,000	464,351
2010	1,575,000	170,363	1,335,000	248,766	550,000	443,681
2011	1,670,000	87,675	1,415,000	171,336	575,000	420,994
2012	-	-	1,495,000	88,205	600,000	396,556
2013	-	-	-	-	620,000	370,756
2014	-	-	-	-	650,000	343,476
2015	-	-	-	-	680,000	314,226
2016	-	-	-	-	710,000	282,776
2017	-	-	-	-	740,000	249,051
2018	-	-	-	-	775,000	213,531
2019	-	-	-	-	815,000	175,750
2020	-	-	-	-	855,000	135,000
2021	-	-	-	-	900,000	92,250
2022	-	-	-	-	945,000	47,250
2023	-	-	-	-	-	-
2024	-	-	-	-	-	-
2025	-	-	-	-	-	-
2026	-	-	-	-	-	-
2027	-	-	-	-	-	-
2028	-	-	-	-	-	-
2029	-	-	-	-	-	-
2030	-	-	-	-	-	-
2031	-	-	-	-	-	-
	8,800,000	1,687,876	8,945,000	2,148,919	11,420,000	5,448,019
Less current	1,280,000	-	1,090,000	-	475,000	-
	<u>\$ 7,520,000</u>	<u>\$ 1,687,876</u>	<u>\$ 7,855,000</u>	<u>\$ 2,148,919</u>	<u>\$ 10,945,000</u>	<u>\$ 5,448,019</u>

**EUGENE WATER & ELECTRIC BOARD
ELECTRIC SYSTEM**

**LONG-TERM BONDED DEBT AND INTEREST PAYMENT REQUIREMENTS, INCLUDING CURRENT PORTION
YEAR ENDED DECEMBER 31, 2005**

	Revenue and Refunding 2003 Series 6-10-03		Revenue 2005 Series 05-10-05		Total Electric System Payments		Totals
	Principal	Interest	Principal	Interest	Principal	Interest	
2006	\$ 995,000	\$ 1,773,288	\$ 355,000	\$ 450,587	\$ 7,890,000	\$ 10,666,213	\$ 18,556,213
2007	1,710,000	1,753,387	365,000	439,938	9,075,000	10,327,294	19,402,294
2008	1,770,000	1,702,088	375,000	428,987	9,685,000	9,924,930	19,609,930
2009	1,830,000	1,648,987	390,000	414,925	10,330,000	9,483,179	19,813,179
2010	1,890,000	1,594,088	405,000	400,300	11,005,000	9,003,318	20,008,318
2011	1,950,000	1,537,387	420,000	384,100	11,740,000	8,481,764	20,221,764
2012	2,035,000	1,459,388	440,000	366,250	9,290,000	7,897,057	17,187,057
2013	2,125,000	1,377,987	460,000	347,550	8,390,000	7,436,479	15,826,479
2014	2,200,000	1,292,988	480,000	326,850	9,430,000	7,018,050	16,448,050
2015	2,315,000	1,182,987	500,000	305,250	10,245,000	6,520,802	16,765,802
2016	2,435,000	1,067,238	525,000	282,750	11,110,000	5,974,302	17,084,302
2017	2,565,000	945,487	550,000	256,500	10,405,000	5,373,889	15,778,889
2018	2,695,000	817,238	570,000	234,500	11,315,000	4,819,140	16,134,140
2019	2,835,000	682,487	595,000	210,275	12,295,000	4,212,647	16,507,647
2020	2,985,000	540,738	615,000	184,988	13,350,000	3,549,865	16,899,865
2021	3,140,000	391,487	645,000	158,850	14,490,000	2,828,916	17,318,916
2022	3,300,000	234,488	675,000	129,825	15,695,000	2,043,661	17,738,661
2023	1,635,000	69,488	705,000	99,450	5,907,106	4,289,931	10,197,037
2024	-	-	735,000	67,725	3,399,611	4,243,364	7,642,975
2025	-	-	770,000	34,650	3,499,720	4,333,930	7,833,650
2026	-	-	-	-	2,799,579	4,423,671	7,223,250
2027	-	-	-	-	2,866,540	4,496,210	7,362,750
2028	-	-	-	-	2,215,000	477,250	2,692,250
2029	-	-	-	-	2,325,000	366,500	2,691,500
2030	-	-	-	-	2,440,000	250,250	2,690,250
2031	-	-	-	-	2,565,000	128,250	2,693,250
	40,410,000	20,071,226	10,575,000	5,524,250	213,757,556	138,570,862	352,328,418
Less current	995,000	-	355,000	-	7,890,000	-	7,890,000
	<u>\$ 39,415,000</u>	<u>\$ 20,071,226</u>	<u>\$ 10,220,000</u>	<u>\$ 5,524,250</u>	<u>\$ 205,867,556</u>	<u>\$ 138,570,862</u>	<u>\$ 344,438,418</u>

EUGENE WATER & ELECTRIC BOARD
WATER SYSTEM

LONG-TERM BONDED DEBT AND INTEREST PAYMENT REQUIREMENTS, INCLUDING CURRENT PORTION
YEAR ENDED DECEMBER 31, 2005

	Revenue Bonds Refunding 1997 Series 11-4-97		Revenue Bonds 2000 Series 1-1-00		Revenue Bonds 2002 Series 7-16-02		Revenue Bonds Refunding 2005 Series 7-26-05	
	Principal	Interest	Principal	Interest	Principal	Interest	Principal	Interest
2006	\$ 905,000	\$ 41,178	\$ -	\$ 101,870	\$ -	\$ 406,101	\$ -	\$ 510,269
2007	-	-	450,000	101,870	460,000	406,101	-	532,455
2008	-	-	470,000	1,200,698	470,000	393,451	-	532,455
2009	-	-	495,000	1,176,023	490,000	378,764	-	532,455
2010	-	-	520,000	1,149,788	505,000	362,839	-	532,455
2011	-	-	-	-	525,000	345,164	415,000	532,455
2012	-	-	-	-	545,000	326,264	430,000	517,930
2013	-	-	-	-	570,000	305,826	445,000	502,880
2014	-	-	-	-	595,000	283,596	460,000	487,305
2015	-	-	-	-	620,000	259,796	475,000	470,055
2016	-	-	-	-	645,000	234,221	500,000	451,055
2017	-	-	-	-	675,000	206,809	520,000	426,055
2018	-	-	-	-	710,000	178,121	545,000	400,055
2019	-	-	-	-	740,000	147,059	570,000	372,805
2020	-	-	-	-	780,000	113,759	600,000	344,305
2021	-	-	-	-	815,000	77,879	630,000	320,305
2022	-	-	-	-	855,000	40,185	655,000	295,105
2023	-	-	-	-	-	-	675,000	268,905
2024	-	-	-	-	-	-	705,000	241,230
2025	-	-	-	-	-	-	735,000	212,149
2026	-	-	-	-	-	-	765,000	181,830
2027	-	-	-	-	-	-	800,000	148,552
2028	-	-	-	-	-	-	835,000	113,753
2029	-	-	-	-	-	-	870,000	77,430
2030	-	-	-	-	-	-	910,000	39,585
	905,000	41,178	1,935,000	3,730,249	10,000,000	4,465,935	12,540,000	9,043,833
Less current	905,000	-	-	-	-	-	-	-
	\$ -	\$ 41,178	\$ 1,935,000	\$ 3,730,249	\$ 10,000,000	\$ 4,465,935	\$ 12,540,000	\$ 9,043,833

**EUGENE WATER & ELECTRIC BOARD
WATER SYSTEM**

**LONG-TERM BONDED DEBT AND INTEREST PAYMENT REQUIREMENTS, INCLUDING CURRENT PORTION
YEAR ENDED DECEMBER 31, 2005**

Total Water System Payments			
	Principal	Interest	Totals
2006	\$ 905,000	\$ 1,059,418	\$ 1,964,418
2007	910,000	1,040,426	1,950,426
2008	940,000	2,126,604	3,066,604
2009	985,000	2,087,242	3,072,242
2010	1,025,000	2,045,082	3,070,082
2011	940,000	877,619	1,817,619
2012	975,000	844,194	1,819,194
2013	1,015,000	808,706	1,823,706
2014	1,055,000	770,901	1,825,901
2015	1,095,000	729,851	1,824,851
2016	1,145,000	685,276	1,830,276
2017	1,195,000	632,864	1,827,864
2018	1,255,000	578,176	1,833,176
2019	1,310,000	519,864	1,829,864
2020	1,380,000	458,064	1,838,064
2021	1,445,000	398,184	1,843,184
2022	1,510,000	335,290	1,845,290
2023	675,000	268,905	943,905
2024	705,000	241,230	946,230
2025	735,000	212,149	947,149
2026	765,000	181,830	946,830
2027	800,000	148,552	948,552
2028	835,000	113,753	948,753
2029	870,000	77,430	947,430
2030	910,000	39,585	949,585
	25,380,000	17,281,195	42,661,195
Less current	905,000	-	905,000
	<u>\$ 24,475,000</u>	<u>\$ 17,281,195</u>	<u>\$ 41,756,195</u>

AUDIT COMMENTS

(DISCLOSURES AND COMMENTS REQUIRED BY STATE REGULATIONS)

Oregon Administrative Rules 162-10-050 through 162-10-320, the *Minimum Standards for Audits of Oregon Municipal Corporations*, prescribed by the Secretary of State in cooperation with the Oregon State Board of Accountancy, enumerate the financial statements, schedules, comments and disclosures required in audit reports. The required financial statements and schedules are set forth in preceding sections of this report. Required comments and disclosures related to the audit of such statements and schedules are set forth following.

**REPORT OF INDEPENDENT CERTIFIED PUBLIC ACCOUNTANTS ON THE EUGENE
WATER AND ELECTRIC BOARD'S, COMPLIANCE AND CERTAIN ITEMS
BASED ON AN AUDIT OF FINANCIAL STATEMENTS PERFORMED IN
ACCORDANCE WITH OREGON AUDITING STANDARDS**

January 26, 2006

To the Board of Commissioners
Eugene Water & Electric Board

We have audited the accompanying financial statements of the Electric System and Water System of Eugene Water and Electric Board ("Board") as of and for the year ended December 31, 2005 and have issued our report thereon dated January 26, 2006. We conducted our audit in accordance with auditing standards generally accepted in the United States of America and the provisions of the Minimum Standards for Audits of Oregon Municipal Corporations, prescribed by the Secretary of State. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement.

Compliance

As part of obtaining reasonable assurance about whether the Board's financial statements are free of material misstatement, we performed tests of its compliance with certain provisions of laws, regulations, contracts and grants, including provisions of Oregon Revised Statutes as specified in Oregon Administrative Rules OAR 162-10-000 to 162-10-330, as set forth below, noncompliance with which could have a direct and material effect on the determination of financial statement amounts:

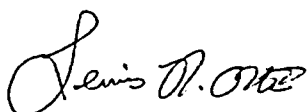
- The accounting records and related internal control structure.
- The amount and adequacy of collateral pledged by depositories to secure the deposit of public funds.
- The requirements relating to debt.
- The requirements relating to insurance and fidelity bond coverage.
- The appropriate laws, rules and regulations pertaining to programs funded wholly or partially by other governmental agencies.
- The statutory requirements pertaining to the investment of public funds.
- The requirements pertaining to the awarding of public contracts and the construction of public improvements.

However, providing an opinion on compliance with those provisions was not an objective of our audit and, accordingly, we do not express such an opinion. The results of our test disclosed no instances of noncompliance that are required to be reported under Minimum Standards for Audits of Oregon Municipal Corporations, prescribed by the Secretary of State.

Internal Control Over Financial Reporting

In planning and performing our audit, we considered the Board's internal control over financial reporting in order to determine our auditing procedures for the purpose of expressing our opinion on the financial statements and not to provide assurance on the internal control over financial reporting. Our consideration of the internal control over financial reporting would not necessarily disclose all matters in the internal control that might be material weaknesses. A material weakness is a condition in which the design or operation of one or more of the internal control components does not reduce to a relatively low level the risk that misstatements in amounts that would be material in relation to the financial statements being audited may occur and not be detected within a timely period by employees in the normal course of performing their assigned functions. We noted no matters involving the internal control over financial reporting and its operations that we consider to be material weaknesses.

This report is intended for the information and use of management, Board of Directors and the Secretary of State, Division of Audits, of the State of Oregon. However, this report is a matter of public record and its distribution is not limited.

A handwritten signature in cursive script, appearing to read "Lewis D. O'Neil".

For Moss Adams LLP
Certified Public Accountants