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

FORM 10-K

[X] Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended December 31, 2008

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	Exact name of registrant as specified in its charter; State or other jurisdiction of incorporation or organization	IRS Employer Identification No.
1-5152	**PACIFICORP** **(An Oregon Corporation)** **825 N.E. Multnomah Street** **Portland, Oregon 97232** **503-813-5000**	**93-0246090**

Securities registered pursuant to Section 12(b) of the Act: None
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 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, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☒ Smaller reporting company ☐

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

As of January, 31, 2009, there were 357,060,915 shares of common stock outstanding. All shares of outstanding common stock are indirectly owned by MidAmerican Energy Holdings Company, 666 Grand Avenue, Des Moines, Iowa.

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Forward-Looking Statements

This report contains statements that do not directly or exclusively relate to historical facts. These statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Forward-looking statements can typically be identified by the use of forward-looking words, such as "may," "could," "project," "believe," "anticipate," "expect," "estimate," "continue," "intend," "potential," "plan," "forecast" and similar terms. These statements are based upon PacifiCorp's current intentions, assumptions, expectations and beliefs and are subject to risks, uncertainties and other important factors. Many of these factors are outside PacifiCorp's control and could cause actual results to differ materially from those expressed or implied by PacifiCorp's forward-looking statements. These factors include, among others:

- general economic, political and business conditions in the jurisdictions in which PacifiCorp operates;
- changes in governmental, legislative or regulatory requirements affecting PacifiCorp or the electric utility industry, including limits on the ability of public utilities to recover income tax expense in rates, such as Oregon Senate Bill 408 ("SB 408");
- changes in, and compliance with, environmental laws, regulations, decisions and policies, including those addressing climate change, that could increase operating and capital improvement costs, reduce plant output and delay plant construction;
- the outcome of general rate cases and other proceedings conducted by regulatory commissions or other governmental and legal bodies;
- changes in economic, industry or weather conditions, as well as demographic trends, that could affect customer growth and usage or supply of electricity;
- 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 the cost, feasibility and eventual outcome of hydroelectric relicensing proceedings, that could have a significant impact on electric capacity and cost and on PacifiCorp's ability to generate electricity;
- changes in prices and availability for both purchases and sales of wholesale electricity, coal, natural gas, other fuel sources and fuel transportation that could have a significant impact on generation capacity and energy costs;
- the financial condition and creditworthiness of PacifiCorp's significant customers and suppliers;
- changes in business strategy or development plans;
- availability, terms and deployment of capital, including severe reductions in demand for investment-grade commercial paper, debt securities and other sources of debt financing and volatility in the London Interbank Offered Rate ("LIBOR"), the base interest rate for PacifiCorp's credit facilities;
- changes in PacifiCorp's credit ratings;
- performance of PacifiCorp's generating facilities, including unscheduled outages or repairs;
- the impact of derivative instruments used to mitigate or manage volume, price and interest rate risk, including increased cash collateral requirements, changes in the commodity prices, interest rates and other conditions that affect the value of the derivatives;
- the impact of increases in health care costs and changes in interest rates, mortality, morbidity, investment performance and legislation on pension and other postretirement benefits expense and funding requirements;
- unanticipated construction delays, changes in costs, receipt of required permits and authorizations, ability to fund capital projects and other factors that could affect future generating facilities and infrastructure additions;
- the impact of new accounting pronouncements or changes in current accounting estimates and assumptions on financial results;

- other risks or unforeseen events, including litigation and 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 PacifiCorp's filings with the United States Securities and Exchange Commission (the "SEC") or in other publicly disseminated written documents.

Further details of the potential risks and uncertainties affecting PacifiCorp are described in its filings with the SEC, including Item 1A and other discussions contained in this Form 10-K. PacifiCorp undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The foregoing review of factors should not be construed as exclusive.

PART I

ITEM 1. BUSINESS

General

PacifiCorp, which includes PacifiCorp and its subsidiaries, is a United States regulated electric company serving 1.7 million retail customers, including residential, commercial, industrial and other customers in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp owns, or has interests in, 74 thermal, hydroelectric, wind-powered and geothermal generating facilities, with a net owned capacity of 10,188 megawatts ("MW"). PacifiCorp also owns, or has interests in, electric transmission and distribution assets, and transmits electricity through approximately 15,800 miles of transmission lines. PacifiCorp also buys and sells electricity on the wholesale market with public and private utilities, energy marketing companies and incorporated municipalities as a result of excess electricity generation or other system balancing activities. PacifiCorp is subject to comprehensive state and federal regulation. PacifiCorp's subsidiaries support its electric utility operations by providing coal-mining facilities and services and environmental remediation services. PacifiCorp is a consolidated subsidiary of MidAmerican Energy Holdings Company ("MEHC"), a holding company based in Des Moines, Iowa, owning subsidiaries that are principally engaged in energy businesses. MEHC is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway"). MEHC controls substantially all of PacifiCorp's voting securities, which include both common and preferred stock.

Berkshire Hathaway Equity Commitment

On March 1, 2006, MEHC and Berkshire Hathaway entered into an Equity Commitment Agreement (the "Berkshire Equity Commitment") pursuant to which Berkshire Hathaway has agreed to purchase up to $3.5 billion of MEHC's common equity upon any requests authorized from time to time by MEHC's Board of Directors. The proceeds of any such equity contribution shall only be used by MEHC for the purpose of (i) paying when due MEHC's debt obligations and (ii) funding the general corporate purposes and capital requirements of MEHC's regulated subsidiaries, including PacifiCorp. Berkshire Hathaway will have up to 180 days to fund any such request in increments of at least $250 million pursuant to one or more drawings authorized by MEHC's Board of Directors. The funding of each drawing will be made by means of a cash equity contribution to MEHC in exchange for additional shares of MEHC's common stock. PacifiCorp has no right to make or to cause MEHC to make any equity contribution requests. The Berkshire Equity Commitment expires on February 28, 2011.

Operations

PacifiCorp delivers electricity to customers in Utah, Wyoming and Idaho under the trade name Rocky Mountain Power and to customers in Oregon, Washington and California under the trade name Pacific Power. PacifiCorp's electric generation, commercial and energy trading, and coal-mining functions are operated under the trade name PacifiCorp Energy. 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 generating facilities. This electricity, together with electricity purchased on the wholesale market, is then transmitted via a grid of transmission lines throughout PacifiCorp's six-state service area and the Western United States. The electricity is then transformed to lower voltages and delivered to customers through PacifiCorp's distribution system.

PacifiCorp's primary goal is to provide safe, reliable electricity to its customers at a reasonable cost. In return, PacifiCorp expects that all prudently incurred costs to provide such service will be included as allowable costs for state ratemaking purposes, and PacifiCorp will be allowed an opportunity to earn a reasonable return on its investments.

PacifiCorp has historically experienced growth in retail loads. However, beginning in the fourth quarter of 2008, certain customer usage levels began to decline due to the effects of current economic conditions in the United States and around the world. This declining usage trend may continue in 2009. PacifiCorp seeks to manage growth in its customer demand through the construction and purchase of new cost-effective, environmentally prudent and efficient sources of power supply and through demand response and energy efficiency programs. During 2008, PacifiCorp added the 520-MW Chehalis natural gas-fired generating plant and placed in service 382 MW of wind-powered generating facilities to help meet its retail load growth and replace expiring wholesale supply contracts. PacifiCorp continues to pursue other cost-effective wind-powered generating facilities.

As part of the Energy Gateway Transmission Expansion Project discussed further at "Transmission and Distribution" below, PacifiCorp has an investment plan to build approximately 2,000 miles of new high-voltage transmission lines at an estimated cost exceeding $6.1 billion. This plan includes projects that will address customer load growth, improve system reliability and deliver energy from new wind-powered and other renewable generating resources throughout PacifiCorp's six-state service area and the Western United States.

The above-mentioned generation and transmission system expansions will also facilitate meeting the commitments made to state regulatory commissions as a result of MEHC's acquisition of PacifiCorp.

Employees

As of December 31, 2008, PacifiCorp, together with its subsidiaries, had 6,596 employees, 61% of which were covered by union contracts, principally with the International Brotherhood of Electrical Workers, the Utility Workers Union of America, the International Brotherhood of Boilermakers and the United Mine Workers of America.

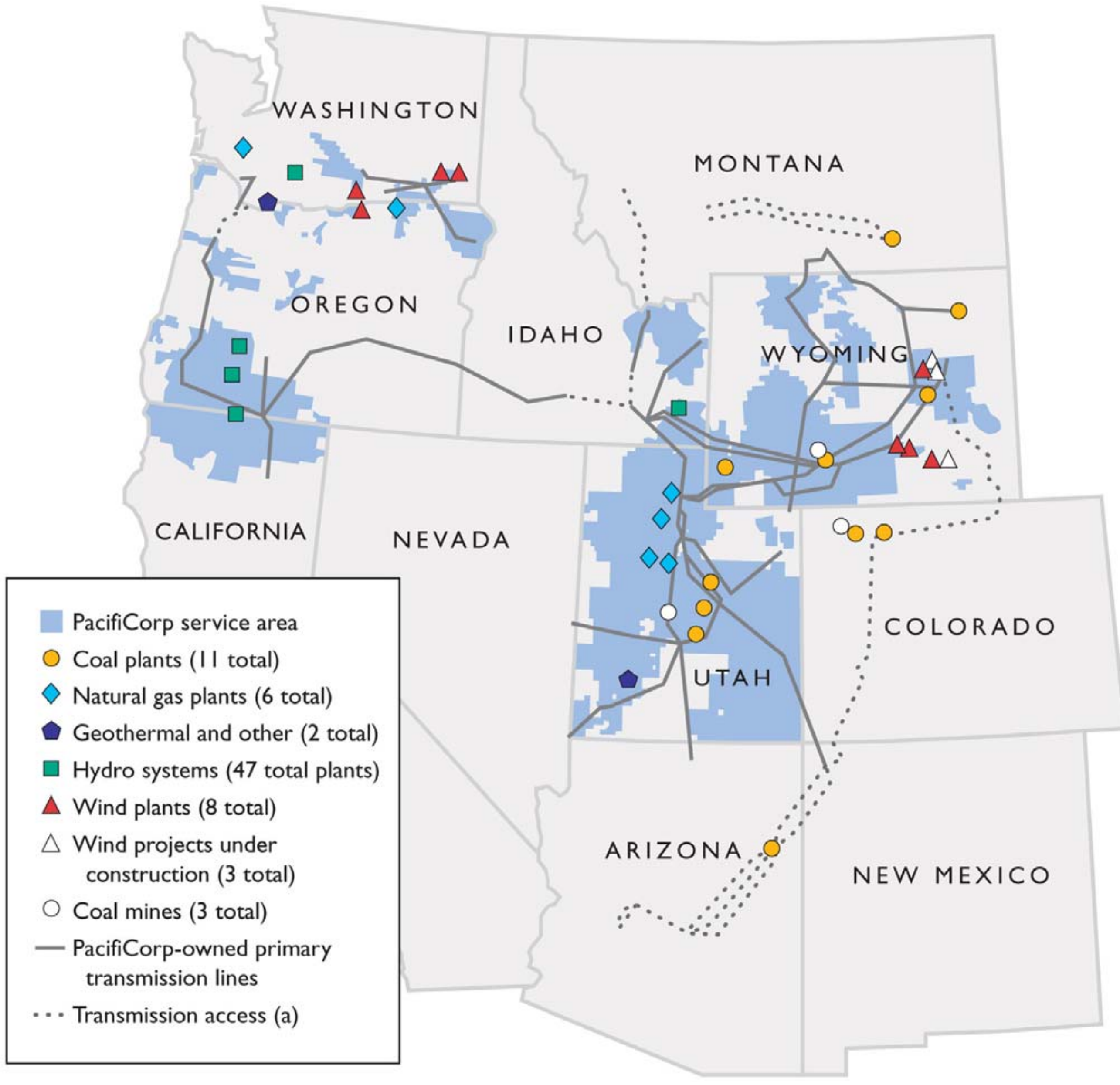
Fiscal Year-End Change

In May 2006, the PacifiCorp Board of Directors elected to change PacifiCorp's fiscal year-end from March 31 to December 31. As a result, the Consolidated Statements of Operations include the audited nine-month transition period ended December 31, 2006.

Service Territories

PacifiCorp serves 1.7 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 urban, manufacturing and government service centers. No single segment of the economy dominates the service territory, which helps mitigate 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, agriculture 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, technology and primary metals being the largest industrial sectors.

The following map highlights PacifiCorp's retail service territory, generating facility locations and PacifiCorp's primary transmission lines as of December 31, 2008. PacifiCorp's generating facilities are interconnected through PacifiCorp's own transmission lines or by contract through transmission lines owned by others.



(a) Access to other entities' transmission lines through wheeling arrangements.

The percentages of electricity sold to retail customers by jurisdiction were as follows:

	Years Ended December 31, 2008	Years Ended December 31, 2007	Nine-Month Period Ended December 31, 2006
Utah	42%	42%	41%
Oregon	26	26	26
Wyoming	17	16	16
Washington	7	8	8
Idaho	6	6	7
California	2	2	2
	100%	100%	100%

PacifiCorp receives authorization from state public utility commissions to serve areas within each state. This authorization is perpetual until withdrawn. In addition, PacifiCorp has received franchises that permit it to provide electric service to customers inside incorporated areas within the states. The average term of these franchises is approximately 30 years, although their terms range from five years to indefinite. PacifiCorp must renew franchises as they 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. However, PacifiCorp vigorously challenges attempts from individuals and governmental agencies to undertake forced takeover of portions of its service territory.

Customers

Electricity sold to retail customers and the average number of retail customers, by class of customer, were as follows:

	Years Ended December 31, 2008		Years Ended December 31, 2007		Nine-Month Period Ended December 31, 2006	
Gigawatt hours ("GWh") sold:						
Residential	16,222	24%	15,975	24%	11,158	22%
Commercial	16,055	24	15,951	24	11,713	24
Industrial	21,495	32	20,892	31	15,719	32
Other	590	1	572	1	439	1
Total retail	54,362	81	53,390	80	39,029	79
Wholesale	12,345	19	13,724	20	10,284	21
Total GWh sold	66,707	100%	67,114	100%	49,313	100%
Average number of retail customers (in thousands):						
Residential	1,458	86%	1,441	86%	1,415	86%
Commercial	210	12	205	12	200	12
Industrial	34	2	34	2	34	2
Other	4	-	4	-	4	-
Total	1,706	100%	1,684	100%	1,653	100%
Retail customers:						
Average usage per customer (kilowatt hours)	31,863		31,712		23,607	
Average revenue per customer	$ 2,021		$ 1,931		$ 1,358	
Revenue per kilowatt hour	6.3¢		6.1¢		5.8¢	

PacifiCorp experienced growth in retail sales volumes in its service territories during the years ended December 31, 2008 and 2007. However, for 2009, PacifiCorp expects the recent recessionary economic conditions may reduce its retail sales volumes in the states of Utah, Oregon, Washington and California. Growth is expected to continue in Wyoming and Idaho. Retail sales volumes depend on factors such as economic conditions, including the timing of recovery from the current economic recession, population growth, consumer trends, voluntary and mandated conservation efforts, weather, and technology and price changes.

Seasonality

Peak customer demand is typically highest in the summer across PacifiCorp's service territory when air conditioning and irrigation systems are heavily used. The service area also has a winter peak, which is typically lower than the summer peak, and primarily is due to heating requirements in the western portion of its service territory.

For residential customers, within a given year, weather conditions are the dominant cause of usage variations from normal seasonal patterns. Strong Utah residential growth and increased installation and use of central air conditioning systems have contributed to increased summer peak load growth over the past few years. During the year ended December 31, 2008, PacifiCorp's peak load was 9,501 MW in the summer and 9,176 MW in the winter. Peak load represents the highest load on a given day and at a given hour.

Retail Competition

During the year ended December 31, 2008, PacifiCorp continued to operate its retail business under state regulation, which generally prohibits retail competition. However, under a 1999 Oregon law, certain PacifiCorp commercial and industrial customers in Oregon have the right to choose alternative electricity service suppliers. As a result of this law, a group of customers having a total load of approximately 12 average MW have chosen service from suppliers other than PacifiCorp. PacifiCorp does not expect this competitive program to have a material effect on its financial results during the year ending December 31, 2009.

In addition to Oregon's program permitting limited retail competition, others in PacifiCorp's service territories are seeking to have a choice of suppliers, exploring options to build their own generation or co-generation facilities, 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.

Power and Fuel Supply

Overview

The following table shows the percentage of PacifiCorp's total energy supplied by energy source:

	Years Ended December 31,		Nine-Month Period Ended December 31,
	2008	2007	2006
Coal	65%	64%	62%
Natural gas	12	11	7
Hydroelectric	5	5	6
Other	2	1	1
Total energy generated	84	81	76
Energy purchased–long-term contracts	5	5	7
Energy purchased–short-term contracts and other	11	14	17
	100%	100%	100%

The percentage of PacifiCorp's energy requirements generated by energy source varies from year to year and is subject to numerous operational and economic factors such as planned and unplanned outages, fuel availability, price and transportation costs, weather-related impacts, environmental considerations and the market price of electricity. When factors for one source of generation are unfavorable, PacifiCorp may place more reliance on the other sources of generation. For example, the amount of electricity PacifiCorp is able to generate from its hydroelectric facilities depends on a number of factors, including snow-pack in the mountains upstream of its hydroelectric facilities, reservoir storage, precipitation in its watersheds, generating unit 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 low cost hydroelectric facilities. When these factors are unfavorable, PacifiCorp must increase its reliance on more expensive coal and natural gas-fired facilities and purchased electricity.

In determining whether to dispatch its natural gas-fired generating facilities, PacifiCorp considers, among other things, its operational requirements to balance electricity supply and demand and the current spark spread. Spark spread is the difference between the wholesale market price of electricity at any given hour and the cost to convert the fuel to electricity for the generating facility.

The following presents certain information concerning PacifiCorp's generating facilities as of December 31, 2008:

	Location	Energy Source	Installed	Facility Net Capacity (MW) [1]	Net MW Owned [1]
COAL:					
Jim Bridger [2]	Rock Springs, WY	Coal	1974-1979	2,120	1,414
Hunter Nos. 1, 2 and 3 [2]	Castle Dale, UT	Coal	1978-1983	1,320	1,122
Huntington	Huntington, UT	Coal	1974-1977	895	895
Dave Johnston	Glenrock, WY	Coal	1959-1972	762	762
Naughton	Kemmerer, WY	Coal	1963-1971	700	700
Cholla No. 4	Joseph City, AZ	Coal	1981	380	380
Wyodak [2]	Gillette, WY	Coal	1978	335	268
Carbon	Castle Gate, UT	Coal	1954-1957	172	172
Craig Nos. 1 and 2 [2]	Craig, CO	Coal	1979-1980	856	165
Colstrip Nos. 3 and 4 [2]	Colstrip, MT	Coal	1984-1986	1,480	148
Hayden Nos. 1 and 2 [2]	Hayden, CO	Coal	1965-1976	446	78
				9,466	6,104
NATURAL GAS:					
Lake Side	Vineyard, UT	Natural gas/Steam	2007	548	548
Currant Creek	Mona, UT	Natural gas/Steam	2005-2006	540	540
Chehalis [3]	Chehalis, WA	Natural gas/Steam	2003	520	520
Hermiston [2]	Hermiston, OR	Natural gas/Steam	1996	474	237
Gadsby Steam	Salt Lake City, UT	Natural gas	1951-1952	235	235
Gadsby Peakers	Salt Lake City, UT	Natural gas	2002	120	120
Little Mountain	Ogden, UT	Natural gas	1972	14	14
				2,451	2,214
HYDROELECTRIC: [4][6]					
Lewis River System [7]	WA	Hydroelectric	1931-1958	578	578
North Umpqua River System [8]	OR	Hydroelectric	1950-1956	200	200
Klamath River System [9]	CA, OR	Hydroelectric	1903-1962	170	170
Bear River System [10]	ID, UT	Hydroelectric	1908-1984	105	105
Rogue River System [11]	OR	Hydroelectric	1912-1957	52	52
Minor hydroelectric facilities	Various	Hydroelectric	1895-1986	53	53
				1,158	1,158
WIND: [6]					
Marengo	Dayton, WA	Wind	2007	140	140
Leaning Juniper 1	Arlington, OR	Wind	2006	101	101
Glenrock	Glenrock, WY	Wind	2008	99	99
Seven Mile Hill	Medicine Bow, WY	Wind	2008	99	99
Goodnoe Hills	Goldendale, WA	Wind	2008	94	94
Marengo II	Dayton, WA	Wind	2008	70	70
Foote Creek [2]	Arlington, WY	Wind	1997	41	33
Seven Mile Hill II	Medicine Bow, WY	Wind	2008	20	20
				664	656
OTHER: [6]					
Blundell	Milford, UT	Geothermal	1984, 2007	34	34
Camas Co-Gen	Camas, WA	Black liquor	1996	22	22
				56	56
Total available generating capacity				13,795	10,188
PROJECTS UNDER CONSTRUCTION/DEVELOPMENT: [5]					
High Plains	McFadden, WY	Wind	2009	99	99
Rolling Hills	Glenrock, WY	Wind	2009	99	99
Glenrock III	Glenrock, WY	Wind	2009	39	39
				237	237

(1) Facility net capacity (MW) represents the total capability of a generating unit as demonstrated by actual operating or test experience, less power generated and used for auxiliaries and other station uses, and is determined using average annual temperatures. Net MW owned indicates current legal ownership. For wind-powered generating facilities, nameplate ratings are used in place of facility net capacity. A generator's nameplate rating is its full-load capability (in MW) under normal operating conditions as defined by the manufacturer.
(2) For joint ownership percentage, refer to Note 4 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.
(3) PacifiCorp acquired the 520-MW natural gas-fired generating plant located in Chehalis, Washington, in September 2008.
(4) For information regarding the relicensing and decommissioning of certain of PacifiCorp's hydroelectric generating facilities, refer to "Hydroelectric Relicensing" and "Hydroelectric Decommissioning" below.
(5) The 99-MW Rolling Hills and 39-MW Glenrock III wind-powered generating facilities were placed in service during January 2009. The 99-MW High Plains wind-powered generating facility is expected to be complete by the end of 2009.
(6) All or some of the renewable energy attributes associated with generation from these generating facilities may be: (i) used in future years to comply with state or federal renewable portfolio standards ("RPS") or other regulatory requirements or (ii) sold to third parties in the form of renewable energy credits or other environmental commodities.
(7) The license for this facility is valid through May 2058.
(8) The license for this facility is valid through October 2038.
(9) The license for this facility was valid through February 2006 and it currently operates on annual licenses. Refer to Note 13 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for an update regarding hydroelectric relicensing for the Klamath River system.
(10) The license is valid through March 2024 for Cutler and through November 2033 for the Grace, Oneida and Soda hydroelectric generating facilities.
(11) The license is valid through December 2018 for Prospect No. 3 and through March 2038 for the Prospect Nos. 1, 2 and 4 hydroelectric generating facilities.

Coal

Coal-fired generating facilities account for 60% of PacifiCorp's total net owned generating capacity. Recoverable coal reserves as of December 31, 2008, based on PacifiCorp's most recent engineering studies, were as follows (in millions):

Location	Plant Served	Mining Method	Recoverable Tons
Craig, CO	Craig	Surface	47 (1)
Huntington & Castle Dale, UT	Huntington and Hunter	Underground	35 (2)
Rock Springs, WY	Jim Bridger	Surface	84 (3)
Rock Springs, WY	Jim Bridger	Underground	53 (3)
			219

(1) 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%.
(2) These coal reserves are leased by PacifiCorp and mined by a wholly owned subsidiary of PacifiCorp.
(3) 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 wholly owned subsidiary of PacifiCorp, has a two-thirds interest in the joint venture. The amount included above represents only PacifiCorp's two-thirds interest in the coal reserves.

These mines supplied 31% of PacifiCorp's total coal requirements during each of the years ended December 31, 2008 and 2007 and the nine-month period ended December 31, 2006. The remaining coal requirements are acquired through long- and short-term third-party contracts. PacifiCorp's mines are located adjacent to many of its coal-fired generating facilities, which significantly reduces overall transportation costs included in fuel expense.

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. PacifiCorp believes that the coal reserves available to the Craig, Huntington, Hunter and Jim Bridger coal-fired generating facilities, together with coal available under both long- and short-term contracts with external suppliers to supply its remaining generating facilities, will be substantially sufficient to provide these facilities with fuel for their currently expected useful lives. To meet applicable standards, PacifiCorp blends coal mined at its owned mines with contracted coal and utilizes emission reduction technologies for controlling sulfur dioxide and other emissions.

During the year ended December 31, 2008, PacifiCorp-owned generating facilities held sufficient sulfur dioxide emission allowances to comply with the United States Environmental Protection Agency (the "EPA") Title IV requirements. The sulfur content of the coal reserves generally ranges from 0.30% to 1.3%, and the British thermal units value per pound of PacifiCorp's coal reserves ranges from 8,600 to 12,400.

Recoverability by surface mining methods typically ranges from 90% to 95%. Recoverability by underground mining techniques ranges from 50% to 70%. 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 only with the consent of the lessor 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.

Natural Gas

PacifiCorp's natural gas-fired generating facilities account for 22% of PacifiCorp's total net owned generating capacity. PacifiCorp uses natural gas as fuel for its combined- and simple-cycle natural gas-fired generating facilities. Oil and natural gas are also used for igniter fuel and to fuel generation for transmission support and standby purposes. PacifiCorp has developed a natural gas procurement strategy that addresses the need to economically hedge the estimated commodity risk (physical availability and price), transportation risk and storage risk associated with its forecasted natural gas requirements.

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 forecasted physical natural gas requirements 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 December 31, 2008, PacifiCorp had economically hedged 64% of its forecasted physical exposure and 94% of its forecasted financial exposure for 2009. For 2010, PacifiCorp currently has hedged 48% of its forecasted physical exposure and 85% of its forecasted financial exposure.

Hydroelectric

Hydroelectric generating facilities account for 11% of PacifiCorp's total net owned generating capacity. PacifiCorp operates the majority of its hydroelectric generating portfolio under long-term licenses from the Federal Energy Regulatory Commission (the "FERC") with terms of 30 to 50 years. Hydroelectric relicensing and the related environmental compliance requirements and litigation are subject to uncertainties. PacifiCorp expects that future costs relating to these matters will be significant and consist primarily of additional relicensing costs and capital expenditures. If licenses are not issued, significant decommissioning costs may be incurred. Electricity generation reductions may also result from additional environmental requirements. As of December 31, 2008 and 2007, PacifiCorp had $57 million and $89 million, respectively, in costs for ongoing hydroelectric relicensing included in construction work-in-progress within property, plant and equipment, net in the Consolidated Balance Sheets. For a further discussion of PacifiCorp's hydroelectric relicensing and decommissioning activities, refer to "Hydroelectric Relicensing" and "Hydroelectric Decommissioning" below.

Wind and Other Renewable Resources

PacifiCorp is pursuing renewable resources as viable, economic and environmentally prudent means of generating electricity, achieving emission reduction targets and for compliance with RPS. The benefits of energy from renewable resources include low to no emissions and typically little or no fossil fuel requirements. PacifiCorp may from time to time purchase or sell some of the environmental attributes, such as renewable energy credits or other environmental commodities from its renewable generating facilities, or from comparable third party renewable resources, to meet current or future RPS or other regulatory requirements or for other purposes. The intermittent nature of some renewable resources, such as wind, is complemented by PacifiCorp's other generating resources, such as coal-fired, natural gas-fired and hydroelectric generation. These complementary generating resources, as well as wind-powered generating resource curtailment capabilities, are important to integrating intermittent wind-powered generating resources into the electric system. PacifiCorp has qualifying wind-powered generating facilities that are eligible for federal renewable electricity production tax credits ("PTCs") for 10 years from the date that the facilities were placed in service. In February 2009, legislation was passed extending the date by which such facilities must be placed in service to be eligible for PTCs to December 31, 2012.

Wholesale Sales and Purchased Electricity

In addition to its portfolio of generating facilities, PacifiCorp purchases electricity in the wholesale markets to meet its retail load and long-term wholesale sales obligations for system balancing requirements and to enhance the efficient use of its generating capacity over the long-term. Generation can vary with the levels of outages, hydroelectric and wind-powered generating conditions, operational factors and transmission constraints. Retail load can vary 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 facilities. 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. Many of PacifiCorp's purchased electricity contracts have fixed-price components, which provide some protection against price volatility.

Historically, PacifiCorp has been able to purchase electricity from utilities in the Western United States for its own requirements. Delivery of these purchases is 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 and wind-powered 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.

Future Generation and Conservation

Integrated Resource Plan

As required by certain state regulations, PacifiCorp uses an Integrated Resource Plan ("IRP") 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 IRP 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 IRP is a coordinated effort with stakeholders in each of the six states where PacifiCorp operates. PacifiCorp files its IRP on a biennial basis.

In May 2007, PacifiCorp released its 2007 IRP, which identified a need for approximately 3,171 MW of additional resources by summer 2016 to satisfy the difference between projected retail load obligations and owned or contracted resources. PacifiCorp plans to meet this need through demand response and energy efficiency programs; the construction or purchase of additional generation, including cost-effective renewable energy, combined heat and power, and thermal generation; and wholesale electricity transactions to make up for the remaining difference between retail load obligations and owned or contracted resources.

In June and August 2008, PacifiCorp submitted to the state regulatory commissions a 2007 IRP update report reflecting revised planning assumptions. The need for additional resources by 2016 was essentially unchanged at 3,202 MW. Relative to the initial 2007 IRP, the planned resources to meet this need include a heavier reliance on energy efficiency measures. This need was reduced by 509 MW due to the September 2008 acquisition of the Chehalis plant. PacifiCorp's 2008 IRP is scheduled to be filed in Spring 2009, which will take into account recent declines in load and growth expectations.

Requests for Proposals

PacifiCorp has issued a series of separate requests for proposals ("RFPs"), each of which focuses on a specific category of resources consistent with the IRP. The IRP and the RFPs provide for the identification and staged procurement of resources in future years to achieve load/resource balance. As required by applicable laws and regulations, PacifiCorp files draft RFPs with the Utah Public Service Commission (the "UPSC"), the Oregon Public Utility Commission (the "OPUC") and the Washington Utilities and Transportation Commission (the "WUTC") prior to issuance to the market.

In February 2007, PacifiCorp filed a modified 2012 RFP (the "2012 RFP") in Utah for up to 1,700 MW of additional resources to become available beginning in 2012 through 2014. The 2012 RFP was approved by the UPSC and issued to the market in April 2007. In June 2007, proposals from qualifying bidders were received by commission-directed independent evaluators. These bids included various structures, ranging from purchase or lease of coal, natural gas and geothermal generating facilities to power purchase agreements. Due to lack of cost effective bids, the 2012 RFP did not result in any new resources.

In January 2008, PacifiCorp issued to the market a renewable resources RFP for resources less than 100 MW, or greater than 100 MW for a power purchase agreement with a term of less than five years, to become available no later than December 2009. In September 2008, PacifiCorp executed a power purchase agreement to purchase the entire output of the proposed 99-MW Three Buttes wind-powered generating plant located in Wyoming. The generation of the energy and associated renewable energy credits under this agreement are expected to commence in December 2009 and continue for a period of 20 years.

In February 2008, PacifiCorp filed an all-source 2008 RFP (the "2008 RFP") with the UPSC and the OPUC for base load, intermediate or third quarter summer peaking products to be delivered into PacifiCorp's system. The 2008 RFP seeks up to 2,000 MW of resources to become available beginning in 2012 through 2016. The 2008 RFP was approved by the OPUC and the UPSC and subsequently issued to the market in October 2008. Proposals were received from the market in December 2008. The proposals were evaluated and resulted in no cost effective proposals. As a result, the 2008 RFP was suspended and is expected to be reissued during 2009.

In April 2008, PacifiCorp filed its draft 2008R-1 renewable resources RFP (the "2008R-1 RFP") with the OPUC. The 2008R-1 RFP is a 500 MW request for renewable generation projects, with no single resource greater than 300 MW and on-line dates no later than December 31, 2011. The 2008R-1 RFP was approved by the OPUC in September 2008. Single renewable resource requests under 300 MW do not require approval from the UPSC. The 2008R-1 RFP was issued to the market in October 2008. Proposals were received from the market in December 2008 followed by an amendment issued in January 2009 to include new and updated proposals that are due in February 2009.

In addition to new generation resources, substantial transmission investments will be required to deliver energy to PacifiCorp's growing customer base and to enhance system reliability. Refer to "Transmission and Distribution" below.

Demand-side Management

PacifiCorp has provided a comprehensive set of demand-side management programs to its customers since the 1970s. The programs are designed to reduce energy consumption and more effectively manage when energy is used, including management of seasonal peak loads. Current programs offer services to customers such as energy engineering audits and information on how to improve the efficiency of their homes and businesses. To assist customers in investing in energy efficiency, PacifiCorp offers rebates or incentives encouraging the purchase and installation of high-efficiency equipment such as lighting, heating and cooling equipment, weatherization, motors, process equipment and systems, as well as incentives for efficient construction. Incentives are also paid to solicit participation in load management programs by residential, business and agricultural customers through programs such as PacifiCorp's residential and small commercial air conditioner load control program and irrigation equipment load control programs. Subject to random prudence reviews, state regulations allow for contemporaneous recovery of costs incurred for retail customer demand-side management programs and services through state-specific energy efficiency service charges paid by all retail electric customers. In addition to these retail customer demand-side management programs, PacifiCorp has load curtailment contracts with a number of large industrial customers that deliver up to 342 MW of load reduction when needed. Recovery for the costs associated with the large industrial load management program is determined through PacifiCorp's general rate case process. In 2008, $77 million was expended on the demand-side management programs in PacifiCorp's six-state service area, resulting in an estimated 395,000 megawatt hours ("MWh") of first-year energy savings and 338 MW of peak load management. Total demand-side load available for control in 2008, including both load management from the large industrial curtailment contracts and retail customer demand-side management programs, was approximately 680 MW.

Transmission and Distribution

PacifiCorp operates one balancing authority area in the western portion of its service territory, and one balancing authority area in the eastern portion of its service territory. A balancing authority area is a geographic area with electric systems that control generation to maintain schedules with other balancing authority areas and ensure reliable operations. In operating the balancing authority areas, PacifiCorp is responsible for continuously balancing electric supply and demand by dispatching generating resources and interchange transactions so that generation internal to the balancing authority area, plus net imported power, matches customer loads. PacifiCorp also schedules deliveries of energy over its transmission system in accordance with FERC requirements.

Electric transmission systems deliver energy from electric generators to distribution systems for final delivery to customers. During the year ended December 31, 2008, PacifiCorp delivered 66,707 GWh, net of line losses, of electricity to retail and wholesale customers in its two balancing authority areas.

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 Electricity Coordinating Council (the "WECC"). The map under "Service Territories" above shows PacifiCorp's primary transmission system.

As of December 31, 2008, PacifiCorp owned, or participated in, an electric transmission system consisting of approximately:

Nominal Voltage (In kilovolts) Transmission Lines	Miles
500	700
345	2,000
230	3,400
161	400
138	2,100
46 to 115	7,200
	15,800

PacifiCorp's electric transmission and distribution system included approximately 900 substations at December 31, 2008. PacifiCorp's transmission system, together with contractual rights on other transmission systems, enables PacifiCorp to integrate and access generating resources to meet its customer load requirements.

PacifiCorp has an investment plan, the Energy Gateway Transmission Expansion Project, to build approximately 2,000 miles of new high-voltage transmission lines primarily in Wyoming, Utah, Idaho, Oregon and the desert Southwest. The plan, with an estimated cost exceeding $6.1 billion, includes projects that will address customer load growth, improve system reliability and deliver energy from new wind-powered and other renewable generating resources throughout PacifiCorp's six-state service area and the Western United States. Certain transmission segments associated with this plan are expected to be placed in service beginning 2010, with other segments placed in service through 2018, depending on siting, permitting and construction schedules. Refer to "Federal Regulation" below for further discussion.

Substantially all of PacifiCorp's generating facilities 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 United States 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.

PacifiCorp's wholesale transmission services are regulated by the FERC under cost-based regulation subject to PacifiCorp's Open Access Transmission Tariff ("OATT"). In accordance with OATT, PacifiCorp offers several transmission services to wholesale customers:

- Network transmission service (guaranteed service that integrates generating resources to serve retail loads);
- Long- 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, which means that all potential customers are provided an equal opportunity to access the transmission system. PacifiCorp's transmission business is managed and operated independently from its energy marketing business, in accordance with the FERC Standards of Conduct.

For retail customers, transmission costs are not separated from, but rather are "bundled" with, generation and distribution costs in rates approved by state regulatory commissions. Refer to "State Regulation" and "Federal Regulation" below for further information.

General Regulation

PacifiCorp is subject to comprehensive governmental regulation that significantly influences its operating environment, prices charged to customers, capital structure, costs and its ability to recover costs.

State Regulation

Historically, state utility commissions have established service rates on a cost-of-service basis, which is designed to allow a utility an opportunity to recover its costs of providing services and to earn a reasonable return on its investment. A utility's cost of service generally reflects its allowed operating expenses, including operation and maintenance expense, depreciation expense and taxes. Some portion of margins earned on wholesale activities for electricity and capacity has historically been included to reduce the retail cost of service upon which retail rates are based. State utility commissions may adjust rates pursuant to a review of (i) a utility's revenues and expenses during a defined test period and (ii) the utility's level of investment. State utility commissions typically have the authority to review and change rates on their own initiative. States may initiate reviews at the request of a utility customer, a governmental agency or a representative of a group of customers. The utility and such parties, however, may agree with one another not to request a review of or changes to rates for a specified period of time.

The electric rates of PacifiCorp are generally based on the cost of providing traditional bundled service, including generation, transmission and distribution services. Historically, the state regulatory framework in PacifiCorp's service territory reflects specified power and fuel costs as part of bundled rates or incorporated power or fuel adjustment clauses in the utility's rates and tariffs. In states where PacifiCorp has power and fuel adjustment clauses, PacifiCorp is permitted periodic adjustments to recover such costs from customers, which provide protection against exposure to power and fuel cost changes.

Except for Oregon and Washington, PacifiCorp has an exclusive right to serve electricity customers within its service territories and, in turn, has the obligation to provide electric service to those customers. Under Oregon law, PacifiCorp has the exclusive right and obligation to provide electric distribution services to all customers within its allocated service territory; however, nonresidential customers have the right to choose alternative electricity service suppliers. The impact of these programs on PacifiCorp's financial results has not been material. In Washington, state law does not provide for exclusive service territory allocation. PacifiCorp's service territory in Washington is surrounded by other public utilities with whom PacifiCorp has from time to time entered into service area agreements under the jurisdiction of the WUTC. Some of PacifiCorp's hydroelectric generating facilities are licensed under the Oregon Hydroelectric Act.

The following table illustrates PacifiCorp's recovery mechanisms in each state jurisdiction in which PacifiCorp operates. Refer to "Liquidity and Capital Resources" in Item 7 of this Form 10-K for additional information regarding current rate filings.

State Regulator	Base Rate Test Period	Adjustment Mechanism [1]
Utah Public Service Commission	Forecasted or historical with known and measurable changes [2]	No separate recovery mechanisms.
Oregon Public Utility Commission	Forecasted	Annual transition adjustment mechanism ("TAM"), a mechanism for annual rate adjustments for forecasted net variable power costs; no true-up to actual net variable power costs.
		Renewable adjustment clause ("RAC") to recover the revenue requirement of new renewable resources and associated transmission that are not reflected in general rates.
		Annual SB 408 true-up of taxes authorized to be collected in rates compared to taxes paid by PacifiCorp, as defined by Oregon statute and administrative rules.
Wyoming Public Service Commission (the "WPSC")	Forecasted or historical with known and measurable changes [2]	Power cost adjustment mechanism ("PCAM") based on forecasted net power costs, later trued-up to actual net power costs. Subject to dead bands and customer sharing.
Washington Utilities and Transportation Commission	Historical with known and measurable changes	Deferral mechanism of costs for up to 24 months of new base load generation resources that qualify under the state's emissions performance standard and are not reflected in general rates.
Idaho Public Utilities Commission (the "IPUC")	Historical	PacifiCorp has requested approval of an energy cost adjustment mechanism ("ECAM") to recover the difference between base power costs set during a general rate case and actual power costs. The application is currently pending before the Commission.
California Public Utilities Commission (the "CPUC")	Forecasted	Post test-year adjustment mechanism for major capital additions ("PTAM – capital additions"), a mechanism that allows for rate adjustments outside of the context of a traditional rate case for the revenue requirement associated with capital additions exceeding $50 million on a total-company basis. Filed as eligible capital additions are placed into service.
		Post test-year adjustment mechanism for attrition ("PTAM – attrition"), a mechanism that allows for an annual adjustment to costs other than net variable power costs tied to the Consumer Price Index minus a 0.5% productivity offset.
		Energy cost adjustment clause ("ECAC") that allows for an annual update to actual and forecasted net variable power costs.

(1) Margins earned on wholesale sales for energy and capacity have historically been included as a component of retail cost of service upon which retail rates are based.

(2) PacifiCorp has relied on both historical test periods with known and measurable adjustments and forecasted test periods. The WPSC has never issued a final ruling on its preference between a historical or forecasted test period.

State Regulatory Actions

PacifiCorp pursues a regulatory program in all states, with the objective of keeping rates closely aligned to ongoing costs. Refer to "Liquidity and Capital Resources" in Item 7 of this Form 10-K for a state-by-state update.

Federal Regulation

The FERC is an independent agency with broad authority to implement provisions of the Federal Power Act and the Energy Policy Act and other federal statutes. The FERC regulates rates for interstate sales of electricity at wholesale, transmission of electric power, including pricing and expansion of the transmission system; utility holding companies; accounting; securities issuances; and other matters, including construction and operation of hydroelectric projects, and has the enforcement authority to assess civil penalties of up to $1 million per day per violation of rules, regulations and orders issued under the Federal Power Act. PacifiCorp has implemented programs to be fully compliant with the FERC regulations described below, including having instituted compliance monitoring procedures.

Wholesale Electricity and Capacity

The FERC regulates PacifiCorp's rates charged to wholesale customers for electricity, capacity and transmission services. Most of PacifiCorp's electric wholesale sales and purchases take place under market-based rate pricing allowed by the FERC and are therefore subject to market volatility.

The FERC conducts a triennial review of PacifiCorp's market-based rate pricing authority in accordance with the filing schedule established by the FERC in Order No. 697. Each utility must demonstrate the lack of generation market power in order to charge market-based rates for sales of wholesale electricity and capacity in their respective balancing authority areas. PacifiCorp's next triennial filing is due in June 2010. Under the FERC's market-based rules, PacifiCorp must also file a notice of change in status upon the ownership or control of an additional 100 MW of incremental generation. Following the filing by PacifiCorp of a change in status notice relating to new generation, the FERC in November 2007 confirmed that PacifiCorp does not have market power and may continue to charge market-based rates. In October 2008, PacifiCorp filed a change in status notice, which is pending, related to its acquisition of the 520-MW Chehalis natural gas-fired generating facility and the expected commercial operation of several new PacifiCorp wind-powered generating facilities. Although PacifiCorp submitted studies to support a FERC conclusion consistent with its precedent that PacifiCorp continues to lack generation market power in all relevant markets, it is possible that the FERC could require PacifiCorp to adopt mitigation measures for a specific market.

Transmission

The FERC regulates PacifiCorp's wholesale transmission service. PacifiCorp is required to provide open access transmission service at cost-based rates. The FERC also regulates unbundled transmission service to retail customers. 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 its wholesale marketing business in accordance with the FERC Standards of Conduct.

Transmission Investment

In July 2008, PacifiCorp filed a petition for declaratory order with the FERC to confirm incentive rate treatment for the Energy Gateway Transmission Expansion Project described in "Transmission and Distribution" above. In October 2008, the FERC granted a 200-basis-point (two-percentage-point) incentive rate adder to PacifiCorp's base return on equity for seven of the eight project segments subject to a future Section 205 rate case filing with the FERC. The FERC did not preclude PacifiCorp from filing for incentive rate treatment for the remaining segment at a future date.

FERC Orders No. 890 and 890-A and 890-B

In February 2007, the FERC adopted a final rule in Order No. 890 designed to strengthen the pro forma OATT by providing greater specificity and increasing transparency. The most significant revisions to the pro forma OATT relate to the development of more consistent methodologies for calculating available transfer capability, changes to the transmission planning process, changes to the pricing of certain generator and energy imbalances to encourage efficient scheduling behavior and changes regarding long-term point-to-point transmission service, including the addition of conditional firm long-term point-to-point transmission service and generation re-dispatch. As a transmission provider with an OATT on file with the FERC, PacifiCorp is required to comply with the requirements of the new rule. PacifiCorp made its first compliance filing amending its OATT in July 2007. Subsequent to this filing, PacifiCorp was required to make additional compliance filings to revise its initial filing, all of which were accepted by the FERC through various orders issued in 2007 and 2008.

In December 2007, the FERC issued Order No. 890-A generally affirming the provisions of the final rule as adopted in Order No. 890 with certain limited clarifications and requiring an additional compliance filing by transmission providers. In March 2008, PacifiCorp submitted its Order No. 890-A compliance filing, which was accepted by the FERC in November 2008. In June 2008, the FERC issued Order No. 890-B, which generally affirmed the provisions of the final rule as adopted in Order No. 890 and Order No. 890-A with certain additional limited clarifications, and which required an additional compliance filing. PacifiCorp filed its Order No. 890-B compliance filing in September 2008, which consisted of non-substantive grammatical revisions to its OATT and which was accepted by the FERC in December 2008. In addition to these filings, PacifiCorp filed other Order No. 890 related compliance filings, including a December 2007 filing proposing changes to its local, regional and sub-regional transmission planning process contained in its OATT. This filing, which is still pending before the FERC, is not anticipated to have a significant impact on PacifiCorp's financial results, but it could have a significant impact on its transmission planning functions.

FERC Reliability Standards

The FERC has approved 88 reliability standards developed by North American Electric Reliability Corporation (the "NERC") and 8 regional variations developed by the WECC. Responsibility for compliance and enforcement of these standards has been given to the WECC. The 88 standards comprise over 600 requirements and sub-requirements with which PacifiCorp must comply. PacifiCorp expects that these standards will change as a result of modifications, guidance and clarification following industry implementation and ongoing audits and enforcement. In January 2008, the FERC approved eight additional cyber security and critical infrastructure protection standards proposed by the NERC. The additional standards became mandatory and enforceable in April 2008. PacifiCorp cannot predict the effect that these standards will have on its consolidated financial results; however, they will likely require increased expenditures for cyber security and other systems for PacifiCorp's critical assets and may have a significant impact on transmission operations and resource planning functions. During 2007, the WECC audited PacifiCorp's compliance with several of the approved reliability standards. In April 2008, PacifiCorp received a notice of a preliminary non-public investigation from the FERC and the NERC to determine whether an outage that occurred in PacifiCorp's transmission system in February 2008 involved any violations of reliability standards. In November 2008, PacifiCorp received preliminary findings from the FERC staff regarding its non-public investigation into the February 2008 outage. In November 2008, in conjunction with the reliability standard review, the FERC took over processing certain aspects of the WECC's 2007 audit. PacifiCorp is analyzing the preliminary results of the audit and the preliminary results of the non-public investigation, and at this time, cannot predict the impact of the audit or the non-public investigation, if any, on its consolidated financial results.

Hydroelectric Relicensing

PacifiCorp's Klamath hydroelectric system is the remaining hydroelectric generating facility actively engaged in the relicensing process with the FERC. PacifiCorp also has requested the FERC to allow decommissioning of certain hydroelectric systems. Most of PacifiCorp's hydroelectric generating facilities are licensed by the FERC as major systems under the Federal Power Act, and certain of these systems are licensed under the Oregon Hydroelectric Act. Refer to Note 13 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for an update regarding hydroelectric relicensing for PacifiCorp's Klamath, Lewis River and Prospect hydroelectric systems.

Hydroelectric Decommissioning

Powerdale Hydroelectric Facility – Hood River, Oregon

In June 2003, PacifiCorp entered into a settlement agreement to remove the 6-MW Powerdale plant rather than pursue a new license, based on an analysis of the costs and benefits of relicensing versus decommissioning. Removal of the Powerdale dam and associated system features, which is subject to the FERC and other regulatory approvals, is projected to cost $6 million, excluding inflation. Plant shut down and removal was scheduled to commence in 2010. However, in November 2006, flooding damaged the Powerdale plant and rendered its generating capabilities inoperable. In February 2007, the FERC granted PacifiCorp's request to cease generation at the plant; however, removal is still scheduled for 2010. Also in February 2007, PacifiCorp submitted a request to the FERC to allow PacifiCorp to defer the remaining net book value and any additional removal costs of this system as a regulatory asset. In May 2007, the FERC issued an order that approved PacifiCorp's proposed accounting entries, thereby allowing PacifiCorp to reclassify the net book value and the estimated removal costs to a regulatory asset. PacifiCorp has received approval from its state regulatory commissions to defer and recover these costs.

Condit Hydroelectric Facility – White Salmon River, Washington

In September 1999, a settlement agreement to remove the 14-MW Condit hydroelectric facility was signed by PacifiCorp, state and federal agencies and non-governmental organizations. Under the original settlement agreement, removal was expected to begin in October 2006, with a total cost to decommission not to exceed $17 million, excluding inflation. In early February 2005, the parties agreed to modify the settlement agreement so that removal would not begin until October 2008, with a total cost to decommission not to exceed $21 million, excluding inflation. The settlement agreement is contingent upon receiving a FERC surrender order and other regulatory approvals that are not materially inconsistent with the amended settlement agreement. PacifiCorp is in the process of acquiring all necessary permits within the terms and conditions of the amended settlement agreement. Given the ongoing permitting process and the time needed for system removal and to evaluate impacts on natural resources, decommissioning is now expected to begin in October 2010. In March 2008, the United States Army Corps of Engineers requested PacifiCorp complete an additional study of expected decommissioning impacts on aquatic resources. The study work is complete and results have been provided to the United States Army Corps of Engineers and the Washington Department of Ecology. Absent further information requests, the Washington Department of Ecology is expected to complete the Clean Water Act 401 certification process within the first quarter of 2009. Remaining permitting includes a 404 permit from the United States Army Corps of Engineers and a surrender order from the FERC.

The Bonneville Power Administration Residential Exchange Program

The Northwest Power Act, through the Residential Exchange Program, provides access to the benefits of low-cost federal hydroelectricity to the residential and small-farm customers of the region's investor-owned utilities. The program is administered by the Bonneville Power Administration (the "BPA") in accordance with federal law. Pursuant to agreements between the BPA and PacifiCorp, benefits from the BPA are passed through to PacifiCorp's Oregon, Washington and Idaho residential and small-farm customers in the form of electricity bill credits.

Several publicly owned utilities, cooperatives and the BPA's direct-service industry customers filed lawsuits against the BPA with the United States Court of Appeals for the Ninth Circuit (the "Ninth Circuit") seeking review of certain aspects of the BPA's Residential Exchange Program, as well as challenging the level of benefits previously paid to investor-owned utility customers. In May 2007, the Ninth Circuit issued two decisions that resulted in the BPA suspending payments to the Pacific Northwest's six investor-owned utilities, including PacifiCorp. This resulted in increases to PacifiCorp's residential and small-farm customers' electric bills in Oregon, Washington and Idaho.

In February 2008, the BPA initiated a rate proceeding under the Northwest Power Act to reconsider the level of benefits for the years 2002 through 2006 consistent with the Ninth Circuit's decisions, as well as to re-establish the level of benefits for years 2007 and 2008 and to set the level of benefits for years 2009 and beyond. The BPA issued its final records of decision in September 2008 establishing rates for the time period of October 2008 through September 2009 and adopting a residential purchase and sale agreement for October 2008 through September 2011. In September 2008, the OPUC approved PacifiCorp's request to execute the residential purchase and sale agreement for the payment of Residential Exchange Program benefits from the BPA. In October 2008, the OPUC and WUTC approved PacifiCorp's filing of revised tariff sheets to resume residential exchange credits, effective November 1, 2008. Because these credits are passed through to PacifiCorp's customers, they do not significantly affect PacifiCorp's consolidated financial results.

In October 2008, the BPA offered PacifiCorp a long-term residential purchase and sale agreement for October 2011 through September 2028. In December 2008, the OPUC denied PacifiCorp's request to execute the residential purchase and sale agreement for these years. Also in December 2008, PacifiCorp filed two petitions with the Ninth Circuit for review of the BPA's final records of decision. Because these credits are passed through to PacifiCorp's customers, they do not significantly affect PacifiCorp's consolidated financial results.

Northwest Refund Case

For a discussion of the Northwest Refund case, refer to Note 13 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

United States Mine Safety

PacifiCorp's mining operations are regulated by the federal Mine Safety and Health Administration ("MSHA"), which administers federal mine safety and health laws, regulations and state regulatory agencies. The Mine Improvement and New Emergency Response Act of 2006 ("MINER Act"), enacted in June 2006, amended previous mine safety and health laws to improve mine safety and health and accident preparedness. PacifiCorp is required to develop a written emergency response plan specific to each underground mine it operates. These plans must be reviewed by MSHA every six months. It also requires every mine to have at least two rescue teams located within one hour, and it limits the legal liability of rescue team members and the companies that employ them. The MINER Act also increases civil and criminal penalties for violations of federal mine safety standards and gives MSHA the ability to institute a civil action for relief, including a temporary or permanent injunction, restraining order or other appropriate order against a mine operator who fails to pay the penalties or fines.

Environmental Regulation

PacifiCorp is subject to federal, state and local laws and regulations with regard to air and water quality, RPS, climate change, hazardous and solid waste disposal and other environmental matters and is subject to zoning and other regulation by local authorities. These laws and regulations are subject to a range of interpretation which may ultimately be resolved by the courts. In addition to imposing continuing compliance obligations, these laws and regulations authorize the imposition of substantial penalties for noncompliance including fines, injunctive relief and other sanctions. PacifiCorp believes it is in material compliance with all laws and regulations. The most significant environmental laws and regulations affecting PacifiCorp include:

- The federal Clean Air Act, as well as state laws and regulations impacting air emissions, including State Implementation Plans ("SIP") related to existing and new national ambient air quality standards. Rules issued by the EPA and certain states require substantial reductions in sulfur dioxide ("SO_2") and nitrogen oxide ("NO_x") emissions beginning in 2009 and extending through 2018. PacifiCorp has already installed certain emission control technology and is taking other measures to comply with required reductions. Refer to "Clean Air Standards" section below for additional discussion regarding this topic.
- The federal Water Pollution Control Act ("Clean Water Act") and individual state clean water laws regulate cooling water intake structures and discharges of wastewater, including storm water runoff. PacifiCorp believes that it currently has, or has initiated the process to receive, all required water quality permits. Refer to "Water Quality Standards" section below for additional discussion regarding this topic.
- The federal Comprehensive Environmental Response, Compensation and Liability Act and similar state laws, which may require any current or former owners or operators of a disposal site, as well as transporters or generators of hazardous substances sent to such disposal site, to share in environmental remediation costs. Refer to Note 13 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding environmental contingencies.
- 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. Refer to Note 10 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding PacifiCorp's reclamation obligations.
- The FERC oversees the relicensing of existing hydroelectric systems and is also responsible for the oversight and issuance of licenses for new construction of hydroelectric systems, dam safety inspections and environmental monitoring. Refer to Note 13 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding the relicensing of certain of PacifiCorp's existing hydroelectric generating facilities.

Refer to "Liquidity and Capital Resources" in Item 7 of this Form 10-K for additional information regarding planned capital expenditures related to environmental regulation.

Clean Air Standards

The Clean Air Act provides a framework for protecting and improving the nation's air quality, and controlling mobile and stationary sources of air emissions. The major Clean Air Act programs, which most directly affect PacifiCorp's electric generating facilities, are briefly described below. Many of these programs are implemented and administered by the states, which can impose additional, more stringent requirements.

National Ambient Air Quality Standards

The EPA implements national ambient air quality standards for ozone and fine particulate matter, as well as for other criteria pollutants that set the minimum level of air quality for the United States. Areas that achieve the standards, as determined by ambient air quality monitoring, are characterized as being in attainment, while those that fail to meet the standards are designated as being nonattainment areas. Generally, sources of emissions in a nonattainment area are required to make emissions reductions. A new, more stringent standard for fine particulate matter became effective in December 2006. This standard was appealed to the United States Court of Appeals for the District of Columbia Circuit ("D.C. Circuit"). On February 24, 2009, the D.C. Circuit ruled that the EPA had failed to adequately explain why the annual fine particulate matter standard set at 15 micrograms per cubic meter was sufficiently protective of public health and remanded the rule for further review of the standard. The existing rule will remain in place until the EPA takes further action. Air quality modeling and preliminary air quality monitoring data indicate the counties in Washington, Oregon, Montana, Wyoming, Colorado, Utah and Arizona where PacifiCorp's major emission sources are located are in attainment of the current ambient air quality standards.

In March 2008, the EPA issued final rules to strengthen the national ambient air quality standard for ground level ozone, lowering the standard to 0.075 parts per million from 0.08 parts per million. States have until March 2009 to characterize their attainment status, and the EPA's determinations regarding non-attainment will be made by March 2010 with SIPs due in 2013. Until the EPA makes its final attainment designations, the impact of any new standards on PacifiCorp will not be known.

Regulated Air Pollutants

In 2005, the EPA promulgated the Clean Air Mercury Rule ("CAMR") which would have regulated mercury emissions from coal-fired generating facilities through the use of a cap-and-trade system beginning in 2010, with reductions of approximately 70% when fully implemented in 2018. The CAMR was overturned by the United States Court of Appeals for the District of Columbia Circuit in February 2008. The EPA petitioned the United States Supreme Court for review of the lower court's decision in October 2008. On February 6, 2009, the EPA withdrew its petition for review before the United States Supreme Court and on February 23, 2009, the Supreme Court dismissed the petition. The EPA has indicated it plans to propose a new mercury rule that will require coal-fired generating facilities to utilize Maximum Achievable Control Technology, rather than a cap-and-trade mechanism, to reduce mercury emissions. As a result, PacifiCorp's coal-fired generating facilities may be required to install controls to reduce mercury emissions at each of its facilities rather than making cost-effective mercury emission reductions through a combination of controls and allowances. Depending on the scope and timing of these reduction requirements, as well as the availability and effectiveness of controls, the new rules could impose additional costs on PacifiCorp for control of mercury emissions above the costs anticipated under the CAMR.

The emissions reductions could be made more stringent by current or future regulatory and legislative proposals at the federal or state levels that would result in significant reductions of SO_2, NO_X and mercury, as well as carbon dioxide and other gases that may affect global climate change.

Regional Haze

The EPA has initiated a regional haze program intended to improve visibility at specific federally protected areas. Some of PacifiCorp's generating facilities meet the threshold applicability criteria under the Clean Air Visibility Rules. In accordance with the federal requirements, states were required to submit SIPs by December 2007 to demonstrate reasonable progress toward achieving natural visibility conditions in certain Class I areas by requiring emission controls, known as best available retrofit technology, on sources with emissions that are anticipated to cause or contribute to impairment of visibility. Wyoming has not yet submitted its SIP and is continuing to review the planned emission reductions at PacifiCorp's Wyoming generating facilities. Utah submitted its SIP and suggested that the emission reduction projects planned by PacifiCorp are sufficient to meet its initial emission reduction requirements. In January 2009, the EPA made a finding that 37 states, including Wyoming, had failed to file a SIP that met some or all of the basic program requirements under the regional haze program. As a result, Wyoming has two years from January 2009 to file and obtain EPA approval of a SIP that meets all of the regional haze program requirements or the state will be subject to a federal implementation plan, with the EPA administering the regional haze program. PacifiCorp believes that its planned emission reduction projects will satisfy the regional haze requirements in Utah and Wyoming; however, it is possible that some additional controls may be required once the respective SIPs have been submitted or that the timing of the installation of planned controls could be changed.

New Source Review

Under existing New Source Review ("NSR") 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 major stationary source of an NSR-regulated pollutant, or (ii) making a physical or operational change to an existing stationary source of such pollutants that increases certain levels of emissions, unless the changes are exempt under the regulations (including routine maintenance, repair and replacement of equipment). In general, projects subject to NSR regulations are subject to pre-construction review and permitting under the Prevention of Significant Deterioration ("PSD") provisions of the Clean Air Act. Under the PSD program, a project that emits threshold levels of regulated pollutants must undergo a "best available control technology" analysis and evaluate the most effective emissions controls. These controls must be installed in order to receive a permit. Violations of NSR regulations, which may be alleged by the EPA, states and environmental groups, among others, potentially subject a utility to material fines and other sanctions and remedies, including requiring installation of enhanced pollution controls and funding supplemental environmental projects.

As part of an industry-wide investigation to assess compliance with the NSR and PSD provisions, the EPA has requested from numerous utilities information and supporting documentation regarding their capital projects for various generating facilities. Between 2001 and 2003, PacifiCorp responded to requests for information relating to its capital projects at its generating facilities and has been engaged in periodic discussions with the EPA over several years regarding PacifiCorp's historical projects and their compliance with NSR and PSD provisions. An NSR enforcement case against another utility has been decided by the United States Supreme Court, holding that an increase in annual emissions of a generating facility, when combined with a modification (i.e., a physical or operational change), may trigger NSR permitting. PacifiCorp cannot predict the outcome of its discussions with the EPA at this time; however, PacifiCorp could be required to install additional emissions controls, and incur additional costs and penalties, in the event it is determined that PacifiCorp's historical projects did not meet all regulatory requirements.

Numerous changes have been proposed to the NSR rules and regulations over the last several years. These changes, withdrawals of proposed changes, differing interpretations by the EPA and the courts, and the recent change in administration, create risk and uncertainty for regulated entities in complying with NSR requirements when permitting new projects and installing emission controls at existing facilities. PacifiCorp monitors these changes and interpretations to ensure permitting activities are conducted in accordance with the applicable requirements.

Renewable Portfolio Standards

The RPS described below could significantly impact PacifiCorp's financial results. Resources that meet the qualifying electricity requirements under the RPS vary from state-to-state. Each state's RPS requires some form of compliance reporting and PacifiCorp can be subject to penalties in the event of non-compliance.

In November 2006, Washington voters approved a ballot initiative establishing a RPS requirement for qualifying electric utilities, including PacifiCorp. The requirements are that 3% of retail sales by January 2012 through 2015, 9% of retail sales by January 2016 through 2019 and 15% of retail sales by January 2020 be supplied by qualified renewable resources. The WUTC has adopted final rules to implement the initiative. PacifiCorp expects to be able to recover its costs of complying with the RPS, either through rate cases or an adjustment mechanism.

In June 2007, the Oregon Renewable Energy Act (the "OREA") was adopted, providing a comprehensive renewable energy policy for Oregon. Subject to certain exemptions and cost limitations established in the OREA, PacifiCorp and other qualifying electric utilities must meet minimum qualifying electricity requirements for electricity sold to retail customers of at least 5% in 2011 through 2014, 15% in 2015 through 2019, 20% in 2020 through 2024 and 25% in 2025 and subsequent years. As required by the OREA, the OPUC has approved an automatic adjustment clause to allow an electric utility, including PacifiCorp, to recover prudently incurred costs of its investments in renewable energy generating facilities and associated transmission costs. The OPUC and the Oregon Department of Energy have undertaken additional rulemaking proceedings to further implement the initiative. PacifiCorp expects to be able to recover its costs of complying with the RPS through the automatic adjustment mechanism.

California law requires electric utilities to increase their procurement of renewable resources by at least 1% of their annual retail electricity sales per year so that 20% of their annual electricity sales are procured from renewable resources by no later than December 31, 2010. In May 2008, PacifiCorp and other small multi-jurisdictional utilities ("SMJU") received further guidance from the CPUC on the treatment of SMJUs in the California RPS program. In August 2008, concurrent with its annual RPS compliance filing, PacifiCorp, joined by another SMJU, filed a Joint Motion for Review of the decision, including banking of RPS procurement made while it awaited further guidance from the CPUC on the treatment of SMJUs during the 2004-2006 period. PacifiCorp noted among other things on this filing that its interpretation is consistent with the CPUC guidance and best serves the interests of its customers by recognizing past, good faith efforts to comply with California's RPS program beginning January 2004. PacifiCorp is currently awaiting the CPUC's response to the Joint Motion for Review. Absent further direction from the CPUC on treatment of SMJUs, PacifiCorp cannot predict the impact of the California RPS on its financial results.

In March 2008, Utah's governor signed Utah Senate Bill 202, *Energy Resource and Carbon Emission Reduction Initiative*. Among other things, this law provides that, beginning in the year 2025, 20% of adjusted retail electric sales of all Utah utilities be supplied by renewable energy, if it is cost effective. Retail electric sales will be adjusted by deducting the amount of generation from sources that produce zero or reduced carbon emissions, and for sales avoided as a result of energy efficiency and demand-side management programs. Qualifying renewable energy sources can be located anywhere in the WECC areas and renewable energy credits can be used. PacifiCorp expects to be able to recover its costs of complying with the law, either through rate cases or adjustment mechanisms.

Climate Change

As a result of increased attention to global climate change in the United States, there are significant future environmental regulations under consideration to increase the deployment of clean energy technologies and regulate emissions of greenhouse gas at the state, regional and federal levels. Congress and federal policy makers are considering climate change legislation and a variety of national climate change policies. President Obama has expressed support for an economy-wide greenhouse gas cap-and-trade program that would reduce emissions 80% below 1990 levels by 2050. Alternatively, or in conjunction with a cap, policy makers have discussed the possibility of imposing a tax on greenhouse gas emissions. Given the strong interest and support in reducing greenhouse gas emissions, PacifiCorp's electric generating facilities are likely to be subject to regulation of greenhouse gas emissions within the next several years.

In addition, nongovernmental organizations have become more active in initiating citizen suits under existing environmental and other laws and the EPA issued an advanced notice of proposed rulemaking in 2008 to consider issues associated with regulating greenhouse gas emissions under the Clean Air Act. The United States Supreme Court has ruled that the EPA has the authority under the Clean Air Act to regulate emissions of greenhouse gases from motor vehicles and that the EPA must make a determination relating to the danger posed by greenhouse gas emissions. Furthermore, pending cases that address the potential public nuisance from greenhouse gas emissions from electricity generators and the EPA's failure to regulate greenhouse gas emissions from new and existing coal-fired generating facilities are expected to become active. While debate continues at the national level over the direction of domestic climate policy, several states have developed state-specific laws or regional legislative initiatives to reduce greenhouse gas emissions that are expected to impact PacifiCorp, including:

- The Western Regional Climate Action Initiative ("Western Climate Initiative"), a comprehensive regional effort to reduce greenhouse gas emissions by 15% below 2005 levels by 2020 through a cap-and-trade program that includes the electricity sector. The Western Climate Initiative includes the states of Arizona, California, Montana, New Mexico, Oregon, Utah and Washington and the provinces of British Columbia, Manitoba, Ontario and Quebec. The state and provincial partners have agreed to begin reporting greenhouse gas emissions in 2011 for emissions that occur in 2010. The first phase of the cap-and-trade program will begin in January 2012.
- 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% below 1990 levels by 2050. In addition, California has adopted legislation that imposes 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-fired generating facility, as well as legislation that adopts an economy-wide cap on greenhouse gas emissions to 1990 levels by 2020.
- The Washington and Oregon governors enacted legislation in May 2007 and August 2007, respectively, establishing economy-wide goals for the reduction of greenhouse gas emissions in their respective states. Washington's goals seek to (i) by 2020, reduce emissions to 1990 levels; (ii) by 2035, reduce emissions to 25% below 1990 levels; and (iii) by 2050, reduce emissions to 50% below 1990 levels, or 70% below Washington's forecasted emissions in 2050. Oregon's goals seek to (i) by 2010, cease the growth of Oregon greenhouse gas emissions; (ii) by 2020, reduce greenhouse gas levels to 10% below 1990 levels; and (iii) by 2050, reduce greenhouse gas levels to at least 75% below 1990 levels. Each state's legislation also calls for state government-developed policy recommendations in the future to assist in the monitoring and achievement of these goals. The impact of the enacted legislation on PacifiCorp cannot be determined at this time.

In addition to pending legislative proposals to regulate greenhouse gas emissions, in July 2008, the EPA issued an advance notice of proposed rulemaking presenting information relevant to, and soliciting public comment on, how to respond to the United States Supreme Court's decision in *Massachusetts v. EPA*, in which the United States Supreme Court ruled that the Clean Air Act authorizes regulation of greenhouses gases because they meet the definition of an air pollutant under the Clean Air Act, given the potential ramifications of a decision to regulate such emissions under the existing Clean Air Act framework.

PacifiCorp is currently subject to specific greenhouse gas-related requirements, including mandatory greenhouse gas reporting requirements in California, Washington and Oregon. California, Washington and Oregon also require the consideration of greenhouse gas emissions in new resource decisions through the establishment of greenhouse gas emissions performance standards and the requirement for mitigation of greenhouse gas emissions in conjunction with the addition of new emitting resources.

PacifiCorp believes in implementing public policy to address climate change in a manner that informs all constituents of cost ramifications and attempts to minimize such costs. PacifiCorp believes that research and development must be undertaken on a large scale and in a coordinated manner to obtain technologies that reduce carbon emissions while still providing reasonably priced energy and that the development and deployment of low-carbon electricity technologies must precede the imposition of significant emission reduction requirements or taxes or fees on emissions. PacifiCorp continues to add renewable and low-carbon electric capacity to its generation portfolio in an effort to reduce the carbon intensity of its generating capacity. From 2005 to 2008, through the addition of lower-carbon and renewable generation resources, PacifiCorp reduced the CO_2 intensity of its electricity generation portfolio by 11% while increasing the number of MWh generated by 17%. In addition, PacifiCorp has engaged in several voluntary programs designed to reduce or avoid greenhouse gas emissions, including the EPA's sulfur hexafluoride reduction program, refrigerator recycling programs and the EPA landfill methane outreach program. PacifiCorp is a member of the California Climate Action Registry and The Climate Registry, under which it reports and certifies its greenhouse gas emissions.

Climate change may cause physical and financial risk through, among other things, sea level rise, changes in precipitation and extreme weather events. Energy needs may increase or decrease, based on overall changes in weather. Availability of resources to generate electricity, such as water for hydroelectric production and cooling purposes, may also be impacted by climate change and could influence PacifiCorp's existing and future electricity generation portfolio. These issues may have a direct impact on the costs of electricity production and increase the price paid by customers for electricity.

Legislative and regulatory responses to climate change have the potential to create financial risk. Adoption of early and stringent limits on greenhouse gas emissions could significantly adversely impact PacifiCorp's current and future fossil-fueled facilities, and therefore, its financial results. To the extent that PacifiCorp is not allowed by its regulators or cannot otherwise recover the costs incurred to comply with climate change requirements, these requirements could have a material adverse impact on PacifiCorp's financial results. Costs of compliance with environmental and other regulatory requirements are historically recovered in rates but risk regulatory lag. Although PacifiCorp does not make policy and does not take a position on the scientific aspects of climate change, it supports an informed dialogue on climate change and intends to implement actions to comply with any new legislation or regulation. The impact of any pending judicial proceedings and any pending or enacted federal and state climate change legislation and regulation cannot be determined at this time; however, adoption of stringent limits on greenhouse gas emissions could adversely impact PacifiCorp's current and future fossil-fueled generating facilities, and, therefore, its financial results.

Water Quality Standards

The Clean Water Act establishes the framework for maintaining and improving water quality in the United States through a program that regulates, among other things, discharges to and withdrawals from waterways. The Clean Water Act requires that cooling water intake structures reflect the "best technology available for minimizing adverse environmental impact" to aquatic organisms. In July 2004, the EPA established significant new national technology-based performance standards for existing electric generating facilities that take in more than 50 million gallons of water per day. These rules are aimed at minimizing the adverse environmental impacts of cooling water intake structures by reducing the number of aquatic organisms lost as a result of water withdrawals. In response to a legal challenge to the rule, in January 2007, the Second Circuit Court of Appeals remanded almost all aspects of the rule to the EPA, leaving companies with cooling water intake structures uncertain regarding compliance with these requirements. Petitions for certiorari are pending before the United States Supreme Court regarding the Second Circuit Court of Appeals' decision. The United States Supreme Court will consider whether Section 316(b) of the Clean Water Act authorizes the EPA to compare costs with benefits in determining "best technology available for minimizing adverse environmental impact" of cooling water intake solutions. Compliance and the potential costs of compliance, therefore, cannot be ascertained until such time as the United States Supreme Court's decision is rendered or further action is taken by the EPA. Currently, PacifiCorp's Dave Johnston plant exceeds the 50 million gallons of water per day intake threshold. In the event that PacifiCorp's existing intake structures require modification or alternative technology required by new rules, expenditures to comply with these requirements could be significant.

Ash Disposal

In December 2008, an ash impoundment dike at the Tennessee Valley Authority's Kingston power plant collapsed after heavy rain, releasing a significant amount of fly ash, bottom ash, coal combustion byproducts and water to the surrounding area. In light of this incident, federal and state officials have called for greater regulation of coal combustion storage and disposal. PacifiCorp operates coal ash impoundments and, in January 2008, voluntarily committed under an industry action plan to disposal restrictions, monitoring and reporting of coal combustion products that exceed requirements under current law. These ash impoundments could be impacted by additional regulation and could pose additional costs associated with ash management and disposal activities at PacifiCorp's coal-fired generating facilities. The impact of any new regulations on coal combustion products cannot be determined at this time.

ITEM 1A. RISK FACTORS

We are subject to certain risks in our business operations as described below. Careful consideration of these risks, together with all of the other information included in this annual report and the other public information filed by us, should be made before making an investment decision. The risks and uncertainties described below are not the only ones we face. Additional risks and uncertainties not presently known or that are currently deemed immaterial may also impair our business operations.

We are subject to extensive regulations and legislation that affect our operations and costs. These regulations and laws are complex, dynamic and subject to change.

We are subject to numerous regulations and laws enforced by regulatory agencies. These regulatory agencies include, among others, the FERC, the WECC, the EPA and the public utility commissions in Utah, Oregon, Wyoming, Washington, Idaho and California.

Regulations affect almost every aspect of our business and limit our ability to independently make and implement management decisions regarding, among other items, constructing, acquiring or disposing of operating assets; business combinations; setting rates charged to customers; establishing capital structures and issuing debt or equity securities; engaging in transactions between our subsidiaries and affiliates; and paying dividends. Regulations are subject to ongoing policy initiatives and we cannot predict the future course of changes in laws, regulations and orders, or the ultimate effect that regulatory changes may have on us. However, such changes could materially impact our financial results. For example, such changes could result in, but are not limited to, increased retail competition within our service territories; new environmental requirements, including the implementation of RPS and greenhouse gas emissions reduction goals; implementation of energy efficiency mandates or renewable energy standards; increased retail competition within our service territories; the acquisition by a municipality or other quasi-governmental body of our 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 our current cost recovery arrangements, including income tax recovery.

Federal and state energy regulation changes are one of the more challenging aspects of managing utility operations. New and expanded regulations imposed by policy makers, court systems, and industry restructuring have imposed changes on the industry. The following are examples of changes to our regulatory environment that have impacted us:

- Energy Policy Act – The Energy Policy Act impacts many segments of the energy industry. The United States Congress granted the FERC additional authority in the Energy Policy Act, which expanded its role from a regulatory body to an enforcement agency. To implement the law, the FERC adopted new regulations and issued regulatory decisions addressing electric system reliability, electric transmission planning, operation, expansion and pricing, regulation of utility holding companies, and enforcement authority, including the ability to assess civil penalties of up to $1 million per day per violation for non-compliance. The FERC has essentially completed its implementation of the Energy Policy Act and the emphasis of its recent decisions is on reporting and compliance. In that regard, the FERC has vigorously exercised its enforcement authority by imposing significant civil penalties for violations of its rules and regulations. For example, as a result of past events affecting electric reliability, the Energy Policy Act 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. Since the adoption of the Energy Policy Act, the FERC has approved numerous electric reliability, cyber security and critical infrastructure protection standards developed by the NERC. A transmission owner's reliability compliance issues with these and future standards could result in financial penalties. In FERC Order No. 693, the FERC implemented its authority to impose penalties of up to $1 million per day per violation for failure to comply with electric reliability standards. The adoption of these and future electric reliability standards has imposed more comprehensive and stringent requirements on us, which has increased compliance costs. It is possible that the cost of complying with these and any additional standards adopted in the future could adversely affect our financial results.

- FERC Orders – The FERC has issued a series of orders to foster greater competition in wholesale power markets by reducing barriers to entry in the provision of transmission service. In FERC Order Nos. 888, 889, 890, 890-A, 890-B and 717, the FERC required electric utilities to adopt a proforma OATT by which transmission service would be provided on a just, reasonable and not unduly discriminatory or preferential basis. The rules adopted by these orders promote transparency and consistency in the administration of the OATT, increase the ability of customers to access new generating resources and promote efficient utilization of transmission by requiring an open, transparent and coordinated transmission planning process. Together with the increased reliability standards required of transmission providers, the costs of operating the transmission system and providing transmission service have increased, and to the extent such increased costs are not recovered in rates charged to customers, they could adversely affect our financial results.
- Hydroelectric Relicensing – Currently, the Klamath hydroelectric system, whose operating license has expired and is operating on annual licenses, is engaged in the FERC relicensing process. Through negotiations with relicensing stakeholders, disposition of the relicensing process and a path toward dam transfer and removal by a third party may occur as an alternative to relicensing. Hydroelectric relicensing is a political and public regulatory process involving sensitive resource issues and uncertainties. We cannot predict with certainty the requirements (financial, operational or otherwise) that may be imposed by relicensing, the economic impact of those requirements, and whether a new license will ultimately be issued or whether we will be willing to meet the relicensing requirements to continue operating our hydroelectric generating facilities. Loss of hydroelectric resources or additional commitments arising from relicensing could adversely affect our financial results.

In addition to the foregoing examples, the new Obama administration has stated that many aspects of energy and the environment, including renewable resources and climate change, will be a key component of its policy agenda. We cannot predict what actions the administration may take, the laws or regulations that may be adopted or the ultimate effect that any of these may have on us; however, such effect could materially impact our financial results.

We are subject to numerous environmental, health, safety and other laws, regulations and other requirements that could adversely affect our financial results.

Operational Standards

We are subject to numerous environmental, health, safety and other laws, regulations and other requirements affecting many aspects of our present and future operations, including, among others:

- the provisions of the MINER Act to improve underground coal mine safety and emergency preparedness;
- the implementation of federal and state RPS; and
- other laws or regulations that establish or could establish standards for greenhouse gas emissions, air quality, water quality, wastewater discharges, solid waste and hazardous waste.

These and related laws, regulations and orders generally require us to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals.

Compliance with environmental, health, safety, and other laws, regulations and other requirements can require significant capital and operating expenditures, including expenditures for new equipment, inspection, cleanup costs, damages arising out of contaminated properties, and fines, penalties and injunctive measures affecting operating assets for failure to comply with environmental regulations. Compliance activities pursuant to regulations could be prohibitively expensive. As a result, some facilities may be required to shut down or alter their operations. Further, we may not be able to obtain or maintain all required environmental regulatory approvals for our operating assets or development projects. Delays in or active opposition by third parties to obtaining any required environmental or regulatory permits, failure to comply with the terms and conditions of the permits or increased regulatory or environmental requirements may increase costs or prevent or delay us from operating our facilities, developing new facilities, expanding existing facilities or favorably locating new facilities. If we fail to comply with all applicable environmental requirements, we may be subject to penalties and fines or other sanctions. The costs of complying with current or new environmental, health, safety and other laws, regulations and other requirements could adversely affect our financial results. Not being able to operate existing facilities or develop new electric generating facilities to meet customer energy needs could require us to increase our purchases of power from the wholesale markets, which could increase market and price risks and adversely affect our financial results. Proposals for voluntary initiatives and mandatory controls are being discussed both in the United States and worldwide to reduce so-called “greenhouse gases” such as carbon dioxide (a by-product of burning fossil fuels), methane (the primary component of natural gas) and methane leaks from pipelines. These actions could result in increased costs to (i) operate and maintain our facilities, (ii) install new emission controls on our facilities and (iii) administer and manage any greenhouse gas emissions program. These actions could also increase the demand for natural gas, causing increased natural gas prices, thereby adversely affecting our operations.

Further, our current regulatory rate structure or long-term customer contracts may not necessarily allow us to recover all costs incurred to comply with new environmental requirements. The inability to fully recover such costs in a timely manner could adversely affect our financial results.

Site Cleanup and Contamination

Environmental, health, safety, and other laws, regulations and other requirements also impose obligations to remediate contaminated properties or to pay for the cost of such remediation, often by parties that did not actually cause the contamination. We are generally responsible for on-site liabilities, and in some cases off-site liabilities, associated with the environmental condition of our assets, including power generating facilities and electric transmission and distribution assets that we have acquired or developed, regardless of when the liabilities arose and whether they are known or unknown. In connection with acquisitions, we may obtain or require indemnification against some environmental liabilities. If we incur a material liability, or the other party to a transaction fails to meet its indemnification obligations, we could suffer material losses. We have established reserves to recognize our estimated obligations for known remediation liabilities, but such estimates may change materially over time. PacifiCorp is required to fund its portion of the costs of mine reclamation at its coal-mining operations, which include principally site restoration. In addition, 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 that may be material.

Recovery of our costs is subject to regulatory review and approval, and the inability to recover costs may adversely affect our financial results.

State Rate Proceedings

Rates are established for our regulated retail service through state regulatory proceedings. These proceedings typically involve multiple parties, including government bodies and officials, consumer advocacy groups and various consumers of energy, who have differing concerns, but who generally have the common objective of limiting rate increases. Decisions are subject to appeal, potentially leading to additional uncertainty associated with the approval proceedings.

Each state sets retail rates based in part upon the state utility commission's acceptance of an allocated share of total utility costs. When states adopt different methods to calculate interjurisdictional cost allocations, some costs may not be incorporated into rates of any state. Ratemaking is also generally done on the basis of estimates of normalized costs, so if a given year's realized costs are higher than normalized costs, rates will not be sufficient to cover those costs. Each state utility commission generally sets rates based on a test year established in accordance with that commission's policies. Certain states use a future test year or allow for escalation of historical costs, while other states use a historical test year. Use of a historical test year may cause regulatory lag, which results in us incurring costs, including significant new investments, for which recovery through rates is delayed. State regulatory commissions also decide the allowed rates of return MEHC will be given an opportunity to earn on its equity investment in us. In addition, they also decide the allowed levels of expense and investment that they deem are just and reasonable in providing service. The state regulatory commissions may disallow recovery in rates for any costs that do not meet such standard.

In Utah and Washington, we are not permitted to pass through energy cost increases in our electric rates without a general rate case. Any significant increase in fuel costs for electricity generation or purchased power costs could have a negative impact on us, despite our efforts to minimize this impact through future general rate cases or the use of hedging instruments. Any of these consequences could adversely affect our financial results.

While rate regulation is premised on providing a fair opportunity to obtain a reasonable rate of return on invested capital, the state regulatory commissions do not guarantee that we will be able to realize a reasonable rate of return.

FERC Jurisdiction

The FERC establishes cost-based tariffs under which we provide transmission services to wholesale markets and retail markets in states that allow retail competition. The FERC also has responsibility for approving both cost- and market-based rates under which we sell electricity at wholesale and has licensing authority over most of our hydroelectric generating facilities. The FERC may impose price limitations, bidding rules and other mechanisms to address some of the volatility of these markets or may (pursuant to pending or future proceedings) revoke or restrict our ability to sell electricity at market-based rates, which could adversely affect our financial results. The FERC may also impose substantial civil penalties for any non-compliance with the Federal Power Act and the FERC's rules and orders.

We are actively pursuing, developing and constructing new or expanded facilities, the completion and expected cost of which is subject to significant risk, and we have significant funding needs related to our planned capital expenditures.

We are engaged in several large construction or expansion projects, including construction and development of wind-powered generating facilities and various capital projects related to generation, transmission and distribution. In addition, in connection with MEHC's acquisition of us in early 2006, we have committed to undertake several other capital expenditure projects, principally relating to environmental controls, transmission and distribution, renewable generation and other facilities. Including these investments, we expect to incur substantial construction, expansion and other capital-related costs over the next several years. Additional significant investments may be incurred as a result of the issuance and implementation of state and federal RPS, greenhouse gas emissions reduction goals and other environmental requirements.

Development and construction of major facilities are subject to substantial risks, including fluctuations in the price and availability of commodities, manufactured goods, equipment, labor and other items over a multi-year construction period, as well as the economic viability of our suppliers. These risks may result in higher than expected costs to complete an asset and place it in service. Such costs may not be recoverable in the regulated rates or market prices we are able to charge our customers. It is also possible that additional generation needs may be obtained through power purchase agreements which could increase long-term purchase obligations and force reliance on the operating performance of a third party. The inability to successfully and timely complete a project, avoid unexpected costs or to recover any such costs could adversely affect our financial results.

Furthermore, we depend upon both internal and external sources of liquidity to provide working capital and to fund capital requirements. These sources include revolving credit facilities with a variety of banks and financial institutions. Many large financial institutions have experienced financial difficulties, with several unable to survive as independent institutions with bankruptcy in some cases. It is possible that these financial institutions may be unable to provide previously arranged funding under revolving credit facilities or other arrangements. Economic and credit market environments, such as those experienced in 2008, may adversely affect our ability to obtain liquidity from external sources. If these funds are not available, we may need to postpone or cancel planned capital expenditures.

Failure to construct our planned projects could limit opportunities for revenue growth, increase operating costs and adversely affect the reliability of electric service to our customers. For example, if we are not able to expand our existing generating facilities, we may be required to enter into long-term electricity procurement contracts or procure electricity at more volatile and potentially higher prices in the spot markets to support growing retail loads.

The current disruptions in the financial markets could affect our ability to obtain debt financing, draw upon or renew existing credit facilities and have other adverse effects on us.

The United States and global credit markets have experienced historic dislocations and liquidity disruptions that have caused financing to be unavailable in many cases. These circumstances have materially impacted liquidity in the bank and capital debt markets, making financing terms less attractive for borrowers who are able to find financing, and in many cases have resulted in the unavailability of certain types of debt financing. In addition, many large financial institutions have experienced financial difficulties, with some unable to survive as independent institutions and others filing for bankruptcy protection. These conditions may continue to impact the number of financial institutions able to provide credit. It is also possible that these financial institutions may not be able to provide previously arranged funding under revolving credit facilities or other arrangements like those that we have established as potential sources of liquidity for working capital and to fund capital requirements. For example, our revolving credit facility arrangements have been reduced due to the Lehman Brothers Holdings Inc. bankruptcy filing in September 2008. Continued uncertainty in the credit markets may negatively impact our ability to access funds on favorable terms or at all. If we need to access funds but are unable to do so, that failure could have a material adverse effect on our financial condition and results of operations.

We are exposed to credit risk of counterparties and failure of our significant customers to perform under or to renew their contracts, or failure to obtain new customers for expanded capacity, could adversely affect our financial results.

We rely on our wholesale customers to fulfill their commitments and pay for energy delivered to them on a timely basis. Adverse economic conditions or other events affecting counterparties with whom we conduct business could impair the ability of these counterparties to pay for services or fulfill their contractual obligations, or cause them to delay or reduce such payments. We depend on these counterparties to remit payments on a timely basis. Some suppliers and customers have been experiencing deteriorating credit quality over the course of 2008, and we continue to monitor these parties to attempt to reduce the impact of any potential counterparty default. Any delay or default in payment or limitation to negotiate alternative arrangements could adversely affect our financial results.

We also have certain long-term arrangements for which if we are unable to renew, remarket, or find replacements, our sales volumes and revenues would be exposed to reduction and increased volatility. For example, without long-term transmission or power purchase agreements, we cannot assure that we will be able to operate profitably. Failure to maintain existing long-term agreements or secure new long-term agreements could adversely affect our financial results.

The replacement of any existing long-term agreements depends on market conditions and other factors that may be beyond our control.

A significant decrease in demand for electricity in the markets served by us would significantly decrease our operating revenues and thereby adversely affect our business and financial results.

A sustained decrease in demand for electricity in the markets served by us would significantly reduce our operating revenue and adversely affect our financial results. Factors that could lead to a decrease in market demand include, among others:

- a recession or other adverse economic condition, including the significant adverse changes in the economy and credit markets in 2008, which may continue into future periods, that results in a lower level of economic activity or reduced spending by consumers on electricity;
- an increase in the market price of electricity or a decrease in the price of other competing forms of energy;
- efforts by customers, legislators and regulators to reduce consumption of energy through various conservation and energy efficiency measures and programs;
- higher fuel taxes or other governmental or regulatory actions that increase, directly or indirectly, the cost of natural gas or the fuel source for electricity generation or that limit the use of natural gas or the generation of electricity from fossil fuels; and
- a shift to more energy-efficient or alternative fuel machinery or an improvement in fuel economy, whether as a result of technological advances by manufacturers, legislation mandating higher fuel economy or lower emissions, price differentials, incentives or otherwise.

We are subject to market risk, counterparty performance risk and other risks associated with wholesale energy markets.

In general, wholesale 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 volumetric changes affecting the availability of or demand for electricity and fuel. We purchase electricity and fuel in the open market or pursuant to short-term or variable-priced contracts as part of our normal operating business. If market prices rise, especially in a time when larger than expected volumes must be purchased at market or short-term prices, we may incur significantly greater expense than anticipated. Likewise, if electricity market prices decline in a period when we are a net seller of electricity in the wholesale market, we will earn less revenue.

Wholesale electricity prices in our service areas 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. Volumetric changes are caused by unanticipated changes in generation availability and/or changes in customer loads due to the weather, electricity prices, the economy, regulations or customer behavior. Although we plan for resources to meet our current and expected retail and wholesale load obligations, we are a net buyer of electricity during some peak periods and therefore our energy costs may be adversely impacted by market risk. In addition, we may not be able to timely recover all, if any, of those increased costs unless the state regulators authorize such recovery.

We are also exposed to risks related to performance of contractual obligations by wholesale suppliers and customers. These risks have increased as a result of the current recessionary environment and many companies' weakened financial condition. We rely on suppliers to deliver commodities, primarily natural gas, coal and electricity, in accordance with short- and long-term contracts. Failure or delay by suppliers to provide these commodities pursuant to existing contracts could disrupt our ability to deliver electricity and require us to incur additional expenses to meet customer needs.

We rely 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 us to find other customers to take the energy at lower prices than the original customers committed to pay. At certain times of the year, prices paid by us for energy needed to satisfy our customers' energy needs may exceed the amounts we receive through rates from these customers. If our wholesale customers are unable to pay us for energy or hedging transactions, it may have a significant adverse impact on our cash flows. If the strategy used to minimize these risk exposures is ineffective or if our wholesale customers' financial condition deteriorates as a result of recent economic conditions, causing them to be unable to pay us, significant losses could result.

The deterioration in the credit quality of certain of our wholesale suppliers and customers as a result of the adverse economic changes experienced in 2008 could have an adverse impact on their ability to perform their contractual obligations, which in turn could have an adverse impact on our financial results.

Inflation and changes in commodity prices and fuel transportation costs may adversely affect our financial results.

Inflation may affect our business by increasing both operating and capital costs. As a result of existing rate agreements and competitive price pressures, we may not be able to pass the costs of inflation on to our customers. If we are unable to manage cost increases or pass them on to our customers, our financial results could be adversely affected.

We have a multitude of long-term agreements of varying duration that are material to the operation of our business, such as power purchase, coal and gas supply and transportation contracts, and the failure to maintain, renew or replace these agreements on similar terms and conditions could increase our exposure to changes in prices, thereby increasing the volatility of our financial results. We currently have contracts of varying durations for the supply and transportation of coal for our existing generation capacity, although we obtain some of our coal supply from mines owned or leased by us. When these contracts expire or if they are not honored, we may not be able to purchase or transport coal on terms as favorable as the current contracts. We have similar exposures regarding the market price of natural gas. Changes in the cost of coal or natural gas supply and transportation and changes in the relationship between such costs and the market price of power will affect our financial results. Since the sales price we receive for power may not change at the same rate as our coal or natural gas supply and transportation costs, we may be unable to pass on the changes in costs to our customers.

Our financial results may be adversely affected if we are unable to obtain adequate, reliable and affordable access to transmission service.

We depend on transmission facilities owned and operated by other utilities to transport electricity to both wholesale and retail markets. If adequate transmission is unavailable, we may be unable to purchase and sell and deliver electricity. Such unavailability could also hinder our ability to provide adequate or economical electricity to our wholesale and retail customers and could adversely impact our financial results.

Our operating results may fluctuate on a seasonal and quarterly basis and may be adversely affected by weather.

The sale of electric power is generally a seasonal business. In the markets in which we operate, customer demand peaks in the winter months due to heating requirements and also peaks in the summer months due to irrigation and cooling needs. Extreme weather conditions such as heat waves or winter storms could cause these seasonal fluctuations to be more pronounced. Periods of low rainfall or snow-pack may also impact electric generation at our hydroelectric generating facilities. Our wind-powered generating facilitates are also climate-contingent resources.

As a result, our overall financial results may fluctuate substantially on a seasonal and quarterly basis. We have historically sold less power, and consequently earned less income, when weather conditions are mild. Unusually mild weather in the future may adversely affect our financial results through lower revenues or margins. Conversely, unusually extreme weather conditions could increase our costs to provide power and could adversely affect our financial results. Furthermore, during or following periods of low rainfall or snow-pack, we may obtain substantially less electricity from hydroelectric generating facilities and must purchase greater amounts of electricity from the wholesale market or from other sources at market prices. We have added substantial wind-powered generating capacity which is a climate dependent resource resulting in a variable production output that may at times affect the amount of energy available for sale or purchase. The extent of fluctuation in financial results may change depending on a number of factors related to our regulatory environment and contractual agreements, including our ability to recover power costs and terms of the power sale contracts.

We are subject to operating uncertainties that could adversely affect our financial results.

The operation of complex electric utility (including generation, transmission and distribution) systems that are spread over large geographic areas involves many operating uncertainties and events beyond our control. These potential events include the breakdown or failure of power generation equipment, transmission and distribution lines or other equipment or processes; unscheduled generating facility outages; strikes, lockouts or other labor-related actions; shortage of qualified labor; transmission and distribution system constraints or outages; fuel shortages or interruptions; unavailability of critical equipment, materials and supplies; low water flows and other weather-related impacts; performance below expected levels of output, capacity or efficiency; 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. Any of these risks or other operational risks could significantly reduce or eliminate our revenues or significantly increase our expenses. For example, if we cannot operate generating facilities at full capacity due to damage caused by a catastrophic event, our revenues could decrease due to decreased sales and our expenses could increase due to the need to obtain energy from more expensive sources. Further, we self-insure many risks and current and future insurance coverage may not be sufficient to replace lost revenue or cover repair and replacement costs. Any reduction of revenues for such reason, or any other reduction of our revenues or increase in our expenses resulting from the risks described above could adversely affect our financial results.

Potential terrorist activities or military or other actions could adversely affect us.

The continued threat of terrorism since September 11, 2001 and the impact of military and other actions by the United States and its allies has led to increased political, economic and financial market instability and has subjected our operations to increased risks. The United States government has issued warnings that energy assets, specifically including electric utility infrastructure, are potential targets for terrorist organizations. Political, economic or financial market instability or damage to our operating assets or the assets of our customers or suppliers may result in business interruptions, lost revenue, higher commodity prices, disruption in fuel supplies, lower energy consumption and unstable markets, increased security, repair or other costs that may materially adversely affect us in ways that cannot be predicted at this time. Any of these risks could materially affect our financial results. Furthermore, instability in the financial markets as a result of terrorism or war could also materially adversely affect our ability to raise capital.

The insurance industry may change to reflect increased instability in the political, economic and financial markets. As a result, insurance covering risks we typically insure against may decrease in scope and availability, and we may elect to self-insure against many such risks. In addition, the available insurance may have higher deductibles, higher premiums and more restrictive policy terms.

A downgrade in our credit ratings could negatively affect our access to capital, increase the cost of borrowing or raise energy transaction credit support requirements.

Our debt securities and preferred stock are rated investment grade by various rating agencies but may not continue to be rated investment grade in the future. Although none of our outstanding debt has rating-downgrade triggers that would accelerate a repayment obligation, a credit rating downgrade would increase our borrowing costs and commitment fees on our revolving credit agreements and other financing arrangements, perhaps significantly. In addition, we would likely be required to pay a higher interest rate in future financings, and the potential pool of investors and funding sources would likely decrease. Further, access to the commercial paper market, our principal source of short-term borrowings, could be significantly limited, resulting in higher interest costs. The commercial paper market has been disrupted as a result of the recent economic conditions, which could also limit our ability to access commercial paper.

Most of our large customers, suppliers and counterparties require sufficient creditworthiness in order to enter into transactions, particularly in the wholesale energy markets. If our credit ratings were to decline, especially below investment grade, financing costs and borrowings would likely increase because counterparties may require a letter of credit, collateral in the form of cash-related instruments or some other security as a condition to further transactions with us.

We have a substantial amount of debt, which could adversely affect our ability to obtain future financing and limit our expenditures.

As of December 31, 2008, we had $5.6 billion in total debt securities outstanding. Our principal financing agreements contain restrictive covenants that limit our ability to borrow funds, and any issuance of debt securities requires prior authorization from certain of our state regulatory commissions. We expect that we 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, we may postpone planned capital expenditures, or take other actions, to the extent those expenditures are not fully covered by cash from operations, borrowings under committed credit facilities or equity contributions from MEHC.

MEHC may exercise its significant influence over us in a manner that would benefit MEHC to the detriment of our creditors and preferred stockholders.

MEHC, through its subsidiary, owns all of our common stock and generally has control over the election of our directors and all decisions requiring shareholder approval. In circumstances involving a conflict of interest between MEHC and our creditors and preferred stockholders, MEHC could exercise its control in a manner that would benefit MEHC to the detriment of our creditors and preferred stockholders.

Poor performance of plan and fund investments and other factors impacting the pension plan, the other postretirement benefits plan and mine reclamation costs could unfavorably impact our cash flows and liquidity.

Costs of providing our non-contributory defined benefit pension and other postretirement benefits plans depend upon a number of factors, including the rates of return on plan assets, the level and nature of benefits provided, discount rates, the interest rates used to measure required minimum funding levels, changes in benefit design, changes in laws and government regulation and our required or voluntary contributions made to the plans. Our pension and other postretirement benefits plans are in underfunded positions. The recent declines in the global financial markets have exacerbated our plans' underfunded positions. Even with sustained growth in the investments over future periods to increase the value of these plans' assets, we will likely be required to make significant cash contributions to fund these plans. Furthermore, the recently enacted Pension Protection Act of 2006 may result in more volatility in the amount and timing of future contributions. Similarly, funds dedicated to mine reclamation are also invested in equity and fixed income securities, and poor performance of these investments will reduce the amount of funds available for their intended purpose, which would require us to make additional cash contributions. Such cash funding obligations, which are also impacted by the other factors described above, could have a material impact on our liquidity by reducing our cash flows.

We are involved in numerous legal proceedings, the outcomes of which are uncertain and could adversely affect our financial results.

We are party to numerous legal proceedings. Litigation is subject to many uncertainties, and we cannot predict the outcome of individual matters. It is possible that the final resolution of some of the matters in which we are involved could result in additional payments in excess of established reserves over an extended period of time and in amounts that could have a material adverse effect on our financial results. Similarly, it is also possible that the terms of resolution could require that we change business practices and procedures, which could also have a material adverse effect on our financial results. Further, litigation could result in the imposition of financial penalties or injunctions which could limit our ability to take certain desired actions or the denial of needed permits, licenses or regulatory authority to conduct our business, including the siting or permitting of facilities. Any of these outcomes could adversely affect our financial results.

Potential changes in accounting standards might cause us to revise our financial results and disclosure in the future, which may change the way analysts measure our business or financial performance.

Accounting irregularities discovered in the past few years in various industries have caused regulators and legislators to take a renewed look at accounting practices, financial disclosures, companies' relationships with their independent auditors and the accounting for defined benefit plans. Because it is still unclear what laws or regulations will ultimately develop, we cannot predict the ultimate impact of any future changes in accounting regulations or practices in general with respect to public companies or the energy industry or in our operations specifically. In addition, the Financial Accounting Standards Board ("FASB"), the FERC or the SEC could enact new or revised accounting standards or FERC orders that might impact how we are required to record revenues, expenses, assets and liabilities.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

PacifiCorp's properties consist of the physical assets necessary to generate, transmit, distribute and supply energy and consist mainly of electric generation, transmission and distribution facilities, along with the related rights-of-way. It is the opinion of PacifiCorp's management that the principal depreciable properties owned by PacifiCorp are in good operating condition and are well maintained. Substantially all of PacifiCorp's electric utility properties are subject to the lien of PacifiCorp's Mortgage and Deed of Trust. Refer to Exhibit 4.1 in Item 15 of this Form 10-K. For additional information regarding PacifiCorp's properties, refer to Item 1 of this Form 10-K and Notes 3 and 4 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

The right to construct and operate PacifiCorp's transmission and distribution facilities across certain property was obtained in most circumstances through negotiations and, where necessary, through the exercise of the power of eminent domain. PacifiCorp continues to have the power of eminent domain in each of the jurisdictions in which it operates, but it does not have the power of eminent domain with respect to Native American tribal lands.

With respect to real property, each of the transmission and distribution facilities fall into two basic categories: (1) parcels that are owned in fee, such as certain of the generation facilities, substations and office sites; and (2) parcels where the interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for the construction, operation and maintenance of the transmission and distribution facilities. PacifiCorp believes that it has satisfactory title to all of the real property making up its respective facilities in all material respects.

Headquarters/Offices

PacifiCorp's corporate offices consist of approximately 800,000 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 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 facilities.

ITEM 3. LEGAL PROCEEDINGS

In addition to the proceedings described below, PacifiCorp is currently party to various items of litigation or arbitration in the normal course of business, none of which are reasonably expected by PacifiCorp to have a material adverse effect on its consolidated financial results.

In February 2007, the Sierra Club and the Wyoming Outdoor Council filed a complaint against PacifiCorp in the federal district court in Cheyenne, Wyoming, alleging violations of the Wyoming state opacity standards at PacifiCorp's Jim Bridger plant in Wyoming. Under Wyoming state requirements, which are part of the Jim Bridger plant's Title V permit and are enforceable by private citizens under the federal Clean Air Act, a potential source of pollutants such as a coal-fired generating facility must meet minimum standards for opacity, which is a measurement of light that is obscured in the flue of a generating facility. The complaint alleges thousands of violations of asserted six-minute compliance periods and seeks an injunction ordering the Jim Bridger plant's compliance with opacity limits, civil penalties of $32,500 per day per violation, and the plaintiffs' costs of litigation. The court granted a motion to bifurcate the trial into separate liability and remedy phases. In March 2008, the court indefinitely postponed the date for the liability-phase trial. The remedy-phase trial has not yet been scheduled. The court also has before it a number of motions on which it has not yet ruled. PacifiCorp believes it has a number of defenses to the claims. PacifiCorp intends to vigorously oppose the lawsuit but cannot predict its outcome at this time. PacifiCorp has already committed to invest at least $812 million in pollution control equipment at its generating facilities, including the Jim Bridger plant. This commitment is expected to significantly reduce system-wide emissions, including emissions at the Jim Bridger plant.

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 was 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 plant. USA Power's complaint alleged that PacifiCorp misappropriated confidential proprietary information in violation of Utah's Uniform Trade Secrets Act and accused PacifiCorp of breach of contract and related claims. USA Power seeks $250 million in damages, statutory doubling of damages for its trade secrets violation claim, punitive damages, costs and attorneys' fees. After considering various motions for summary judgment, the court ruled in October 2007 in favor of PacifiCorp on all counts and dismissed the plaintiffs' claims in their entirety. In February 2008, the plaintiffs filed a petition requesting consideration of their appeal by the Utah Supreme Court. The plaintiff's request was granted and they filed a brief in November 2008 with the Utah Supreme Court. In January 2009, PacifiCorp filed its reply brief. PacifiCorp believes that its defenses that prevailed in the trial court will prevail on appeal. Furthermore, PacifiCorp expects that the outcome of any appeal will not have a material impact on its consolidated financial results.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

MEHC indirectly owns all of the shares of PacifiCorp's outstanding common stock. Therefore, there is no public market for PacifiCorp's common stock. PacifiCorp did not pay dividends on common stock during the years ended December 31, 2008 and 2007. PacifiCorp does not expect to declare or pay dividends on common stock during the year ending December 31, 2009.

During the years ended December 31, 2008 and 2007, PacifiCorp received capital contributions of $450 million and $200 million, respectively, in cash from its indirect parent company, MEHC.

For a discussion of regulatory restrictions that limit PacifiCorp's ability to pay dividends on common stock, refer to Note 15 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth PacifiCorp's selected consolidated historical financial data, which should be read in conjunction with Item 7 of this Form 10-K and with PacifiCorp's historical Consolidated Financial Statements and notes thereto in Item 8 of this Form 10-K. The selected consolidated historical financial data has been derived from PacifiCorp's audited historical Consolidated Financial Statements and notes thereto (in millions). In May 2006, the PacifiCorp Board of Directors elected to change PacifiCorp's fiscal year-end from March 31 to December 31.

	Years Ended December 31,		Nine-Month Period Ended December 31,	Years Ended March 31,	
	2008	**2007**	**2006**	**2006**	**2005**
Consolidated Statement of Operations Data:					
Operating revenue	$ 4,498	$ 4,258	$ 2,924	$ 3,897	$ 3,049
Operating income	947	888	415	792	656
Net income	458	439	161	361	252

	As of December 31,			As of March 31,	
	2008	**2007**	**2006**	**2006**	**2005**
Consolidated Balance Sheet Data:					
Total assets	$ 17,167	$ 14,907	$ 13,852	$ 12,731	$ 12,521
Long-term debt and capital lease obligations, excluding current portion	5,424	4,753	3,967	3,721	3,629
Preferred stock subject to mandatory redemption, excluding current portion	-	-	-	41	49
Preferred stock	41	41	41	41	41
Total shareholders' equity	5,987	5,080	4,426	4,052	3,377

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following is management's discussion and analysis of certain significant factors that have affected the financial condition and results of operations of PacifiCorp during the periods included herein. Explanations include management's best estimate of the impacts of weather, customer growth and other factors. This discussion should be read in conjunction with Item 6 of this Form 10-K and with PacifiCorp's historical Consolidated Financial Statements and notes thereto in Item 8 of this Form 10-K. PacifiCorp's actual results in the future could differ significantly from the historical results.

RESULTS OF OPERATIONS

As a result of PacifiCorp's election to change its fiscal year from March 31 to December 31, the audited periods presented in the Consolidated Statements of Operations include the years ended December 31, 2008 and 2007 and the nine-month transition period ended December 31, 2006. To facilitate a better understanding of PacifiCorp's results of operations and business trends, the following discussion is based on the comparison of the audited year ended December 31, 2008 to the audited year ended December 31, 2007 and the audited year ended December 31, 2007 to the unaudited year ended December 31, 2006. Financial information for the year ended December 31, 2006 is derived from PacifiCorp's audited consolidated financial statements for the nine-month transition period ended December 31, 2006 and PacifiCorp's unaudited consolidated financial statements for the three-month period ended March 31, 2006.

Overview

PacifiCorp's net income increased $19 million to $458 million for 2008 compared with 2007, primarily due to higher revenues in the current year, significantly offset by higher fuel costs.

Retail revenue increased $198 million for 2008 compared with 2007, primarily due to higher prices approved by regulators to recover increased costs due to assets placed in service and higher net power costs, growth in the average number of residential and commercial customers and higher average customer usage. Retail energy sales volumes grew by 2% in 2008 compared with 2007. Customer usage levels began to decline in the fourth quarter of 2008 due to the effects of the current economic conditions in the United States and around the world. This declining usage trend may continue in 2009.

Wholesale sales and other revenue for 2008 increased $42 million compared with 2007, primarily due to higher contract prices for transmission services and higher average prices on wholesale electric sales, substantially offset by lower volumes.

Overall, total retail and wholesale sales volumes were relatively flat for 2008 compared with 2007.

PacifiCorp added 1,068 MW of gas-fired generating capacity during the past two years through the additions of the 548-MW Lake Side plant in September 2007 and the 520-MW Chehalis plant in September 2008. PacifiCorp also increased its renewable generating capacity by the construction and commissioning of 382 MW of wind-powered generating facilities. These additions to generating capacity have enabled PacifiCorp to significantly reduce its reliance on purchased electricity to meet its retail load requirements.

Fuel costs increased $182 million for 2008 compared with 2007, primarily due to higher average prices for natural gas and coal. Increases in generating capacity across all resource types enabled PacifiCorp to accommodate the increased retail loads during 2008 and reduce its purchased electricity costs by $35 million compared with 2007 despite a 14% increase in the average wholesale price.

Output from PacifiCorp's coal-fired generating facilities increased by 254,500 MWh, or 1%, for 2008 compared with 2007. Output from PacifiCorp's natural gas-fired generating facilities increased by 856,086 MWh, or 11%, for 2008 compared with 2007, due to the additions of the 548-MW Lake Side plant and the 520-MW Chehalis plant. Output from PacifiCorp's hydroelectric generating facilities increased by 18,195 MWh, or 1%, for 2008 compared with 2007. PacifiCorp's hydroelectric generation was 90% of normal for both 2008 and 2007, based on a 30-year average.

PacifiCorp's net income increased $131 million to $439 million for 2007 compared with 2006. The $131 million increase in net income was primarily due to higher retail revenues and higher net wholesale sales and purchases, partially offset by higher fuel costs.

Retail revenue increased $292 million for 2007 compared with 2006, primarily due to higher prices approved by regulators to recover increased costs due to assets placed in service and higher net power costs, growth in the average number of residential and commercial customers and higher average customer usage. Retail energy sales volumes grew by 3% in 2007 compared with 2006.

Wholesale sales and other revenue increased $126 million for 2007 compared with 2006, due to higher average prices on wholesale electric sales. This increase was more than offset by $313 million of decreases due to changes in the fair value of energy sales contracts accounted for as derivatives.

Fuel costs increased $287 million for 2007 compared with 2006, primarily due to increases in the average prices of natural gas and coal, as well as higher volumes of natural gas consumed. This increase was more than offset by $364 million of decreases due to changes in the fair value of energy purchase contracts accounted for as derivatives.

Output from PacifiCorp's coal-fired generating facilities increased 1,390,751 MWh, or 3%, for 2007 compared with 2006. Output from PacifiCorp's natural gas-fired generating facilities increased 3,699,169 MWh, or 88%, for 2007 compared with 2006 due to the addition of the 548-MW Lake Side plant in September 2007. Output from PacifiCorp-owned hydroelectric facilities decreased 872,509 MWh, or 19%, for 2007 compared with 2006 due to lower water flow conditions. PacifiCorp's hydroelectric generation was 90% and 111% of normal for 2007 and 2006, respectively, based on a 30-year average.

Year Ended December 31, 2008 Compared to Year Ended December 31, 2007

Operating revenue (dollars in millions)

	Years Ended December 31,		Favorable/(Unfavorable)	
	2008	2007	Change	% Change
Retail	$ 3,449	$ 3,251	$ 198	6%
Wholesale sales and other	1,049	1,007	42	4
Total operating revenue	$ 4,498	$ 4,258	$ 240	6
Average retail customers (in thousands)	1,706	1,684	22	1
Retail energy sales (GWh)	54,362	53,390	972	2
Wholesale energy sales (GWh)	12,345	13,724	(1,379)	(10)
Total energy sales (GWh)	66,707	67,114	(407)	(1)

Retail revenues increased $198 million, or 6%, primarily due to:

- $102 million of increases from higher prices approved by regulators;
- $48 million of increases related to growth in the average number of residential and commercial customers;
- $27 million of increases due to the recognition of revenues as a result of approval from the OPUC to collect previously under-collected income taxes pursuant to SB 408; and
- $21 million of increases due to higher average customer usage.

Wholesale sales and other revenues increased $42 million, or 4%, primarily due to:

- $19 million of increases in transmission revenue primarily due to higher contract prices;
- $13 million of increases due to higher average prices on wholesale electric sales, substantially offset by lower volumes; and
- $6 million of increases due to changes in the fair value of energy sales contracts accounted for as derivatives.

Operating Costs and Expenses (in millions)

	Years Ended December 31,		Favorable/(Unfavorable)	
	2008	2007	Change	% Change
Energy costs	$ 1,957	$ 1,768	$ (189)	(11)%
Operations and maintenance	992	1,004	12	1
Depreciation and amortization	490	497	7	1
Taxes, other than income taxes	112	101	(11)	(11)
Total operating costs and expenses	$ 3,551	$ 3,370	$ (181)	(5)

Energy costs increased $189 million, or 11%, primarily due to:

- $141 million of natural gas cost increases substantially due to higher average prices;
- $41 million of coal cost increases substantially due to higher average prices;
- $27 million of increases primarily due to the amortization of incurred power costs deferred in the prior year in accordance with established adjustment mechanisms;
- $15 million of increases in transmission costs primarily due to new contracts; and
- $7 million of increases due to changes in the fair value of energy purchases contracts accounted for as derivatives; partially offset by,
- $35 million of decreases due to a significant decrease in purchased electricity volumes, partially offset by higher average prices; and
- $6 million of decreases due to deferral of power costs incurred in 2005 as a result of decreased hydroelectric generation, which were approved by the WUTC for recovery over a three-year period starting October 2008.

Operations and maintenance expense decreased $12 million, or 1%, primarily due to:

- $27 million of decreases in employee expenses, substantially due to lower pension and other postretirement benefit expenses; partially offset by,
- $10 million of increases in demand-side management expense primarily due to increased spending in Oregon and Idaho; and
- $5 million of increases in bad debt expense, primarily in the commercial and industrial customer classes as a result of current economic conditions.

Depreciation and amortization expense decreased $7 million, or 1%, primarily due to a $47 million reduction from the extension of the depreciable lives of certain property, plant and equipment as a result of PacifiCorp's recent depreciation study, substantially offset by higher plant-in-service in the current year.

Taxes other than income taxes increased $11 million, or 11%, primarily due to increased levels of assessable property.

Other Income (Expense) (in millions)

	Years Ended December 31,		Favorable/(Unfavorable)	
	2008	2007	Change	% Change
Interest expense	$ (343)	$ (314)	$ (29)	(9)%
Allowance for borrowed funds	34	29	5	17
Allowance for equity funds	47	41	6	15
Interest income	11	15	(4)	(27)
Total other income (expense)	$ (251)	$ (229)	$ (22)	(10)

Interest expense increased $29 million, or 9%, primarily due to higher average debt outstanding, partially offset by lower average rates on variable-rate debt during 2008.

Allowance for borrowed and equity funds increased $11 million, or 16%, primarily due to higher qualified construction work-in-progress balances, partially offset by lower average rates during 2008.

Income Tax Expense

Income tax expense increased $18 million, or 8%, to $238 million for 2008 compared with 2007, primarily due to higher pre-tax earnings combined with lower tax benefits associated with tax years under examination by the United States Internal Revenue Service (the "IRS"), amortization of federal investment tax credits and the domestic production activities deduction; partially offset by higher production tax credits associated with increased production at wind-powered generating facilities. The effective tax rates were 34% and 33% for 2008 and 2007, respectively.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006

To facilitate a better understanding of PacifiCorp's results of operations and business trends, the following discussion is based on the comparison of the audited year ended December 31, 2007 to the unaudited year ended December 31, 2006. Financial information for the year ended December 31, 2006 is derived from PacifiCorp's audited consolidated financial statements for the nine-month transition period ended December 31, 2006 and PacifiCorp's unaudited consolidated financial statements for the three-month period ended March 31, 2006.

Operating Revenue (dollars in millions)

	Years Ended December 31,		Favorable/(Unfavorable)	
	2007	2006	Change	% Change
Retail	$ 3,251	$ 2,959	$ 292	10%
Wholesale sales and other	1,007	1,195	(188)	(16)
Total operating revenue	$ 4,258	$ 4,154	$ 104	3
Average retail customers (in thousands)	1,684	1,649	35	2
Retail energy sales (GWh)	53,390	51,797	1,593	3
Wholesale energy sales (GWh)	13,724	13,657	67	-
Total energy sales (GWh)	67,114	65,454	1,660	3

Retail revenues increased $292 million, or 10%, primarily due to:

- $187 million of increases from higher prices approved by regulators;
- $54 million of increases due to higher average customer usage, primarily as a result of weather conditions; and
- $53 million of increases related to growth in the average number of residential and commercial customers, primarily in Utah and Oregon.

Wholesale sales and other revenues decreased $188 million, or 16%, primarily due to:

- $313 million of decreases due to changes in the fair value of energy sales contracts accounted for as derivatives; partially offset by,
- $126 million of increases due to higher average prices on wholesale electric sales.

Operating Costs and Expenses (in millions)

	Years Ended December 31,		Favorable/(Unfavorable)	
	2007	2006	Change	% Change
Energy costs	$ 1,768	$ 1,845	$ 77	4%
Operations and maintenance	1,004	1,054	50	5
Depreciation and amortization	497	468	(29)	(6)
Taxes, other than income taxes	101	101	-	-
Total operating costs and expenses	$ 3,370	$ 3,468	$ 98	3

Energy costs decreased $77 million, or 4%, primarily due to:

- $364 million of decreases due to changes in the fair value of energy purchase contracts accounted for as derivatives;
- $25 million of decreases primarily due to the deferral of incurred power costs in accordance with established adjustment mechanisms; and
- $13 million of decreases due to the prior period loss on the streamflow weather derivative contract; partially offset by,
- $208 million of natural gas cost increases due to higher average prices and volumes consumed;
- $79 million of coal cost increases substantially due to higher average prices;
- $24 million of increases due to higher average prices of purchased electricity, substantially offset by lower volumes of purchased electricity; and
- $13 million of increases in transmission costs primarily due to new contracts.

Operations and maintenance expense decreased $50 million, or 5%, primarily due to:

- $36 million of decreases in employee severance costs;
- $27 million of decreases in employee expenses, substantially due to reduced workforce; and
- $10 million of decreases due to the assessment of penalties related to compliance with the FERC standards of conduct for transmission in the prior period; partially offset by
- $28 million of increases in maintenance costs and related contracts, primarily associated with generating facility overhauls.

Depreciation and amortization expense increased $29 million, or 6%, primarily due to increases in production plant assets placed in service during 2007.

Other Income (Expense) (in millions)

	Years Ended December 31,		Favorable/(Unfavorable)	
	2007	2006	Change	% Change
Interest expense	$ (314)	$ (284)	$ (30)	(11)%
Allowance for borrowed funds	29	23	6	26
Allowance for equity funds	41	23	18	78
Interest income	15	8	7	88
Other, net	-	8	(8)	(100)
Total other income (expense)	$ (229)	$ (222)	$ (7)	(3)

Interest expense increased $30 million, or 11%, primarily due to higher average debt outstanding during 2007.

Allowance for borrowed and equity funds increased $24 million, or 52%, primarily due to applying higher prescribed allowance for funds used during construction ("AFUDC") rates to higher qualified construction work-in-progress balances during 2007.

Income Tax Expense

Income tax expense increased $64 million, or 41%, to $220 million for 2007, primarily due to higher pre-tax earnings. The effective tax rates were 33% and 34% for 2007 and 2006, respectively.

LIQUIDITY AND CAPITAL RESOURCES

To facilitate a better understanding of PacifiCorp's results of operations and business trends, certain portions of the following discussion are based on the comparison of the audited year ended December 31, 2007 to the unaudited year ended December 31, 2006. Financial information for the year ended December 31, 2006 is derived from PacifiCorp's audited consolidated financial statements for the nine-month transition period ended December 31, 2006 and PacifiCorp's unaudited consolidated financial statements for the three-month period ended March 31, 2006.

Sources and Uses of Cash

PacifiCorp depends on both internal and external sources of liquidity to provide working capital and to fund capital requirements. To the extent funds are not available to support capital expenditures, projects may be delayed or canceled and operating income may be reduced. 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 long-term debt issuances and through cash capital contributions from PacifiCorp's indirect parent company, MEHC. PacifiCorp expects it will need additional periodic equity contributions from its indirect parent company over the next several years. Issuance of long-term securities is influenced by levels of short-term debt, cash flows from operating activities, capital expenditures, market conditions, regulatory approvals and other considerations.

As of December 31, 2008, PacifiCorp's total net liquidity available was $1.1 billion. The components of total net liquidity available are as follows (in millions):

Cash and cash equivalents	$	59
Available revolving credit facilities	$	1,395
Less:		
Short-term borrowings and issuance of commercial paper		(85)
Letters of credit and support for variable-rate tax-exempt bond obligations		(258)
Net revolving credit facilities available	$	1,052
Total net liquidity available	$	1,111
Unsecured revolving credit facilities:		
Maturity date		2012-2013
Largest single bank commitment as a % of total		15%

An inability of financial institutions to honor their commitments could adversely affect PacifiCorp's short-term liquidity and ability to meet long-term commitments.

Operating Activities

Net cash flows provided by operating activities increased $168 million to $992 million during the year ended December 31, 2008, compared to $824 million during the year ended December 31, 2007, primarily due to higher retail revenues and lower current income tax expense, primarily due to the impact of bonus depreciation; partially offset by higher fuel costs and increased net cash collateral deposited with counterparties.

Net cash flows provided by operating activities increased $72 million to $824 million during the year ended December 31, 2007, compared to $752 million during the year ended December 31, 2006, primarily due to higher retail revenues and higher net wholesale sales and purchases, partially offset by the timing of payments and cash collections and higher fuel costs.

Investing Activities

Net cash used in investing activities increased $579 million to $2.1 billion during the year ended December 31, 2008, compared to $1.5 billion during the year ended December 31, 2007, primarily due to PacifiCorp's acquisition of Chehalis Power Generating, LLC for a cash purchase price of $308 million in September 2008 and a $270 million increase in capital expenditures.

PacifiCorp acquired from TNA Merchant Projects, Inc., an affiliate of Suez Energy North America, Inc., 100% of the equity interests of Chehalis Power Generating, LLC, an entity owning a 520-MW natural gas-fired generating plant located in Chehalis, Washington. Chehalis Power Generating, LLC was merged into PacifiCorp immediately following the acquisition.

Actual capital expenditures, excluding the non-cash allowance for equity funds used during construction ("equity AFUDC"), were $1.8 billion during the year ended December 31, 2008 compared to $1.5 billion during the year ended December 31, 2007 and included the following:

- Ongoing operations projects, excluding the non-cash equity AFUDC, were $640 million and included new connections related to customer growth.

- Generation development, excluding the non-cash equity AFUDC, totaled $805 million. These expenditures were substantially driven by the development of PacifiCorp's wind-powered generating facility portfolio and included the remaining costs for five wind-powered generating facilities totaling 382 MW placed in service during the year ended December 31, 2008. The expenditures also included the construction costs for the development of three wind-powered generating facilities, of which 138 MW were placed in service in January 2009 and an additional 99 MW are expected to be placed in service by the end of 2009.
- Transmission system expansion and upgrades, excluding the non-cash equity AFUDC, were $130 million and included costs for the construction of a 135-mile, double-circuit, 345-kilovolt transmission line to be built between the Populus substation located in southern Idaho and the Terminal substation located in the Salt Lake City area, one of the first major segments of the Energy Gateway Transmission Expansion Project, which is discussed below in "Capital Expenditures for Fiscal Years 2009 Through 2011." This transmission line will be constructed in the Path C Transmission corridor, a primary transmission corridor in PacifiCorp's balancing authority area. PacifiCorp expects to complete construction of this line in 2010. Effective September 2008, PacifiCorp executed the engineering, procurement and construction agreement for the Populus to Terminal segment. PacifiCorp is committed to making additional progress payments beyond 2008 for the construction of the Populus to Terminal segment totaling $519 million.
- Emissions control equipment, excluding the non-cash equity AFUDC, totaled $214 million and included the remaining installation costs for emission control equipment placed in service at the Cholla plant in May 2008, as well as capital expenditures at the Dave Johnston plant related to the addition of a new sulfur dioxide scrubber on Unit 3 and the replacement of an existing scrubber on Unit 4, which are expected to be placed into service during 2010 and 2012, respectively.

Net cash used in investing activities increased $105 million to $1.5 billion during the year ended December 31, 2007, compared to $1.4 billion during the year ended December 31, 2006, primarily due to higher capital expenditures. Capital expenditures totaled $1.5 billion during the year ended December 31, 2007, compared to $1.4 billion during the year ended December 31, 2006. Capital spending increased primarily due to wind-powered generating facility investments of $575 million, including the completion of the 140-MW Marengo wind-powered generating plant and additional investments for the Goodnoe Hills, Marengo II, Glenrock, Rolling Hills and Seven Mile Hill wind-powered generating facilities. Additional increases resulted from the construction of various capital projects related to transmission, distribution and other generating facilities. These increases were partially offset by decreases in expenditures as compared to the previous year for the construction of the 548-MW Lake Side plant, which commenced full combined-cycle operation in September 2007.

Financing Activities

Short-Term Debt and Revolving Credit Agreements

PacifiCorp's short-term debt increased $85 million during the year ended December 31, 2008, primarily due to capital expenditures, acquisitions and scheduled maturities of long-term debt, partially offset by net cash from operating activities, proceeds from the issuance of long-term debt, utilization of temporary cash investments and $450 million of capital contributions received during the period.

Regulatory authorities limit PacifiCorp to $1.5 billion of short-term debt, of which an aggregate principal amount of $85 million was outstanding as of December 31, 2008, with a weighted-average interest rate of 1.0%. In January 2009, PacifiCorp repaid its outstanding short-term debt with proceeds from its January 2009 long-term debt issuance discussed below.

PacifiCorp had no short-term debt outstanding as of December 31, 2007, a decrease of $397 million compared to December 31, 2006. The decrease in short-term debt was primarily due to the proceeds from the issuance of long-term debt and the capital contributions received during the year, partially offset by capital expenditures and maturities of long-term securities in excess of net cash provided by operating activities.

For further discussion, refer to Note 8 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Long-Term Debt

In addition to the debt issuances discussed herein, PacifiCorp made scheduled repayments on long-term debt totaling $412 million and $126 million during the years ended December 31, 2008 and 2007, respectively, and $211 million during the nine-month period ended December 31, 2006.

In January 2009, PacifiCorp issued $350 million of its 5.50% First Mortgage Bonds due January 15, 2019 and $650 million of its 6.00% First Mortgage Bonds due January 15, 2039.

In July 2008, PacifiCorp issued $500 million of its 5.65% First Mortgage Bonds due July 15, 2018 and $300 million of its 6.35% First Mortgage Bonds due July 15, 2038.

In March 2007, PacifiCorp issued $600 million of its 5.75% First Mortgage Bonds due April 1, 2037.

In October 2007, PacifiCorp issued $600 million of its 6.25% First Mortgage Bonds due October 15, 2037.

In August 2006, PacifiCorp issued $350 million of its 6.10% Series of First Mortgage Bonds due August 1, 2036.

In September 2008, PacifiCorp acquired $216 million of its insured variable-rate tax-exempt bond obligations due to the significant reduction in market liquidity for insured variable-rate obligations. In November 2008, the associated insurance and related standby bond purchase agreements were terminated and these variable-rate long-term debt obligations were remarketed with credit enhancement and liquidity support provided by $220 million of letters of credit issued under PacifiCorp's two unsecured revolving credit facilities.

As of December 31, 2008, PacifiCorp had $517 million of letters of credit available to provide credit enhancement and liquidity support for variable-rate tax-exempt bond obligations totaling $504 million plus interest. These committed bank arrangements were fully available at December 31, 2008 and expire periodically through May 2012.

In January 2008, PacifiCorp received regulatory authority from the OPUC and the IPUC to issue up to an additional $2.0 billion of long-term debt. PacifiCorp must make a notice filing with the WUTC prior to any future issuance. Also in January 2008, PacifiCorp filed a shelf registration statement with the SEC covering future first mortgage bond issuances. PacifiCorp's long-term debt issuances in January 2009 and during the year ended December 31, 2008 were covered under the above-noted regulatory authorities and shelf registration statement.

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 or deposits of cash. The amount of bonds that PacifiCorp may issue generally is also subject to a net earnings test. As of December 31, 2008, PacifiCorp estimated it would be able to issue up to $4.8 billion of new first mortgage bonds under the most restrictive issuance test in the mortgage. Any issuances are 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 or deposits of cash.

PacifiCorp may from time to time seek to acquire its outstanding securities through cash purchases in the open market, privately negotiated transactions or otherwise. Any debt securities repurchased by PacifiCorp may be reissued or resold by PacifiCorp from time to time and will depend on prevailing market conditions, PacifiCorp's liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Preferred Stock Redemptions

During the year ended December 31, 2007, PacifiCorp redeemed 375,000 shares totaling $38 million of its $7.48 No Par Serial Preferred Stock Series, representing the remaining outstanding shares of preferred stock subject to mandatory redemption.

PacifiCorp redeemed 75,000 shares totaling $8 million of preferred stock subject to mandatory and optional redemption during the nine-month period ended December 31, 2006.

Common Shareholder's Equity

Cash capital contributions from PacifiCorp's indirect parent company, MEHC, were $450 million and $200 million during the years ended December 31, 2008 and 2007, respectively, and $215 million during the nine-month period ended December 31, 2006.

Capitalization

PacifiCorp manages its capitalization and liquidity position to maintain a prudent capital structure with an objective of retaining strong investment grade 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, customers and creditors and provide a competitive cost of capital and predictable capital market access.

As a result of accounting standards, such as FASB Interpretation No. 46R, *Consolidation of Variable-Interest Entities, an interpretation of Accounting Research Bulletin No. 51* ("FIN 46R"), and Emerging Issues Task Force 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 equity contributions from its indirect parent company, MEHC, or take other actions.

Future Uses of Cash

PacifiCorp expects to have available a variety of sources of liquidity and capital resources, both internal and external, including cash flows from operations, public and private debt offerings, the issuance of commercial paper, the use of unsecured revolving credit facilities, capital contributions and other sources. These sources are expected to provide funds required for current operations, capital expenditures, debt retirements and other capital requirements. The availability and terms under which PacifiCorp has access to external financing depends on a variety of factors, including PacifiCorp's credit ratings, investors' judgment of risk and conditions in the overall capital markets, including the condition of the utility industry in general.

In the United States and most other economies around the world, market and economic conditions have been unprecedented and challenging compared to recent history, with more restrictive credit conditions and slowing or contracting growth during 2008. Continued concerns about the availability and cost of credit, the United States mortgage market and a declining real estate market in the United States have contributed to increased market volatility and diminished expectations for the United States economy. During the second half of 2008, a number of large financial institutions were unable to survive as independent institutions and others were forced to file for bankruptcy. Other surviving institutions required multibillion dollar capital infusions. Furthermore, a number of large financial institutions' senior unsecured debt was downgraded and placed on credit watch with negative implications by credit rating agencies. In 2008, the United States federal government enacted emergency legislation in an attempt to stabilize the economy, increased the federal deposit insurance, invested billions of dollars in financial institutions and took other steps to infuse liquidity into the economy. The global nature of this credit crisis led other governments to institute similar measures. These conditions, combined with volatile oil, gas and other commodity prices, declining business and consumer confidence and increased unemployment, have contributed to volatility of unprecedented levels. More recently, the federal government enacted the American Recovery and Reinvestment Act.

As a result of these market conditions, the cost and availability of credit has been and may continue to be adversely affected by illiquid credit markets and significantly wider credit spreads. Concern about the general stability of the markets and the credit strength of counterparties has led many lenders and institutional investors to reduce, and in some cases, cease to provide funding to borrowers. Continued turbulence in the United States and international markets and economies may adversely affect PacifiCorp's liquidity and financial condition, and the liquidity and financial condition of our customers. Recently, PacifiCorp and other investment-grade regulated utilities have been able to issue debt in the capital markets. If these poor market conditions continue, it may limit PacifiCorp's ability to access the bank and debt markets to meet liquidity and capital expenditure needs, resulting in adverse effects on the timing and amount of PacifiCorp's capital expenditures, financial condition and results of operations.

Capital Expenditures for Fiscal Years 2009 Through 2011

PacifiCorp has significant future capital requirements. Capital expenditure needs are reviewed regularly by management and may change significantly as a result of these reviews, which may consider, among other factors, changes in rules and regulations, including environmental; changes in income tax laws; general business conditions; load projections; system reliability standards; the cost and efficiency of construction labor, equipment and materials; and the cost and availability of capital. Expenditures for compliance-related items such as pollution-control technologies, replacement generation, mine reclamation, hydroelectric relicensing, hydroelectric decommissioning and associated operating costs are generally incorporated into PacifiCorp's regulated retail rates. However, there can be no assurance that costs related to capital expenditures will be fully recovered from PacifiCorp's customers, either through regulated retail rates, long-term arrangements or market prices and the inability to recover these costs could adversely affect PacifiCorp's future financial results.

PacifiCorp estimates that it will spend approximately $6.1 billion on capital projects over the next three years, excluding non-cash equity AFUDC. These capital projects include new generating resources, including renewables; transmission investments; installation of emissions control equipment on existing generating facilities; and distribution investments in new connections, lines and substations. Capital projects for emissions control equipment are expected to help achieve the commitments agreed to by PacifiCorp and MEHC as described in Note 13 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Forecasted capital expenditures for the years ended December 31 are as follows (in millions):

	2009	2010	2011
Forecasted capital expenditures*:			
Generation development	$ 266	$ 219	$ 183
Transmission expansion	640	435	314
Environmental	365	365	292
Operating projects	892	1,021	1,064
Total	$ 2,163	$ 2,040	$ 1,853

* Excludes amounts for non-cash equity AFUDC.

The capital expenditure estimate for generation development projects provided above for the year ending December 31, 2009 includes the remaining construction costs for the development of the 99-MW High Plains wind-powered generating facility that is expected to be placed in service during 2009, as well as the remaining project costs related to the wind-powered generating facilities placed in service during the year ended December 31, 2008 and those placed in service in January 2009. Evaluation and development efforts are in progress related to additional prospective wind-powered generating facilities scheduled for completion after 2009.

Capital projects for transmission expansion include the Energy Gateway Transmission Expansion Project, an investment plan to build approximately 2,000 miles of new high-voltage transmission lines primarily in Wyoming, Utah, Idaho, Oregon and the desert Southwest. The plan, with an estimated cost exceeding $6.1 billion, includes projects that will address customer load growth, improve system reliability and deliver energy from new wind-powered and other renewable generating resources throughout PacifiCorp's six-state service area and the Western United States. Certain transmission segments associated with this plan are expected to be placed in service beginning 2010, with other segments placed in service through 2018, depending on siting, permitting and construction schedules. In July 2008, PacifiCorp filed a petition for declaratory order with the FERC to confirm incentive rate treatment for the Energy Gateway Transmission Expansion Project described in "Transmission and Distribution" in Item 1 of this Form 10-K. In October 2008, the FERC granted a 200-basis-point (two-percentage-point) incentive rate adder to PacifiCorp's base return on equity for seven of the eight project segments, subject to a future Section 205 rate case filing with the FERC. The FERC did not preclude PacifiCorp from filing for incentive rate treatment for the remaining segment at a future date. Also included in the above estimate is PacifiCorp's commitment for transmission and distribution investments resulting from MEHC's acquisition of PacifiCorp.

The capital expenditure estimate for environmental projects includes emissions control equipment to meet anticipated air quality and visibility targets and the reduction of sulfur dioxide emissions. This estimate includes additions at the Dave Johnston plant for a new sulfur dioxide scrubber on Unit 3 and the replacement of an existing scrubber on Unit 4, which are expected to be completed in 2010 and 2012, respectively.

Capital expenditures related to operating projects consist of recurring expenditures for distribution, transmission, generation, mining and other infrastructure needed to service existing and expected demand.

PacifiCorp is subject to federal, state and local laws and regulations with regard to air and water quality, RPS, hazardous and solid waste disposal and other environmental matters. The future costs (beyond existing planned capital expenditures) of complying with applicable environmental laws, regulations and rules cannot yet be reasonably estimated but are expected to be material to PacifiCorp. In particular, future mandates, including those associated with addressing the issue of global climate change, may impact the operation of PacifiCorp's generating facilities and may require PacifiCorp to reduce emissions at its facilities through the installation of additional emission control equipment or to purchase additional emission allowances or offsets in the future. PacifiCorp is not aware of any proven commercially available technology that eliminates or captures and stores carbon dioxide emissions from coal-fired and gas-fired generating facilities, and PacifiCorp is uncertain when, or if, such technology will be commercially available. Refer to Environmental Regulation in Item 1 of this Form 10-K for a detailed discussion of the topic.

Investment Trust Valuation

PacifiCorp sponsors a defined benefit pension plan and a postretirement benefit plan (the "Plans") that cover the majority of its employees. During the year ended December 31, 2008, the funded status of the Plans declined by $277 million. The actual loss on the plan assets for the year ended December 31, 2008 was $327 million, or 24% of the $1.3 billion fair value of plan assets held as of December 31, 2007. Changes in the fair value of plan assets did not have an impact on earnings for 2008; however, the poor performance contributed to an increase of $337 million in net regulatory assets related to amounts not yet recognized as components of net periodic benefit costs. The net regulatory asset represents amounts recoverable from customers in the future. Reduced benefit plan assets will result in increased benefit costs in future years and will increase the amount and accelerate the timing of required future funding contributions.

Obligations and Commitments

Contractual Obligations

The following table shows PacifiCorp's contractual obligations as of December 31, 2008 (in millions):

	Payments Due During the Years Ending December 31,				
	2009	2010-2011	2012-2013	Thereafter	Total
Long-term debt, including interest:					
Fixed-rate obligations	$ 449	$ 1,200	$ 747	$ 8,200	$ 10,596
Variable-rate obligations (1)	5	11	51	535	602
Short-term debt, including interest	85	-	-	-	85
Capital leases, including interest (2)	13	17	20	106	156
Operating leases	5	8	7	36	56
Asset retirement obligations (3)	27	36	13	547	623
Power purchase agreements: (4)					
Electricity commodity contracts	234	224	57	236	751
Electricity capacity contracts	164	382	255	1,215	2,016
Electricity mixed contracts	21	37	35	177	270
Transmission	80	146	122	545	893
Fuel purchase agreements: (4)					
Natural gas supply and transportation	232	330	53	124	739
Coal supply and transportation	287	365	232	982	1,866
Other purchase obligations (5)	966	533	78	128	1,705
Other long-term liabilities (6)	61	12	6	72	151
Total contractual cash obligations	$ 2,629	$ 3,301	$ 1,676	$ 12,903	$ 20,509

(1) Consists of principal and interest for tax-exempt bond obligations with interest rates scheduled to reset within the next 12 months. Future variable interest rates are set at December 31, 2008 rates. Refer to "Interest Rate Risk" in Item 7A of this Form 10-K for additional discussion related to variable-rate liabilities.

(2) Excluded from these amounts are approximately $46 million of capital lease executory costs, including taxes, maintenance and insurance.

(3) Represents expected cash payments adjusted for inflation for estimated costs to perform legally required asset retirement activities.

(4) Commodity contracts are agreements for the delivery of energy. Capacity contracts are agreements that provide rights to energy output, generally of a specified generating facility. Forecasted or other applicable estimated prices were used to determine total dollar value of the commitments for purposes of the table.

(5) Includes minimum commitments primarily for the construction, development and maintenance of generation and transmission facilities. The other purchase obligation amounts consist of items which PacifiCorp is contractually obligated to purchase from a third party as of December 31, 2008. These amounts constitute the known portion of PacifiCorp's expected future expenses. For purposes of identifying and accumulating purchase obligations, PacifiCorp has included all contracts meeting the definition of a purchase obligation (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.

(6) Includes environmental and hydroelectric relicensing commitments recorded in the Consolidated Balance Sheets that are contractually or legally binding and contributions expected to be made to the PacifiCorp Retirement Plan during 2009 as disclosed in Note 11 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K. Excludes regulatory liabilities and employee benefit plan obligations that are not legally or contractually fixed as to timing and amount. Deferred income taxes are excluded since cash payments are based primarily on taxable income for each year. Uncertain tax positions are also excluded because the amounts and timing of cash payments are not certain.

Commercial Commitments

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. In the event of default by PacifiCorp, the bonding agency would seek recovery from PacifiCorp in the amount of the bond. The majority of these bonds are continuous in nature and renew annually. Based on current contractual commitments, PacifiCorp's level of surety bonding after December 31, 2008 is estimated to be approximately $25 million per year. This estimate is based on current information and actual amounts may vary due to rate changes or changes to the general operations of PacifiCorp.

Regulatory Matters

PacifiCorp is subject to comprehensive regulation by the UPSC, the OPUC, the WPSC, the WUTC, the IPUC and the CPUC. PacifiCorp pursues a regulatory program in all states, with the objective of keeping rates closely aligned to ongoing costs. PacifiCorp has separate power cost recovery mechanisms in Oregon, Wyoming and California. The following discussion provides a state-by-state update.

Utah

In December 2007, PacifiCorp filed a general rate case with the UPSC requesting an annual increase of $161 million, or an average price increase of 11% based on a test period ended June 2009. The increase was primarily due to increased capital spending and net power costs, both of which are driven by load growth. In March 2008, PacifiCorp filed supplemental testimony reducing the requested rate increase to $100 million. The decrease was primarily a result of a UPSC-ordered change in the test period to the year ended December 2008 and reductions associated with recent UPSC orders on depreciation rate changes and two deferred accounting requests. Subsequently, hearings were held on the revenue requirement portion of the case and PacifiCorp filed additional testimony. In August 2008, the UPSC issued its revenue requirement order in the case, increasing rates by $36 million, or 3%. The new rates became effective August 13, 2008. In September 2008, PacifiCorp filed a petition for reconsideration of several elements of the order. In October 2008, the UPSC issued an order on the reconsideration petition allowing PacifiCorp to recover an additional $3 million, bringing the total rate increase to $39 million. A settlement that provides for an equal percentage increase to all tariff customers was reached in the rate-design phase of the case and was approved by the UPSC.

In July 2008, PacifiCorp filed a general rate case with the UPSC requesting an annual increase of $161 million, or an average price increase of 11%, prior to any consideration for the UPSC's order in the December 2007 case described above. In September 2008, PacifiCorp filed supplemental testimony that reflected then-current revenues and other adjustments based on the August 2008 order in the 2007 general rate case. The supplemental filing reduced PacifiCorp's request to $115 million. In October 2008, the UPSC issued an order changing the test period from the twelve months ending June 2009 using end-of-period rate base to the forecast calendar year 2009 using average rate base. In December 2008, PacifiCorp updated its filing to reflect the change in the test period. The updated filing proposes an increase of $116 million, or an average price increase of 8%. The UPSC issued an order resetting the beginning of the 240-day statutory time period required to process the case to the date of the September 2008 supplemental filing. Based on the new time period, the new rates, if approved, will become effective in May 2009. In February 2009, a settlement agreement was reached among the parties who had filed testimony in the cost of capital phase of the rate case. A stipulation was filed with the UPSC requesting that the UPSC set the weighted cost of capital at 8.4%.

Oregon

In April 2008, PacifiCorp made its first annual RAC filing to recover the revenue requirement related to eligible new renewable resources and associated transmission under the OREA that are not reflected in general rates. PacifiCorp requested an annual increase of $39 million on an Oregon-allocated basis, or an average price increase of 4%. In November 2008, the OPUC issued an order approving the RAC request with certain modifications. The OPUC excluded Oregon's share of the costs for the 99-MW Rolling Hills wind-powered generating plant from the request on the basis that PacifiCorp failed to prove the resource was prudently acquired. The OPUC's finding was primarily based on the conclusion that the capacity factor was less favorable compared to other Wyoming wind-powered generating projects. In December 2008 and January 2009, PacifiCorp submitted compliance filings consistent with the OPUC order that together reduced the requested increase by $8 million to $31 million, or an average price increase of 3%. The commission approved $25 million, or 2%, to go into effect on January 1, 2009. The commission approved an additional $6 million, or 1%, to go into effect on January 21, 2009 for the 99-MW Seven Mile Hill wind-powered generating plant.

In July 2008, as part of its annual TAM, PacifiCorp filed updated forecasted net power costs for 2009. PacifiCorp proposed a net power cost increase of $57 million on an Oregon-allocated basis, or an average price increase of 6%. In September 2008, PacifiCorp filed a stipulation agreement reducing the proposed net power cost increase to $34 million on an Oregon-allocated basis, or an average price increase of 2%. The stipulation agreement was approved by the OPUC in November 2008. The forecasted net power costs were updated again in November 2008 for OPUC-ordered changes, changes to the forward price curve and new wholesale sales and purchases. In December 2008, PacifiCorp submitted a compliance filing in the TAM proceeding that reflected final forecasted net power costs and direct access transition adjustments for 2009. The compliance filing reduced PacifiCorp's request by an additional $15 million on an Oregon-allocated basis, which resulted in an increase of $9 million, or an average price increase of 1%, after adjusting for load growth. The compliance filing was approved in December 2008 and the new rates became effective January 1, 2009.

For a discussion of SB 408, refer to Note 5 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Wyoming

In June 2007, PacifiCorp filed a general rate case with the WPSC requesting an annual increase of $36 million, or an average price increase of 8%. In addition, PacifiCorp requested approval of a new renewable resource recovery mechanism and a marginal cost pricing tariff to better reflect the cost of adding new generation. In January 2008, PacifiCorp reached a settlement in principle with parties to the case. The settlement provided for an annual rate increase of $23 million, or an average price increase of 5%. In addition, the parties also agreed to modify the current PCAM to use forecasted power costs in the future and to terminate the PCAM by April 2011, unless a continuation is specifically applied for by PacifiCorp and approved by the WPSC. PacifiCorp's marginal cost pricing tariff proposal will not be implemented, but will be the subject of a collaborative process to seek a new pricing proposal. Also as part of the settlement, PacifiCorp agreed to withdraw from this filing its request for a renewable resource recovery mechanism. The stipulation was approved by the WPSC in March 2008. The new rates were effective May 1, 2008.

In February 2008, PacifiCorp filed its annual PCAM application with the WPSC for costs incurred during the period December 1, 2006 through November 30, 2007. In March 2008, the WPSC approved PacifiCorp's request on an interim basis effective April 1, 2008, resulting in a rate increase of $31 million, or an average price increase of 8%, to recover deferred power costs over a one-year period. In August 2008, PacifiCorp reached an agreement with parties to the case to adjust the rate increase to $29 million. In November 2008, the WPSC issued an order approving the stipulation agreement. The interim rates were revised to reflect the $29 million increase approved in the stipulation agreement and became effective October 15, 2008.

In July 2008, PacifiCorp filed a general rate case with the WPSC requesting an annual increase of $34 million, or an average price increase of 7%, with an effective date in May 2009. Power costs have been excluded from the filing and will be addressed separately in PacifiCorp's annual PCAM application in February 2009. In October 2008, the general rate case request was reduced by $5 million, to $29 million, to reflect a change in the in-service date of the High Plains wind-powered generating plant.

In February 2009, PacifiCorp filed its annual PCAM application with the WPSC. Pursuant to tariff changes made in the 2007 general rate case, the 2009 PCAM application includes a request to recover $27 million of deferred net power costs during the period December 1, 2007 through November 30, 2008 and to establish a new forecast base net power cost using the test period December 1, 2008 through November 30, 2009. The net effect of the deferred and forecast base net power cost is an increase in Wyoming rates of $19 million, or 4%. The tariff governing the power cost adjustment mechanism requires an effective date of April 1, 2009.

Washington

In February 2008, PacifiCorp filed a general rate case with the WUTC for an annual increase of $35 million, or an average price increase of 15%. In August 2008, PacifiCorp filed with the WUTC an all-party settlement agreement in which the parties agreed to an overall rate increase of $20 million, or 9%. The settlement was approved by the WUTC in October 2008 with the new rates effective October 15, 2008. The increase is composed of an $18 million increase to base rates, as well as a $2 million annual surcharge for approximately three years related to recovery of higher power costs incurred in 2005 due to poor hydroelectric conditions. PacifiCorp agreed to drop the current proposal for a generation cost adjustment mechanism and further committed not to propose such a mechanism in the next general rate case.

In February 2009, PacifiCorp filed a general rate case with the WUTC for an annual increase of $39 million, or an average price increase of 15%. The expected effective date for the rate change is January 11, 2010. The filing includes a request to begin collection of a deferral for costs associated with the 520-MW Chehalis natural gas-fired generating plant prior to its inclusion in rate base beginning in January 2010. The associated costs are estimated at $15 million. PacifiCorp has proposed to recover these costs through an extension in the hydroelectric deferral mechanism and thereby not affecting current customer rates.

Idaho

In September 2008, PacifiCorp filed a general rate case with the IPUC for an annual increase of $6 million, or an average price increase of 4%. The increase is primarily due to increased capital spending and net power costs. If approved, the new rates will become effective April 18, 2009. In February 2009, a settlement signed by PacifiCorp, the IPUC staff and intervening parties was filed with the IPUC resolving all issues in the 2008 general rate case. The agreement stipulates a $4 million increase, or 3% average rate increase, for non-contract retail customers in Idaho. As part of the stipulation, intervening parties acknowledged the following: PacifiCorp's acquisition of the Chehalis, Washington plant was prudent and the investment should be included in PacifiCorp's revenue requirement; PacifiCorp has demonstrated that its demand-side management programs are prudent; and a base level of net power costs is established for any future energy cost adjustment mechanism calculations if a mechanism is adopted in Idaho. In February 2009, parties to the stipulation will file supporting testimony recommending the IPUC approve the stipulation as filed. Public hearings are scheduled in March 2009.

In October 2008, PacifiCorp filed a request with the IPUC for approval of an annual ECAM to defer for later recovery in rates the difference between base net power costs set during a general rate case and actual net power costs incurred by PacifiCorp. If approved, PacifiCorp would file an application with the IPUC annually to adjust the ECAM surcharge rate to refund or collect the ECAM deferred balance from the end of the prior calendar year.

California

In 2008, PacifiCorp made filings with the CPUC requesting rate increases pursuant to the post-test year adjustment mechanism and the energy cost adjustment clause totaling $5 million, or average price increases totaling 6%. All requests were approved by the CPUC and the rates became effective various dates from August 23, 2008 through January 1, 2009.

In February 2009, PacifiCorp filed a post test year adjustment mechanism for major capital additions amounting to a rate adjustment of $1 million, or 2%. The filing includes the addition of four major renewable resources; the 99-MW Seven Mile Hill, the 99-MW Glenrock, the 39-MW Glenrock III and the 99-MW Rolling Hills wind-powered generating facilities. The expected effective date for the price change is March 19, 2009.

Depreciation Rate Changes

In August 2007, PacifiCorp filed applications with the regulatory commissions in Utah, Oregon, Wyoming, Washington and Idaho to change its rates of depreciation prospectively based on a new depreciation study. PacifiCorp received approval to change the depreciation rates effective January 1, 2008. The OPUC order required additional modifications related to the depreciation lives of coal-fired generating facilities, which were approved in August 2008. The revised depreciation rates generally reflect an extension of the lives of PacifiCorp's assets and resulted in a benefit to pre-tax income during the year ended December 31, 2008 of approximately $47 million.

Credit Ratings

Debt and preferred securities of PacifiCorp are rated by nationally recognized credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of PacifiCorp's ability to, in general, meet the obligations of its issued debt or preferred securities. The credit ratings are not a recommendation to buy, sell or hold securities, and there is no assurance that a particular credit rating will continue for any given period of time. PacifiCorp's credit ratings at January 31, 2009 were as follows:

	Moody's	Standard & Poor's
Issuer/Corporate	Baa1	A-
Senior secured debt	A3	A-
Senior unsecured debt	Baa1	A-
Preferred stock	Baa3	BBB
Commercial paper	P-2	A-1
Outlook	Stable	Negative

PacifiCorp has no credit rating-downgrade triggers that would accelerate the maturity dates of outstanding debt and a change in ratings is not an event of default under applicable debt instruments. PacifiCorp's unsecured revolving credit facilities do not require the maintenance of a minimum credit rating level in order to draw upon their availability. However, commitment fees and interest rates under the credit facilities are tied to credit ratings and increase or decrease when the ratings change. A rating downgrade could also increase the future cost of commercial paper, short- and long-term debt issuances or new credit facilities. 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.

A change to PacifiCorp's credit rating could result in the requirement to post cash collateral, letters of credit or other similar credit support under certain agreements related to its procurement or sale of electricity, natural gas, coal and other supplies. In accordance with industry practice, PacifiCorp's agreements may 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. As of December 31, 2008, PacifiCorp's credit ratings from the three recognized credit rating agencies were investment grade; however, if the ratings fell one rating below investment grade, PacifiCorp's collateral requirements would increase by approximately $356 million. Additional collateral requirements would be necessary if ratings fell further than one rating below investment grade. PacifiCorp's collateral requirements could fluctuate considerably due to seasonality, market price volatility, a loss of key PacifiCorp generating facilities or other related factors.

Limitations

In addition to PacifiCorp's capital structure objectives, its debt capacity is also governed by its contractual and regulatory commitments.

PacifiCorp's revolving credit and other financing agreements contain customary covenants and default provisions, including a covenant not to exceed a specified debt-to-capitalization ratio of 0.65 to 1. Management believes that PacifiCorp could have borrowed an additional $5.5 billion as of December 31, 2008 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 December 31, 2008, 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. From January 1, 2009 through December 31, 2009, the minimum level of common equity required by this commitment is 47.25%. After December 31, 2009, this minimum level of common equity declines annually to 44% after December 31, 2011. The terms of this commitment treat 50% of PacifiCorp's remaining balance of preferred stock in existence prior to the acquisition of PacifiCorp by MEHC as common equity. As of December 31, 2008, PacifiCorp's actual common stock equity percentage, as calculated under this measure, was 52.6%, and PacifiCorp had $945 million available to dividend.

These commitments also restrict PacifiCorp from making any distributions to either PPW Holdings LLC or MEHC if PacifiCorp's unsecured debt is rated 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 December 31, 2008, PacifiCorp's unsecured debt was rated A- by Standard & Poor's Rating Services, BBB+ by Fitch Ratings and Baa1 by Moody's Investor Service.

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 guarantees 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 FIN 46R. 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. Refer to Notes 10 and 17 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for more information on these obligations and arrangements.

New Accounting Pronouncements

For a discussion of new accounting pronouncements affecting PacifiCorp, refer to Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Critical Accounting Policies

Certain accounting policies require management to make estimates and judgments concerning transactions that will be settled several years in the future. Amounts recognized in the Consolidated Financial Statements from such estimates are necessarily based on numerous assumptions involving varying and potentially significant degrees of judgment and uncertainty. Accordingly, the amounts currently reflected in the Consolidated Financial Statements will likely increase or decrease in the future as additional information becomes available. The following critical accounting policies are impacted significantly by judgments, assumptions and estimates used in the preparation of the Consolidated Financial Statements.

Accounting for the Effects of Certain Types of Regulation

PacifiCorp prepares its financial statements in accordance with the provisions of Statement of Financial Accounting Standards ("SFAS") No. 71, *Accounting for the Effects of Certain Types of Regulation* ("SFAS No. 71"), which differs in certain respects from the application of accounting principles generally accepted in the United States of America ("GAAP") by non-regulated businesses. In general, SFAS No. 71 recognizes that accounting for rate-regulated enterprises should reflect the economic effects of regulation. As a result, a regulated entity is required to defer the recognition of costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future rates. Accordingly, PacifiCorp has deferred certain costs and income that will be recognized in earnings over various future periods.

Management continually evaluates the applicability of SFAS No. 71 and assesses whether its regulatory assets are probable of future recovery by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation, other regulatory actions or the impact of competition, which could limit PacifiCorp's ability to recover its costs. Based upon this continual assessment, management believes the application of SFAS No. 71 continues to be appropriate and its existing regulatory assets are probable of recovery. The assessment reflects the current political and regulatory climate at both the state and federal levels and is subject to change in the future. If it becomes no longer probable that these costs will be recovered, the regulatory assets and regulatory liabilities would be written off and recognized in operating income. Total regulatory assets were $1.6 billion and total regulatory liabilities were $821 million as of December 31, 2008. Refer to Note 5 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding PacifiCorp's regulatory assets and regulatory liabilities.

Derivatives

PacifiCorp is exposed to the impact of market fluctuations in commodity prices, principally natural gas and electricity. PacifiCorp employs established policies and procedures to manage its risks associated with these market fluctuations using various commodity derivative instruments, including forward contracts, options, swaps and other agreements.

Measurement Principles

Derivative instruments are recorded in the Consolidated Balance Sheets as either assets or liabilities and are stated at fair value unless they are designated as normal purchases and normal sales and qualify for the exemption afforded by GAAP. The fair value of derivative instruments is determined using unadjusted quoted prices for identical instruments on the applicable exchange in which PacifiCorp transacts, when available, or 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 at future dates. PacifiCorp bases its forward price curves upon market price quotations, when available, or internally developed and commercial models, with internal and external fundamental data inputs. Market price quotations are obtained from independent brokers, exchanges, direct communication with market participants and actual transactions executed by PacifiCorp. Market price quotations for certain major electricity and natural gas 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 inputs. For market price quotations for other electricity and natural gas trading points that are not readily obtainable for the first six years or if the instrument is not actively traded, PacifiCorp uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on significant unobservable inputs. The fair value of these derivative instruments is a function of underlying forward commodity prices, interest rates, currency rates, related volatility, counterparty creditworthiness and duration of contracts. The assumptions used in these models are critical, since any changes in assumptions could have a significant impact on the fair value of the contracts.

Classification and Recognition Methodology

Substantially all of PacifiCorp's derivative contracts are probable of recovery in rates or are accounted for as cash flow hedges. Therefore, changes in fair value are recorded as a net regulatory asset or liability or accumulated other comprehensive income (loss) ("AOCI"). Accordingly, amounts are generally not recognized in earnings until the contracts are settled. As of December 31, 2008, PacifiCorp had $442 million recorded as a net regulatory asset and $- million recorded as AOCI, before tax, related to these contracts in the Consolidated Balance Sheets. If it becomes no longer probable that a contract will be recovered in rates, the regulatory asset will be written off and recognized in earnings. For contracts in hedge relationships ("hedge contracts"), PacifiCorp discontinues hedge accounting prospectively when it has determined that a derivative no longer qualifies as an effective hedge, or when it is no longer probable that the hedged forecasted transaction will occur. When hedge accounting is discontinued because the derivative no longer qualifies as an effective hedge, future changes in the value of the derivative are charged to earnings. Gains and losses related to discontinued hedges that were previously recorded in AOCI will remain in AOCI until the hedged item is realized, unless it is probable that the hedged forecasted transaction will not occur, at which time associated deferred amounts in AOCI are immediately recognized in earnings.

Pensions and Other Postretirement Benefits

PacifiCorp sponsors defined benefit pension and other postretirement benefit plans that cover the majority of its employees. In addition, certain bargaining unit employees participate in joint trust plans to which PacifiCorp contributes. PacifiCorp recognizes the funded status of its defined benefit pension and other postretirement benefit plans in the Consolidated Balance Sheets. Funded status is the fair value of plan assets minus the benefit obligation as of the measurement date. As of December 31, 2008, PacifiCorp recognized a liability totaling $583 million for the under-funded status of its defined benefit pension and other postretirement benefit plans. As of December 31, 2008, amounts not yet recognized as components of net periodic benefit cost and that were included in regulatory assets totaled $564 million.

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 long-term rate of return on plan assets and health care cost trend rates. These actuarial assumptions are reviewed annually and modified as appropriate. PacifiCorp believes that the assumptions utilized in recording obligations under the Plans are reasonable based on prior experience and market conditions. Through the year ended December 31, 2007, plan assets and benefit obligations were measured as of September 30, three months prior to PacifiCorp's fiscal year end. In 2008, PacifiCorp began measuring its plan assets and benefit obligations as of its fiscal year end, December 31. Refer to Note 11 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for information regarding the change in measurement date and for disclosures about PacifiCorp's pension and other postretirement benefit plans, including the key assumptions used to calculate the funded status and net periodic benefit cost for these plans as of and for the year ended December 31, 2008.

In establishing its assumption as to the expected long-term rate of return on plan assets, PacifiCorp reviews the expected asset allocation and develops return assumptions for each asset class based on historical performance and forward-looking views of the financial markets. Pension and other postretirement benefit expenses increase as the expected long-term rate of return on plan assets decreases. PacifiCorp regularly reviews its actual asset allocations and periodically rebalances its investments to its targeted allocations when considered appropriate.

PacifiCorp chooses a discount rate based upon high quality fixed-income investment yields in effect as of the measurement date that corresponds to the expected benefit period. The pension and other postretirement benefit liabilities, as well as expenses, increase as the discount rate is reduced.

PacifiCorp chooses a health care cost trend rate that reflects the near and long-term expectations of increases in medical costs. The health care cost trend rate gradually declines to 5% by 2012 for participants under 65 and by 2010 for participants over 65, at which point the rate is assumed to remain constant. Refer to Note 11 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for health care cost trend rate sensitivity disclosures.

The actuarial assumptions used may differ materially from period to period due to changing market and economic conditions. These differences may result in a significant impact to the amount of pension and other postretirement benefit expense recorded and the funded status. If changes were to occur for the following assumptions, the approximate effect on the financial statements would be as follows (in millions):

	Pension Plans		**Other Postretirement Benefit Plan**	
	+0.5%	**-0.5%**	**+0.5%**	**-0.5%**
Effect on December 31, 2008 benefit obligations				
Discount rate	$ (51)	$ 55	$ (29)	$ 32
Effect on 2008 periodic cost:				
Discount rate	$ (5)	$ 5	$ (1)	$ 3
Expected rate of return on plan assets	(5)	5	(2)	2

A variety of factors affect the funded status of the Plans, including asset returns, discount rates, plan changes and the plan funding practices of PacifiCorp. Specifically, the Pension Protection Act of 2006 imposed generally more stringent funding requirements for defined benefit pension plans, particularly for those significantly under-funded, and allowed for greater tax deductible contributions to such plans than previous rules permitted under the Employee Retirement Income Security Act of 1974. As a result, PacifiCorp may be required to increase future contributions to its qualified pension plan, and there may be more volatility in annual contributions than historically experienced, which could have a material impact on financial results. Refer to "Sources and Uses of Cash" for additional discussion regarding investment trust valuations.

Refer to Note 11 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for information regarding recent changes to the PacifiCorp Retirement Plan.

Income Taxes

In determining PacifiCorp's income taxes, management is required to interpret complex tax laws and regulations. In preparing tax returns, PacifiCorp is subject to continuous examinations by federal, state and local tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. The IRS has closed its examination of PacifiCorp's income tax returns through the 2000 tax year. In most cases, state jurisdictions have closed their examinations of PacifiCorp's income tax returns through 1993. Although the ultimate resolution of PacifiCorp's federal and state tax examinations is uncertain, PacifiCorp believes it has made adequate provisions for these tax positions and the aggregate amount of any additional tax liabilities that may result from these examinations, if any, will not have a material adverse impact on PacifiCorp's financial results. Assets and liabilities are established for uncertain tax positions taken or positions expected to be taken in income tax returns when such positions are judged to not meet the "more-likely-than-not" threshold based on the technical merits of the position.

PacifiCorp is required to pass income tax benefits related to certain property-related basis differences and other various differences on to its customers in most state jurisdictions. These amounts were recognized as a net regulatory asset totaling $409 million as of December 31, 2008, and will be included in rates when the temporary differences reverse. Management believes the existing regulatory assets are probable of recovery. If it becomes no longer probable that these costs will be recovered, the assets would be written off and recognized in earnings.

PacifiCorp recognizes deferred tax assets and liabilities based on differences between the financial statement and tax bases of assets and liabilities using estimated tax rates in effect for the year in which the differences are expected to reverse.

Revenue Recognition – Unbilled Revenues

Unbilled revenue was $211 million as of December 31, 2008. Revenue is recognized as electricity is delivered or as services are provided. The determination of sales to individual customers is based on the reading of the customer's meter, which is performed on a systematic basis throughout the month. At the end of each month, amounts of energy provided to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recorded. Factors that can impact the estimate of unbilled energy include, but are not limited to, seasonal weather patterns, historical trends, volumes, line losses, economic impacts and composition of customer class. Estimates are generally reversed in the following month and actual revenue is recorded based on subsequent meter readings. Historically, any differences between the actual and estimated amounts have been immaterial.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

PacifiCorp's Consolidated Balance Sheets include assets and liabilities with fair values that are subject to market risks. PacifiCorp's significant market risks are primarily associated with commodity prices and interest rates. PacifiCorp is also exposed to credit risk and has established guidelines for credit risk management. The following sections address the significant market risks associated with PacifiCorp's business activities. The recent unprecedented volatility in the capital and credit markets has developed rapidly and may create additional risks in the future. Refer to Notes 2, 6 and 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding PacifiCorp's accounting for derivative contracts.

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 recommends, and executive management establishes, policies, limits and 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, measure, assess, report and manage 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 and trading activities to take advantage of market inefficiencies. The policy also governs the types of transactions authorized for use and establishes guidelines for credit risk management 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 actively manages 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.

Commodity Price Risk

PacifiCorp is subject to significant commodity price risk. Exposures include variations in the price of fuel costs to generate electricity and the price of wholesale electricity that is purchased and sold. Electricity and natural gas prices are subject to wide price swings as demand responds to, among many other unpredictable items, changing weather, energy supply and demand, generating facility performance and transmission constraints. 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. Forward contracts are used to economically hedge both committed and forecasted energy purchases and sales. Accordingly, the net unrealized gains and losses on those forward contracts that are accounted for as derivatives, and that are probable of recovery in rates, are recorded as net regulatory assets or liabilities. Financial results may be negatively impacted if the costs of fuel and purchased electricity are higher than what is permitted to be recovered in rates.

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. 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 forward market prices and is not necessarily indicative of actual results that may occur.

PacifiCorp's VaR computations utilize several key assumptions. The calculation includes short-term derivative commodity instruments, 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. PacifiCorp's VaR methodology is based on a 48-month forward position, 95% confidence interval and one-day holding period.

As of December 31, 2008, PacifiCorp's estimated potential one-day unfavorable impact on fair value of the electricity and natural gas commodity portfolio over the next 48 months was $12 million, as measured by the VaR computations described above, compared to $14 million as of December 31, 2007. The minimum, average and maximum daily VaR (one-day holding periods) were as follows (in millions):

	Years Ended December 31,		Nine-Month Period Ended
	2008	**2007**	**December 31, 2006**
Minimum VaR (measured)	$ 9	$ 7	$ 7
Average VaR (calculated)	14	12	12
Maximum VaR (measured)	23	20	16

PacifiCorp maintained compliance with its VaR limit procedures during the year ended December 31, 2008. 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 derivative contracts for the year ended December 31, 2008 and quantifies the reasons for the changes (in millions):

	Net Derivative Net Assets (Liabilities)(1)		Net Regulatory Assets
	Trading	Non-trading	(Liabilities)
Fair value of contracts outstanding, January 1, 2008	$ -	$ (256)	$ 256
Contracts realized or otherwise settled during the period	-	(26)	26
Other changes in fair values(2)	3	(81)	160
Fair value of contracts outstanding, December 31, 2008	$ 3	$ (363)	$ 442

(1) Net derivative assets (liabilities) include $82 million of a net asset for cash collateral.

(2) Other changes in fair values include the effects of changes in market prices, inflation rates and interest rates, including those based on models, and on new and existing contracts.

PacifiCorp's valuation models and assumptions are updated daily 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 as of December 31, 2008 (in millions):

	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(1):					
Values based on quoted market prices from third-party sources	$ 2	$ 1	$ -	$ -	$ 3
Non-trading(1):					
Values based on quoted market prices from third-party sources	$ 69	$ 60	$ (43)	$ -	$ 86
Values based on models and other valuation methods	(27)	(48)	(107)	(267)	(449)
Total non-trading	$ 42	$ 12	$ (150)	$ (267)	$ (363)
Net regulatory asset (liability)	$ (21)	$ 46	$ 150	$ 267	$ 442

(1) Net derivative assets (liabilities) include $82 million of a net asset for cash collateral.

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.

The table that follows summarizes PacifiCorp's commodity risk on energy derivative contracts, excluding collateral netting, as of December 31, 2008 and shows the effects of a hypothetical 10% increase and a 10% decrease in forward market prices by the expected volumes for these contracts as of that date. The selected hypothetical change does not reflect what could be considered the best or worst case scenarios (dollars in millions).

	Fair Value – Asset (Liability)	Hypothetical Price Change	Estimated Fair Value after Hypothetical Change in Price
As of December 31, 2008	$ (442)	10% increase	$ (415)
		10% decrease	(469)

Interest Rate Risk

The following table summarizes PacifiCorp's fixed-rate long-term debt totaling $5.0 billion and $4.6 billion as of December 31, 2008 and 2007, respectively, and the hypothetical increases and decreases in interest rates based on rates in effect as of December 31, 2008. Because of their fixed interest rates, these instruments do not expose PacifiCorp to the risk of earnings loss due to changes in market interest rates. In general, such increases and decreases 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. It is assumed that the changes occur immediately and uniformly to each debt instrument. The hypothetical changes in market interest rates do not reflect what could be deemed best or worst case scenarios. For these reasons, actual results might differ from those reflected in the table (dollars in millions).

		Estimated Fair Value after Hypothetical Change in Interest Rates	
	Fair Value	100 bp decrease	100 bp increase
December 31, 2008	$ 5,227	$ 5,780	$ 4,753
December 31, 2007	$ 4,808	$ 5,290	$ 4,400

As of December 31, 2008 and 2007, PacifiCorp had variable-rate long-term debt totaling $542 million. As of December 31, 2008 and 2007, PacifiCorp had variable-rate short-term debt totaling $85 million and $- million, respectively. These variable-rate obligations expose PacifiCorp to the risk of increased interest expense in the event of increases in short-term interest rates. This market risk is not hedged; however, if the variable interest rates were to increase by 10% from December 31 levels, it would not have a material effect on PacifiCorp's consolidated annual interest expense in either year. The carrying amount of variable-rate long-term debt approximates fair value.

Credit Risk

PacifiCorp extends unsecured credit to other utilities, energy marketers, financial institutions and other market participants in conjunction with wholesale energy supply and marketing activities. 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 analyzes the financial condition of each significant wholesale counterparty before entering into any transactions, establishes limits on the amount of unsecured credit to be extended to each counterparty and evaluates the appropriateness of unsecured credit limits on an ongoing basis. To mitigate exposure to the financial risks of wholesale counterparties, PacifiCorp enters into netting and collateral arrangements that may 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.

As of December 31, 2008, 69% of PacifiCorp's credit exposure from wholesale activities, net of collateral, was with counterparties having investment grade credit ratings by either Moody's or Standard & Poor's. An additional 4% of PacifiCorp's credit exposure from wholesale activities, net of collateral, was from counterparties having financial characteristics deemed equivalent to investment grade based on internal review.

As of December 31, 2008, less than 1% of PacifiCorp's credit exposure, net of collateral, from wholesale activities was with counterparties having externally rated "non-investment grade" credit ratings, while an additional 26% of PacifiCorp's credit exposure, net of collateral, from wholesale activities was with counterparties having financial characteristics deemed equivalent to "non-investment grade" by PacifiCorp based on internal review.

Two counterparties comprise 35% of PacifiCorp's aggregate credit exposure from wholesale activities, net of collateral, as of December 31, 2008. One counterparty is rated investment grade by Moody's and Standard & Poor's and PacifiCorp is not aware of any factors that would likely result in a downgrade of the counterparty's credit ratings to below investment grade over the remaining term of transactions outstanding as of December 31, 2008. The other counterparty has a non-investment grade credit rating based on internal review as of December 31, 2008.

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
PacifiCorp
Portland, Oregon

We have audited the accompanying consolidated balance sheets of PacifiCorp and its subsidiaries (the "Company") as of December 31, 2008 and 2007, and the related consolidated statements of operations, cash flows and of changes in common shareholder's equity and comprehensive income for the years ended December 31, 2008 and 2007 and the nine-month period ended December 31, 2006. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with 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 PacifiCorp and its subsidiaries as of December 31, 2008 and 2007, and the results of their operations and their cash flows for the years ended December 31, 2008 and 2007 and the nine-month period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America.

/s/Deloitte & Touche LLP

Portland, Oregon
February 27, 2009

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2008	2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 59	$ 228
Accounts receivable, net	609	594
Income taxes receivable from affiliates	43	23
Inventories:		
Materials and supplies	184	163
Fuel	155	129
Derivative contracts	174	143
Deferred income taxes	74	55
Other current assets	78	141
Total current assets	1,376	1,476
Property, plant and equipment, net	13,824	11,849
Regulatory assets	1,624	1,091
Derivative contracts	86	215
Deferred charges, investments and other	257	276
Total assets	$ 17,167	$ 14,907

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

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (continued)
(Amounts in millions)

	As of December 31,	
	2008	**2007**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 757	$ 451
Accrued employee expenses	77	80
Accrued interest	89	74
Accrued taxes	73	28
Derivative contracts	130	117
Short-term debt	85	-
Current portion of long-term debt and capital lease obligations	144	414
Other current liabilities	111	149
Total current liabilities	1,466	1,313
Regulatory liabilities	821	799
Derivative contracts	490	497
Long-term debt and capital lease obligations	5,424	4,753
Deferred income taxes	2,025	1,701
Other long-term liabilities	954	764
Total liabilities	11,180	9,827
Commitments and contingencies (Note 13)		
Shareholders' equity:		
Preferred stock	41	41
Common equity:		
Common stock – 750 shares authorized, no par value, 357 shares issued and outstanding	-	-
Additional paid-in capital	4,254	3,804
Retained earnings	1,694	1,239
Accumulated other comprehensive loss, net	(2)	(4)
Total common equity	5,946	5,039
Total shareholders' equity	5,987	5,080
Total liabilities and shareholders' equity	$ 17,167	$ 14,907

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

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31, 2008	Years Ended December 31, 2007	Nine-Month Period Ended December 31, 2006
Operating revenue	$ 4,498	$ 4,258	$ 2,924
Operating costs and expenses:			
Energy costs	1,957	1,768	1,297
Operations and maintenance	992	1,004	780
Depreciation and amortization	490	497	355
Taxes, other than income taxes	112	101	77
Total operating costs and expenses	3,551	3,370	2,509
Operating income	947	888	415
Other income (expense):			
Interest expense	(343)	(314)	(215)
Allowance for borrowed funds	34	29	18
Allowance for equity funds	47	41	17
Interest income	11	15	6
Other, net	-	-	6
Total other income (expense)	(251)	(229)	(168)
Income before income tax expense	696	659	247
Income tax expense	238	220	86
Net income	$ 458	$ 439	$ 161

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

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31, 2008	Years Ended December 31, 2007	Nine-Month Period Ended December 31, 2006
Cash flows from operating activities:			
Net income	$ 458	$ 439	$ 161
Adjustments to reconcile net income to net cash flows from operating activities:			
Unrealized loss (gain) on derivative contracts, net	-	(1)	104
Depreciation and amortization	490	497	355
Regulatory asset/liability establishment and amortization	(37)	(45)	5
Provision for deferred income taxes	308	39	6
Other	(3)	10	14
Changes in operating assets and liabilities, net of effects from acquisition:			
Accounts receivable, net and other assets	3	(81)	(129)
Derivative contract assets/liabilities, net	(82)	-	(4)
Inventories	(52)	(48)	(32)
Income taxes receivable/payable from/to affiliates, net	(20)	21	(48)
Accounts payable and other liabilities	(73)	(7)	(1)
Net cash flows from operating activities	992	824	431
Cash flows from investing activities:			
Capital expenditures	(1,789)	(1,519)	(1,051)
Acquisition, net of cash acquired	(308)	-	-
Purchases of available-for-sale securities	(52)	(25)	(82)
Proceeds from sales of available-for-sale securities	67	30	68
Other	6	17	9
Net cash flows from investing activities	(2,076)	(1,497)	(1,056)
Cash flows from financing activities:			
Net borrowings (repayments) of commercial paper	85	(397)	213
Proceeds from long-term debt, net	797	1,193	348
Proceeds from previously purchased long-term debt	216	-	-
Proceeds from equity contributions	450	200	215
Preferred stock dividends paid	(2)	(2)	(2)
Purchases of long-term debt	(216)	-	-
Repayments and redemptions of long-term debt and capital lease obligations	(413)	(127)	(211)
Redemptions of preferred stock subject to mandatory redemption	-	(38)	(8)
Other	(2)	13	9
Net cash flows from financing activities	915	842	564
Net change in cash and cash equivalents	(169)	169	(61)
Cash and cash equivalents at beginning of period	228	59	120
Cash and cash equivalents at end of period	$ 59	$ 228	$ 59

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

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME
(Amounts in millions)

	Common Shares	Common Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss, Net	Total Comprehensive Income
Balance at March 31, 2006	357	$ -	$ 3,382	$ 630	$ (2)	
Net income	-	-	-	161	-	$ 161
Other comprehensive income (loss):						
Fair value adjustment on cash flow hedges, net of tax of $1	-	-	-	-	2	2
Unrealized loss on available-for-sale securities, net of tax of $(2)	-	-	-	-	(3)	(3)
Adoption of SFAS No. 158 recognition provisions, net of tax of $(1)	-	-	-	-	(1)	-
Equity contributions	-	-	215	-	-	-
Tax benefit from stock option exercises	-	-	3	-	-	-
Preferred stock dividends declared	-	-	-	(2)	-	-
Balance at December 31, 2006	357	-	3,600	789	(4)	$ 160
Net income	-	-	-	439	-	$ 439
Other comprehensive income (loss):						
Fair value adjustment on cash flow hedges, net of tax of $(1)	-	-	-	-	(2)	(2)
Unrecognized amounts on retirement benefits, net of tax of $2	-	-	-	-	2	2
Adoption of FASB Interpretation No. 48	-	-	-	13	-	-
Equity contributions	-	-	200	-	-	-
Tax benefit from stock option exercises	-	-	4	-	-	-
Preferred stock dividends declared	-	-	-	(2)	-	-
Balance at December 31, 2007	357	-	3,804	1,239	(4)	$ 439
Net income	-	-	-	458	-	$ 458
Other comprehensive income:						
Unrecognized amounts on retirement benefits, net of tax of $-	-	-	-	-	2	2
Adoption of SFAS No. 158 measurement date provisions, net of tax of $(1)				(1)	-	-
Equity contributions	-	-	450	-	-	-
Preferred stock dividends declared	-	-	-	(2)	-	-
Balance at December 31, 2008	357	$ -	$ 4,254	$ 1,694	$ (2)	$ 460

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

PACIFICORP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and Operations

PacifiCorp, which includes PacifiCorp and its subsidiaries, is a United States regulated electric company serving 1.7 million retail customers, including residential, commercial, industrial and other customers in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp owns, or has interests in, a number of thermal, hydroelectric, wind-powered and geothermal generating facilities, as well as electric transmission and distribution assets. PacifiCorp also buys and sells electricity on the wholesale market with public and private utilities, energy marketing companies and incorporated municipalities. PacifiCorp is subject to comprehensive state and federal regulation. PacifiCorp's subsidiaries support its electric utility operations by providing coal-mining facilities and services and environmental remediation services. PacifiCorp is an indirect subsidiary of MidAmerican Energy Holdings Company ("MEHC"), a holding company based in Des Moines, Iowa, owning subsidiaries that are principally engaged in energy businesses. MEHC is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

In May 2006, the PacifiCorp Board of Directors elected to change PacifiCorp's fiscal year-end from March 31 to December 31. As a result, the Consolidated Statements of Operations include the audited nine-month transition period ended December 31, 2006.

(2) Summary of Significant Accounting Policies

Basis of Consolidation

The Consolidated Financial Statements include the accounts of PacifiCorp and its subsidiaries in which it holds a controlling financial interest as of the financial statement date. The Consolidated Statements of Operations include the revenues and expenses of an acquired entity from the date of acquisition. Intercompany accounts and transactions have been eliminated. Certain amounts in the prior year Consolidated Financial Statements have been reclassified to conform to the current year presentation. Such reclassifications did not impact previously reported operating income, net income or retained earnings.

Minority interest in Bridger Coal Company, a consolidated subsidiary, was $80 million and $79 million as of December 31, 2008 and 2007, respectively, and is included in other long-term liabilities in the Consolidated Balance Sheets.

In April 2007, PacifiCorp acquired the outstanding 10% minority interest in PacifiCorp Environmental Remediation Company ("PERCo") for $150,000 and PERCo became a wholly owned subsidiary of PacifiCorp.

In August 2007, PacifiCorp's steam delivery subsidiary, Intermountain Geothermal Company, was merged into PacifiCorp. PacifiCorp has 95% of the steam rights associated with the geothermal field serving PacifiCorp's Blundell geothermal plant.

Use of Estimates in Preparation of Financial Statements

The preparation of the Consolidated Financial Statements in conformity with accounting principles generally accepted in the United States of America ("GAAP") 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 period. These estimates include, but are not limited to: unbilled revenue; valuation of energy contracts; effects of regulation; asset retirement obligations ("AROs"), accounting for contingencies, including environmental, regulatory and income tax matters; and certain assumptions made in accounting for pension and other postretirement benefits. Actual results may differ from the estimates used in preparing the Consolidated Financial Statements.

Cash Equivalents and Restricted Cash

Cash equivalents consist of funds invested in money market accounts and in other investments with a maturity of three months or less when purchased. Cash and cash equivalents exclude amounts where availability is restricted by legal requirements, loan agreements or other contractual provisions. Restricted amounts are included in other current assets and deferred charges, investments and other in the Consolidated Balance Sheets.

Marketable Securities

PacifiCorp's investments in debt and equity securities are classified as available-for-sale. PacifiCorp's management determines the appropriate classifications of investments in debt and equity securities at the acquisition date and re-evaluates the classifications at each balance sheet date.

Available-for-sale securities are carried at fair value with realized gains and losses, as determined on a specific identification basis, recognized in earnings and unrealized gains and losses recognized in accumulated other comprehensive income ("AOCI"), net of tax. Realized and unrealized gains and losses on the trust fund related to the final reclamation of leased coal-mining property are recorded as net regulatory assets or liabilities since PacifiCorp expects to recover costs for these activities through rates. If in management's judgment a decline in the value of an investment below cost is other than temporary, the cost is written down to fair value. For the reclamation trust, any other-than-temporary decline of an investment below cost would not impact PacifiCorp's financial results due to the regulatory treatment of gains and losses. Factors considered in judging whether an impairment is other than temporary include: the financial condition, business prospects and creditworthiness of the issuer; the length of time that fair value has been less than cost; the relative amount of the decline and PacifiCorp's ability and intent to hold the investment until the fair value recovers.

Accounting for the Effects of Certain Types of Regulation

PacifiCorp prepares its financial statements in accordance with the provisions of Statement of Financial Accounting Standards ("SFAS") No. 71, *Accounting for the Effects of Certain Types of Regulation* ("SFAS No. 71"), which differs in certain respects from the application of GAAP by non-regulated businesses. In general, SFAS No. 71 recognizes that accounting for rate-regulated enterprises should reflect the economic effects of regulation. As a result, a regulated entity is required to defer the recognition of costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future rates. Accordingly, PacifiCorp has deferred certain costs and income that will be recognized in earnings over various future periods.

Management continually evaluates the applicability of SFAS No. 71 and assesses whether its regulatory assets are probable of future recovery by considering factors such as a change in the regulator's approach to setting rates from cost-based ratemaking to another form of regulation; other regulatory actions; or the impact of competition, which could limit PacifiCorp's ability to recover its costs. Based upon this continual assessment, management believes the application of SFAS No. 71 continues to be appropriate and its existing regulatory assets are probable of recovery. The assessment reflects the current political and regulatory climate at both the state and federal levels and is subject to change in the future. If it becomes no longer probable that these costs will be recovered, the regulatory assets and regulatory liabilities would be written off and recognized in earnings.

Allowance for Doubtful Accounts

The allowance for doubtful accounts is based on PacifiCorp's assessment of the collectibility of payments from its customers. This assessment requires judgment regarding the ability of customers to pay the amounts owed to PacifiCorp or the outcome of any pending disputes. The change in the balance of the allowance for doubtful accounts, which is included in accounts receivable, net in the Consolidated Balance Sheets is summarized as follows (in millions):

	Years Ended December 31,		Nine-Month Period Ended
	2008	**2007**	**December 31, 2006**
Beginning balance	$ 7	$ 12	$ 11
Charged to operating costs and expenses, net	14	9	8
Write-offs, net	(12)	(14)	(7)
Ending balance	$ 9	$ 7	$ 12

Derivatives

PacifiCorp employs a number of different commodity derivative instruments, including forward contracts, options, swaps and other agreements, to manage its commodity price, for example natural gas and electricity volatility. Derivative instruments are recorded in the Consolidated Balance Sheets as either assets or liabilities and are stated at fair value unless they are designated as normal purchases or normal sales and qualify for the exemption afforded by GAAP. Derivative balances reflect reductions permitted under master netting arrangements with counterparties and cash collateral paid or received under such agreements. For those derivative contracts that are probable of recovery in rates, the unrealized gains and losses are recorded as a net regulatory asset or liability pursuant to SFAS No. 71.

Derivative contracts for commodities used in normal business operations that are settled by physical delivery, among other criteria, are eligible for and may be designated as normal purchases or normal sales pursuant to the exemption. Contracts that qualify and are designated as normal purchases or normal sales are not marked to market. Recognition of these contracts in operating revenue or energy costs in the Consolidated Statements of Operations occurs when the contracts settle.

For contracts designated in hedge relationships ("hedge contracts"), PacifiCorp formally assesses, at inception and thereafter, whether the hedge contracts are highly effective in offsetting changes in cash flows or fair values of the hedged items. PacifiCorp formally documents hedging activity by transaction type and risk management strategy.

Changes in the fair value of a derivative designated and qualified as a cash flow hedge, to the extent effective, are included in the Consolidated Statements of Changes in Common Shareholder's Equity and Comprehensive Income as AOCI, net of tax, until the hedged item is recognized in earnings. PacifiCorp discontinues hedge accounting prospectively when it has determined that a derivative no longer qualifies as an effective hedge, or when it is no longer probable that the hedged forecasted transaction will occur. When hedge accounting is discontinued because the derivative no longer qualifies as an effective hedge, future changes in the value of the derivative are charged to earnings. Gains and losses related to discontinued hedges that were previously recorded in AOCI will remain in AOCI until the hedged item is realized, unless it is probable that the hedged forecasted transaction will not occur, at which time associated deferred amounts in AOCI are immediately recognized in earnings.

Inventories

Inventories consist mainly of materials and supplies, coal stocks, natural gas and fuel oil, which are stated at the lower of average cost or market.

Property, Plant and Equipment, Net

General

Property, plant and equipment is recorded at historical cost. PacifiCorp capitalizes all construction-related material, direct labor and contract services, as well as indirect construction costs, which include allowance for funds used during construction ("AFUDC"). The cost of major additions and betterments are capitalized, while costs for replacements, maintenance and repairs that do not improve or extend the lives of the respective assets are charged to operating expense.

Generally when PacifiCorp retires or sells its regulated property, plant and equipment, it charges the original cost to accumulated depreciation. Any cost of removal is charged against the cost of removal regulatory liability that was established through depreciation rates. Salvage is considered in determining future depreciation rates and is recorded in the accumulated depreciation and amortization accounts.

PacifiCorp records AFUDC, which represents the estimated costs of debt and equity funds necessary to finance additions to property, plant and equipment. AFUDC is capitalized as a component of property, plant and equipment, with offsetting credits to the Consolidated Statements of Operations. After construction is completed, PacifiCorp is permitted to earn a return on these costs by their inclusion in rate base, as well as recover these costs through depreciation expense over the useful life of the related assets.

The weighted-average aggregate rates used for AFUDC were 8.2% and 8.3% for the years ended December 31, 2008 and 2007, respectively, and 7.5% for the nine-month period ended December 31, 2006.

Asset Retirement Obligations

The fair value of an ARO liability is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made, and is added to the carrying amount of the associated asset, which is then depreciated over the remaining useful life of the asset. Subsequent to the initial recognition, the ARO 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 ARO liability due to the passage of time. The difference between the ARO liability, the corresponding ARO asset included in property, plant and equipment and amounts recovered in rates to satisfy such liabilities is recorded as a regulatory asset or liability. Estimated removal costs that PacifiCorp recovers through approved depreciation rates, but that do not meet the requirements of a legal ARO, are accumulated in asset retirement removal costs within regulatory liabilities in the Consolidated Balance Sheets.

Depreciation and Amortization

Depreciation and amortization are computed by the straight-line group method either over the life prescribed by PacifiCorp's various regulatory jurisdictions or over the assets' estimated useful lives. Periodic depreciation studies are performed to determine the appropriate group lives, salvage and group depreciation rates. These studies are reviewed and approved by PacifiCorp's various regulatory bodies.

Revenue Recognition

Revenue is recognized as electricity is delivered and includes amounts for services rendered. Revenue recognized includes unbilled, as well as billed, amounts. Unbilled revenues included in accounts receivable, net in the Consolidated Balance Sheets were $211 million and $192 million as of December 31, 2008 and 2007, respectively. Rates charged are subject to federal and state regulation.

The determination of sales to individual customers is based on the reading of the customer's meter, which is performed on a systematic basis throughout the month. At the end of each month, amounts of energy provided to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recorded. The estimate is reversed in the following month and actual revenue is recorded based on subsequent meter readings.

The monthly unbilled revenues of PacifiCorp are determined by the estimation of unbilled energy provided during the period, the assignment of unbilled energy provided to customer classes and the average rate per customer class. Factors that can impact the estimate of unbilled energy provided include, but are not limited to, seasonal weather patterns, customer usage patterns, historical trends, volumes, line losses, retail rate changes and composition of customer classes.

PacifiCorp records sales, franchise and excise taxes, which are collected directly from customers and remitted directly to the taxing authorities, on a net basis in the Consolidated Statements of Operations.

Income Taxes

As a result of the sale of PacifiCorp to MEHC on March 21, 2006, Berkshire Hathaway commenced including PacifiCorp in its United States federal income tax return. PacifiCorp's provision for income taxes has been computed on the basis that it files separate consolidated income tax returns. Prior to the sale, PacifiCorp was included in the consolidated United States federal income tax return of PacifiCorp Holdings, Inc., PacifiCorp's former parent company.

Deferred tax assets and liabilities are based on differences between the financial statements and tax bases of assets and liabilities using the estimated tax rates in effect for the year in which the differences are expected to reverse. Changes in deferred income tax assets and liabilities that are associated with components of AOCI are charged or credited directly to AOCI. Changes in deferred income tax assets and liabilities that are associated with income tax benefits related to certain property-related basis differences and other various differences that PacifiCorp is required to pass on to its customers in most state jurisdictions are charged or credited directly to a regulatory asset or regulatory liability. These amounts were recognized as a net regulatory asset of $409 million and $423 million as of December 31, 2008 and 2007, respectively, and will be included in rates when the temporary differences reverse. Other changes in deferred income tax assets and liabilities are included as a component of income tax expense.

Investment tax credits are generally deferred and amortized over the estimated useful lives of the related properties or as prescribed by various regulatory jurisdictions. Investment tax credits included in other long-term liabilities in the Consolidated Balance Sheets were $50 million and $54 million as of December 31, 2008 and 2007, respectively.

In determining PacifiCorp's income taxes, management is required to interpret complex tax laws and regulations. In preparing tax returns, PacifiCorp is subject to continuous examinations by federal, state and local tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. The United States Internal Revenue Service has closed its examination of PacifiCorp's income tax returns through the 2000 tax year. In most cases, state jurisdictions have closed their examinations of PacifiCorp's income tax returns through 1993. Although the ultimate resolution of PacifiCorp's federal and state tax examinations is uncertain, PacifiCorp believes it has made adequate provisions for these tax positions and the aggregate amount of any additional tax liabilities that may result from these examinations, if any, will not have a material adverse effect on PacifiCorp's financial results. Assets and liabilities are established for uncertain tax positions taken or positions expected to be taken in income tax returns when such positions are judged to not meet the "more-likely-than-not" threshold based on the technical merits of the position. PacifiCorp's unrecognized tax benefits are primarily included in accrued taxes and other long-term liabilities in the Consolidated Balance Sheets. PacifiCorp recognizes interest and penalties related to income taxes in income tax expense in the Consolidated Statements of Operations.

Segment Information

PacifiCorp currently has one segment, which includes the regulated retail and wholesale electric utility operations.

New Accounting Pronouncements

In December 2008, the Financial Accounting Standards Board (the "FASB") issued FASB Staff Position ("FSP") No. 132(R)-1, *Employers' Disclosures about Postretirement Benefit Plan Assets* ("FSP FAS 132(R)-1"). FSP FAS 132(R)-1 is intended to improve financial reporting about plan assets of defined benefit pension and other postretirement plans by requiring enhanced disclosures to enable investors to better understand how investment allocation decisions are made and the major categories of plan assets. FSP FAS 132(R)-1 also requires disclosure of the inputs and valuation techniques used to measure fair value and the effect of fair value measurements using significant unobservable inputs on changes in plan assets. In addition, FSP FAS 132(R)-1 establishes disclosure requirements for significant concentrations of risk within plan assets. FSP FAS 132(R)-1 is effective for financial statements issued for fiscal years beginning after December 15, 2009, with early application permitted. PacifiCorp is currently evaluating the impact of adopting FSP FAS 132(R)-1 on its disclosures included within Notes to Consolidated Financial Statements.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities—an amendment of FASB Statement No. 133* ("SFAS No. 161"). SFAS No. 161 is intended to improve financial reporting about derivative instruments and hedging activities by requiring enhanced disclosures to enable investors to better understand how and why an entity uses derivative instruments and their effects on an entity's financial position, financial performance and cash flows. SFAS No. 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008 with early application encouraged. PacifiCorp is currently evaluating the impact of adopting SFAS No. 161 on its disclosures included within Notes to Consolidated Financial Statements.

In December 2007, the FASB issued SFAS No. 141(R), *Business Combinations* ("SFAS No. 141(R)"). SFAS No. 141(R) applies to all transactions or other events in which an entity obtains control of one or more businesses. SFAS No. 141(R) establishes how the acquirer of a business should recognize, measure and disclose in its financial statements the identifiable assets and goodwill acquired, the liabilities assumed and any noncontrolling interest in the acquired business. SFAS No. 141(R) is applied prospectively for all business combinations with an acquisition date on or after the beginning of the first annual reporting period beginning on or after December 15, 2008, with early application prohibited. SFAS No. 141(R) will not have an impact on PacifiCorp's historical Consolidated Financial Statements and will be applied to business combinations completed, if any, on or after January 1, 2009.

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements—an amendment of ARB No. 51* ("SFAS No. 160"). SFAS No. 160 establishes accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. SFAS No. 160 requires entities to report noncontrolling interests as a separate component of shareholders' equity in the consolidated financial statements. The amount of earnings attributable to the parent and to the noncontrolling interests should be clearly identified and presented on the face of the consolidated statements of operations. Additionally, SFAS No. 160 requires any changes in a parent's ownership interest of its subsidiary, while retaining its control, to be accounted for as equity transactions. SFAS No. 160 is effective for fiscal years beginning on or after December 15, 2008 and interim periods within those fiscal years. PacifiCorp is currently evaluating the impact of adopting SFAS No. 160 on its consolidated financial position and results of operations.

In September 2006, FASB issued SFAS No. 157, *Fair Value Measurements* ("SFAS No. 157"). SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. SFAS No. 157 does not impose fair value measurements on items not already accounted for at fair value; rather, it applies, with certain exceptions, to other accounting pronouncements that either require or permit fair value measurements. Under SFAS No. 157, fair value refers to the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants in the principal or most advantageous market. The standard clarifies that fair value should be based on the assumptions market participants would use when pricing the asset or liability. In February 2008, the FASB issued FSP No. 157-2, *Effective Date of FASB Statement No. 157*, which delays the effective date of SFAS No. 157 for all non-financial assets and liabilities, except those that are recognized or disclosed at fair value in the consolidated financial statements on a recurring basis, until fiscal years beginning after November 15, 2008. These non-financial items include assets and liabilities such as non-financial assets and liabilities assumed in a business combination, reporting units measured at fair value in a goodwill impairment test and AROs initially measured at fair value. In October 2008, the FASB issued FSP No. 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active* ("FSP FAS 157-3"), which clarifies the application of SFAS No. 157 in a market that is not active and provides an example to illustrate key considerations in determining the fair value of a financial asset when the market for that financial asset is not active. FSP FAS 157-3 was effective upon issuance, including prior periods for which financial statements had not been issued. PacifiCorp adopted the provisions of SFAS No. 157 for assets and liabilities recognized at fair value on a recurring basis effective January 1, 2008. The partial adoption of SFAS No. 157 did not have a material impact on PacifiCorp's Consolidated Financial Statements.

In September 2006, the FASB issued SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans—an amendment of FASB Statements No. 87, 88, 106, and 132(R)* ("SFAS No. 158"). PacifiCorp adopted the recognition provisions of SFAS No. 158 at December 31, 2006. SFAS No. 158 also requires that an employer measure plan assets and obligations as of the end of the employer's fiscal year, eliminating the option in SFAS No. 87 and SFAS No. 106 to measure up to three months prior to the financial statement date. PacifiCorp adopted the requirement to measure plan assets and benefit obligations as of the date of its fiscal year-end at December 31, 2008. Upon adoption of the measurement date provisions, PacifiCorp recorded a transitional adjustment of $14 million, $12 million of which is considered probable of recovery in rates and was recorded as a regulatory asset. The remaining $2 million (pre-tax) is not considered probable of recovery in rates and was recorded as a reduction in retained earnings.

(3) Property, Plant and Equipment, Net

Property, plant and equipment, net consists of the following as of December 31 (in millions):

	Depreciation Life	2008	2007
Property, plant and equipment:			
Generation	15 – 80 years	$ 8,155	$ 6,814
Transmission	25 – 75 years	3,057	2,878
Distribution	44 – 52 years	5,109	4,885
Intangible plant[(1)]	5 – 50 years	721	671
Other	5 – 29 years	1,837	1,766
Property, plant and equipment in service		18,879	17,014
Accumulated depreciation and amortization		(6,275)	(6,125)
Net property, plant and equipment in service		12,604	10,889
Construction work-in-progress		1,220	960
Total property, plant and equipment, net		$ 13,824	$ 11,849

(1) Computer software costs included in intangible plant are initially assigned a depreciable life of 5 to 10 years.

Utility Plant Acquisition

On September 15, 2008, after having received the required regulatory approvals, PacifiCorp acquired from TNA Merchant Projects, Inc., an affiliate of Suez Energy North America, Inc., 100% of the equity interests of Chehalis Power Generating, LLC, an entity owning a 520-megawatt ("MW") natural gas-fired generating plant located in Chehalis, Washington. The total cash purchase price was $308 million and the estimated fair value of the acquired entity was primarily allocated to the plant. Chehalis Power Generating, LLC was merged into PacifiCorp immediately following the acquisition. The results of the plant's operations have been included in PacifiCorp's Consolidated Financial Statements since the acquisition date.

Unallocated Acquisition Adjustments

PacifiCorp has unallocated acquisition adjustments that represent the excess of costs of the acquired interests in property, plant and equipment purchased from the entity that first devoted the assets to utility service over their net book value in those assets. These unallocated acquisition adjustments included in other property, plant and equipment had an original cost of $157 million as of December 31, 2008 and 2007 and accumulated depreciation of $91 million and $85 million as of December 31, 2008 and 2007, respectively.

Depreciation Study

In August 2007, PacifiCorp filed applications with the regulatory commissions in Utah, Oregon, Wyoming, Washington and Idaho to change its rates of depreciation prospectively based on a new depreciation study. PacifiCorp received approval to change the depreciation rates effective January 1, 2008. The Oregon Public Utility Commission (the "OPUC") order required additional modifications related to the depreciation lives of coal-fired generating facilities, which were approved in August 2008. The revised depreciation rates generally reflect an extension of the lives of PacifiCorp's assets. The most significant change resulted in an increase in the range of depreciable lives for steam plant from 20 – 43 years to 20 – 57 years. The revised depreciation rates resulted in a benefit to pre-tax income during the year ended December 31, 2008 of approximately $47 million.

(4) Jointly Owned Utility Facilities

Under joint facility ownership agreements with other utilities, PacifiCorp, as a tenant in common, has undivided interests in jointly owned generation and transmission facilities. PacifiCorp accounts for its proportional share of each facility, and each joint owner has provided financing for its share of each generating facility or transmission line. Operating costs of each facility are assigned to joint owners based on ownership percentage or energy purchased, depending on the nature of the cost. Operating costs and expenses in the Consolidated Statements of Operations include PacifiCorp's share of the expenses of these facilities.

The amounts shown in the table below represent PacifiCorp's share in each jointly owned facility as of December 31, 2008 (dollars in millions):

	PacifiCorp Share	Facility in Service	Accumulated Depreciation/ Amortization	Construction Work-in-Progress
Jim Bridger Nos. 1 – 4 [(1)]	67%	$ 996	$ 481	$ 29
Wyodak [(1)]	80	333	172	4
Hunter No. 1	94	305	150	8
Colstrip Nos. 3 and 4 [(1)]	10	244	121	2
Hunter No. 2	60	194	90	10
Hermiston [(2)]	50	173	41	-
Craig Nos. 1 and 2	19	168	79	-
Hayden No. 1	25	45	21	1
Foote Creek	79	37	15	-
Hayden No. 2	13	28	14	1
Other transmission and distribution facilities	Various	83	19	-
Total		$ 2,606	$ 1,203	$ 55

(1) Includes transmission lines and substations.

(2) PacifiCorp has contracted to purchase the remaining 50% of the output of the Hermiston plant.

(5) Regulatory Matters

Regulatory Assets and Liabilities

Regulatory assets represent costs that are expected to be recovered in future rates. PacifiCorp's regulatory assets reflected in the Consolidated Balance Sheets consist of the following as of December 31 (in millions):

	Weighted Average Remaining Life	2008	2007
Employee benefit plans [1]	10 years	$ 564	$ 227
Net unrealized loss on derivative contracts [2]	7 years	442	256
Deferred income taxes [3]	33 years	440	459
Other	Various	178	149
Total		$ 1,624	$ 1,091

(1) Represents amounts not yet recognized as components of net periodic benefit cost that will be recovered in rates when recognized. The 2008 amount is partially offset by $26 million of net regulatory deferrals related to the curtailment gains and measurement date change transitional adjustment.

(2) Amounts represent net unrealized losses related to derivative contracts included in rates.

(3) Amounts represent income tax benefits related to certain property-related basis differences and other various differences that were previously flowed through to customers and will be included in rates when the temporary differences reverse.

PacifiCorp had regulatory assets not earning a return on investment of $1.5 billion and $945 million as of December 31, 2008 and 2007, respectively.

Regulatory liabilities represent income to be recognized or amounts to be returned to customers in future periods. PacifiCorp's regulatory liabilities reflected in the Consolidated Balance Sheets consist of the following as of December 31 (in millions):

	Weighted Average Remaining Life	2008	2007
Cost of removal [1]	33 years	$ 732	$ 707
Deferred income taxes	Various	31	36
Other	Various	58	56
Total		$ 821	$ 799

(1) Amounts represent the remaining estimated costs, as accrued through depreciation rates and exclusive of ARO liabilities, of removing electric utility assets in accordance with accepted regulatory practices.

Rate Matters

Oregon

In October 2007, PacifiCorp filed its tax report for 2006 under Oregon Senate Bill 408 ("SB 408"), which was enacted in September 2005. SB 408 requires that PacifiCorp and other large regulated, investor-owned utilities that provide electric or natural gas service to Oregon customers file a report annually with the OPUC comparing income taxes collected and income taxes paid, as defined by the statute and its administrative rules. PacifiCorp's filing indicated that for the 2006 tax year, PacifiCorp paid $33 million more in federal, state and local taxes than was collected in rates from its retail customers. PacifiCorp proposed to recover $27 million of the deficiency over a one-year period starting June 1, 2008 and to defer any excess into a balancing account for future disposition. During the review process, PacifiCorp updated its filing to address the OPUC's staff recommendations, which increased the initial request by $2 million for a total of $35 million. In April 2008, the OPUC approved PacifiCorp's revised request with $27 million to be recovered over a one-year period beginning June 1, 2008 and the remainder to be deferred until a later period, with interest to accrue at PacifiCorp's authorized rate of return. In June 2008, PacifiCorp recorded a $27 million regulatory asset and associated revenues representing the amount that PacifiCorp will collect from its Oregon retail customers over the one-year period that began on June 1, 2008.

In May 2008, the Industrial Customers of Northwest Utilities ("ICNU") filed a petition with the Court of Appeals of the State of Oregon seeking judicial review of the final order with regards to PacifiCorp's 2006 SB 408 tax report. In December 2008, ICNU filed their opening brief. PacifiCorp and the OPUC have until March 27, 2009 to file their response briefs. PacifiCorp believes the outcome of the judicial review will not have a material impact on its consolidated financial results.

In October 2008, PacifiCorp filed its tax report for 2007 under SB 408. PacifiCorp's filing indicated that for the 2007 tax year, PacifiCorp paid $4 million more in federal, state and local taxes than was collected in rates from its retail customers.

(6) Fair Value Measurements

The carrying amounts of PacifiCorp's cash and cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximate fair value because of the short-term maturity of these instruments. PacifiCorp has various financial instruments that are measured at fair value in the Consolidated Financial Statements, including marketable debt and equity securities and commodity derivatives. PacifiCorp's financial assets and liabilities are measured using inputs from the three levels of the fair value hierarchy. A financial asset or liability classification within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement. The three levels are as follows:

- Level 1 – Inputs are unadjusted quoted prices in active markets for identical assets or liabilities that PacifiCorp has the ability to access at the measurement date.
- Level 2 – Inputs include quoted prices for similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means (market corroborated inputs).
- Level 3 – Unobservable inputs reflect PacifiCorp's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. PacifiCorp develops these inputs based on the best information available, including PacifiCorp's own data.

The following table presents PacifiCorp's assets and liabilities recognized in the Consolidated Balance Sheet and measured at fair value on a recurring basis as of December 31, 2008 (in millions):

	Input Levels for Fair Value Measurements				
Description	**Level 1**	**Level 2**	**Level 3**	**Other(1)**	**Total**
Assets(2):					
Investments in available-for-sale securities	$ 30	$ 48	$ -	$ -	$ 78
Commodity derivatives	-	474	88	(302)	260
	$ 30	$ 522	$ 88	$ (302)	$ 338
Liabilities:					
Commodity derivatives	$ -	$ (485)	$ (496)	$ 361	$ (620)

(1) Primarily represents netting under master netting arrangements and cash collateral requirements.

(2) Does not include investments in either pension or other postretirement benefit plan assets.

PacifiCorp's investments in debt and equity securities are classified as available-for-sale and stated at fair value. When available, the quoted market price or net asset value of an identical security in the principal market is used to record the fair value. In the absence of a quoted market price in a readily observable market, the fair value is determined using pricing models based on observable market inputs and quoted market prices of securities with similar characteristics. Substantially all of PacifiCorp's available-for-sale securities in Level 1 and 2 above are held in the Bridger Coal Company reclamation trust.

PacifiCorp uses various derivative instruments, including forward contracts, options, swaps and other agreements. The fair value of derivative instruments is determined using unadjusted quoted prices for identical instruments on the applicable exchange in which PacifiCorp transacts. When quoted prices for identical instruments are not available, PacifiCorp uses forward price curves derived from market price quotations, when available, or internally developed and commercial models, with internal and external fundamental data inputs. Market price quotations are obtained from independent energy brokers, exchanges, direct communication with market participants and actual transactions executed by PacifiCorp. Market price quotations for certain major electricity and natural gas 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. Market price quotations for other electricity and natural gas trading hubs are not as readily obtainable for the six years or if the instrument is not actively traded. Given that limited market data exists for these instruments, PacifiCorp uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on significant unobservable inputs.

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. Options components are valued using Black-Scholes-type option models, such as European option, Asian option, spread option and best-of option, with the appropriate forward price curve and other inputs.

The following table reconciles the beginning and ending balance of PacifiCorp's assets and liabilities measured at fair value on a recurring basis using significant Level 3 inputs (in millions):

	Commodity Derivatives
Balance, January 1, 2008	$ (311)
Unrealized gains (losses) included in regulatory assets	(103)
Purchases, sales, issuances and settlements	(7)
Net transfers into Level 3	13
Balance, December 31, 2008	$ (408)

PacifiCorp's long-term debt and current maturities of long-term debt are carried at cost in the Consolidated Financial Statements. The fair value of PacifiCorp's long-term debt has been estimated based on quoted market prices. The carrying amount of variable-rate long-term debt approximates fair value because of the frequent repricing of these instruments at market rates. The following table presents the carrying amount and estimated fair value of PacifiCorp's fixed-rate and variable-rate long-term debt, including the current portion as of December 31 (in millions):

	2008		**2007**	
	Carrying Amount	**Fair Value**	**Carrying Amount**	**Fair Value**
Long-term debt	$ 5,503	$ 5,769	$ 5,118	$ 5,350

(7) Risk Management and Hedging Activities

PacifiCorp is exposed to the impact of market fluctuations in commodity prices, principally natural gas and electricity. Interest rate risk exists on variable-rate debt, commercial paper and future debt issuances. PacifiCorp employs established policies and procedures to manage its risks associated with these market fluctuations using various commodity instruments, including forward contracts, options, swaps and other agreements. 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. PacifiCorp's portfolio of energy derivatives is substantially used for non-trading purposes. As of December 31, 2008 and 2007, PacifiCorp had no financial derivatives in effect relating to interest rate exposure.

The following table summarizes the various derivative mark-to-market positions included in the Consolidated Balance Sheet as of December 31, 2008 (in millions):

	Net Derivative Assets (Liabilities)[1]			Net Regulatory Assets (Liabilities)
	Assets	**Liabilities**	**Total**	
Commodity	$ 260	$ (620)	$ (360)	$ 442
Current	$ 174	$ (130)	$ 44	
Non-current	86	(490)	(404)	
Total	$ 260	$ (620)	$ (360)	

(1) Net derivative assets (liabilities) include $82 million of a net asset for cash collateral.

The following table summarizes the various derivative mark-to-market positions included in the Consolidated Balance Sheet as of December 31, 2007 (in millions):

	Net Derivative Assets (Liabilities)			Net Regulatory Assets (Liabilities)
	Assets	**Liabilities**	**Total**	
Commodity	$ 357	$ (614)	$ (257)	$ 257
Foreign currency	1	-	1	(1)
	$ 358	$ (614)	$ (256)	$ 256
Current	$ 143	$ (117)	$ 26	
Non-current	215	(497)	(282)	
Total	$ 358	$ (614)	$ (256)	

The following table summarizes the amount of the pre-tax unrealized gains and losses included within the Consolidated Statements of Operations associated with changes in the fair value of PacifiCorp's derivative contracts that are not included in rates (in millions):

	Years Ended December 31,		Nine-Month Period Ended
	2008	2007	December 31, 2006 (1)
Operating revenue	$ -	$ (6)	$ 29
Energy costs	-	7	(133)
Total unrealized gain (loss) on derivative contracts	$ -	$ 1	$ (104)

(1) During the nine-month period ended December 31, 2006, PacifiCorp reached a new general rate case stipulation with several parties in Utah and received approval from the OPUC for a new general rate case settlement in Oregon. Utah and Oregon together account for approximately 70% of PacifiCorp's retail electric operating revenues. Based on management's consideration of the two new rate settlements, as well as the power cost recovery adjustment mechanisms approved in Wyoming and California earlier in 2006, PacifiCorp changed its estimate of the contracts receiving recovery in rates. Effective July 21, 2006, PacifiCorp recorded a $40 million decrease in net regulatory assets for previously recorded net unrealized gains related to contracts that it determined were probable of being recovered in rates with a corresponding pre-tax charge to net income of $44 million and a pre-tax increase to AOCI of $4 million.

Realized and unrealized gains and losses on derivative contracts held for trading purposes are presented on a net basis in the Consolidated Statements of Operations as operating revenue. Unrealized gains and losses on electricity and natural gas derivative contracts not held for trading purposes are presented in the Consolidated Statements of Operations as operating revenue for sales contracts and as energy costs and operations and maintenance expense for purchase contracts and financial swap energy contracts. Realized gains and losses on physically settled derivative contracts not held for trading purposes are presented in the Consolidated Statements of Operations as operating revenue for sales contracts and as energy costs for purchase contracts. Realized gains and losses on non-physically settled forward purchase and sale derivative contracts not held for trading purposes are presented on a net basis in the Consolidated Statements of Operations as operating revenue. Realized gains and losses on financial swap energy contracts are presented in the Consolidated Statements of Operations as energy costs and operations and maintenance expense.

Cash Collateral

Amounts recognized for cash collateral received from others that was offset against net derivative assets totaled $78 million as of December 31, 2008 compared to $160 million of cash collateral provided to others that was offset against net derivative liabilities as of December 31, 2008. The amounts of cash collateral received or provided vary primarily based on changes in fair value of the related positions.

Weather Derivatives

PacifiCorp had a non-exchange-traded streamflow weather derivative contract to reduce PacifiCorp's exposure to variability in weather conditions that affect hydroelectric generation. The contract expired on September 30, 2006. PacifiCorp paid an annual premium in return for the right to make or receive payments if streamflow levels were above or below certain thresholds. PacifiCorp recognized a loss of $12 million during the nine-month period ended December 31, 2006. PacifiCorp currently has no streamflow or other weather derivative contracts.

(8) Short-Term Borrowings

Short-Term Debt

As of December 31, 2008, PacifiCorp had outstanding short-term debt borrowings of $85 million consisting of commercial paper at an average interest rate of 1.0%. As of December 31, 2007, PacifiCorp had no outstanding short-term debt borrowings.

Revolving Credit Agreements

As of December 31, 2008, PacifiCorp had $1.5 billion of total bank commitments under two unsecured revolving credit facilities. However, PacifiCorp's effective liquidity under these facilities was reduced by $105 million to $1.4 billion due to the Lehman Brothers Holdings Inc. ("Lehman") bankruptcy filing in September 2008. Lehman filed for protection under Chapter 11 of the Federal Bankruptcy Code in the United States Bankruptcy Court in the Southern District of New York. Lehman Brothers Bank, FSB and Lehman Commercial Paper, Inc., both subsidiaries of Lehman, have commitments totaling $105 million in PacifiCorp's $1.5 billion unsecured revolving credit facilities. The reduction in available capacity under the credit facilities as a result of the Lehman bankruptcy did not have a material adverse impact on PacifiCorp.

Adjusting for the Lehman bankruptcy, the first credit facility has $760 million of total bank commitments through July 6, 2011. The commitments reduce over time to $630 million of remaining availability for the year ending July 6, 2013. Adjusting for the Lehman bankruptcy, the second credit facility has $635 million of total bank commitments through October 23, 2012. Each credit facility includes a variable interest rate borrowing option based on the London Interbank Offered Rate, plus a margin that is currently 0.155% and varies based on PacifiCorp's credit ratings for its senior unsecured long-term debt securities. These credit facilities support PacifiCorp's commercial paper program, unenhanced variable-rate tax-exempt bond obligations and other short-term borrowing needs.

As of December 31, 2008, PacifiCorp had no borrowings outstanding under either credit facility but had letters of credit under both credit agreements totaling $220 million to support variable-rate tax-exempt bond obligations. In addition, the credit facilities supported $85 million of commercial paper borrowings and $38 million of unenhanced variable-rate tax-exempt bond obligations outstanding as of December 31, 2008. The remaining $1.1 billion of effective liquidity under the unsecured revolving credit facilities was available as of December 31, 2008.

As of December 31, 2007, PacifiCorp had no borrowings outstanding under either credit facility.

PacifiCorp's revolving credit and other financing agreements contain customary covenants and default provisions, including a covenant not to exceed a specified debt-to-capitalization ratio of 0.65 to 1.0. As of December 31, 2008, PacifiCorp was in compliance with the covenants of its revolving credit and other financing agreements.

(9) Long-Term Debt and Capital Lease Obligations

PacifiCorp's long-term debt and capital lease obligations were as follows as of December 31 (in millions):

	2008			2007	
	Par Value	Amount	Average Interest Rate	Amount	Average Interest Rate
First mortgage bonds:					
4.3% to 9.2%, due through 2013	$ 977	$ 976	6.9%	$ 1,390	6.5%
5.0% to 8.7%, due 2014 to 2018	721	720	5.5	221	5.3
6.7% to 8.5%, due 2021 to 2023	324	324	7.7	324	7.7
6.7% due 2026	100	100	6.7	100	6.7
7.7% due 2031	300	299	7.7	299	7.7
5.3% to 6.4%, due 2034 to 2038	2,350	2,345	6.0	2,046	5.9
Tax-exempt bond obligations:					
Variable rates, due 2013 (1) (2)	41	41	0.8	41	3.8
Variable rates, due 2014 to 2025 (2)	325	325	1.1	325	3.5
Variable rates, due 2024 (1) (2)	176	176	0.9	176	3.8
3.4% to 5.7%, due 2014 to 2025 (1)	184	184	4.5	183	4.5
6.2% due 2030	13	13	6.2	13	6.2
Total long-term debt	5,511	5,503		5,118	
Capital lease obligations:					
8.8% to 14.8%, due through 2036	65	65	11.6	49	11.3
Total long-term debt and capital lease obligations	$ 5,576	$ 5,568		$ 5,167	

Reflected as:

	2008	2007
Current portion of long-term debt and capital lease obligations	$ 144	$ 414
Long-term debt and capital lease obligations	5,424	4,753
Total long-term debt and capital lease obligations	$ 5,568	$ 5,167

(1) Secured by pledged first mortgage bonds generally at the same interest rates, maturity dates and redemption provisions as the tax-exempt bond obligations.

(2) 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 PacifiCorp's mortgage. Approximately $17.8 billion of the eligible assets (based on original cost) of PacifiCorp were subject to the lien of the mortgage as of December 31, 2008.

In January 2009, PacifiCorp issued $350 million of its 5.50% First Mortgage Bonds due January 15, 2019 and $650 million of its 6.00% First Mortgage Bonds due January 15, 2039.

In September 2008, PacifiCorp acquired $216 million of its insured variable-rate tax-exempt bond obligations due to the significant reduction in market liquidity for insured variable-rate obligations. In November 2008, the associated insurance and related standby bond purchase agreements were terminated and these variable-rate long-term debt obligations were remarketed with credit enhancement and liquidity support provided by $220 million of letters of credit issued under PacifiCorp's two unsecured revolving credit facilities.

In January 2008, PacifiCorp received regulatory authority from the OPUC and the Idaho Public Utilities Commission to issue up to an additional $2.0 billion of long-term debt. PacifiCorp must make a notice filing with the Washington Utilities and Transportation Commission prior to any future issuance. Also in January 2008, PacifiCorp filed a shelf registration statement with the United States Securities and Exchange Commission covering future first mortgage bond issuances. PacifiCorp's long-term debt issuances in January 2009 and during the year ended December 31, 2008 were covered under the above-noted regulatory authorities and shelf registration statement.

As of December 31, 2008, $4.3 billion of first mortgage bonds were redeemable at PacifiCorp's option at redemption prices dependent upon United States Treasury yields. As of December 31, 2008, $542 million of variable-rate tax-exempt bond obligations and $84 million of fixed-rate tax-exempt bond obligations were redeemable at PacifiCorp's option at par. The remaining long-term debt was not redeemable as of December 31, 2008.

As of December 31, 2008, PacifiCorp had $517 million of letters of credit available to provide credit enhancement and liquidity support for variable-rate tax-exempt bond obligations totaling $504 million plus interest. These committed bank arrangements were fully available at December 31, 2008 and expire periodically through May 2012.

In addition, as of December 31, 2008, PacifiCorp had approximately $18 million of letters of credit available to provide credit support for certain transactions as requested by third parties. These committed bank arrangements were all fully available as of December 31, 2008 and have provisions that automatically extend the annual expiration dates for an additional year unless the issuing bank elects not to renew a letter of credit prior to the expiration date.

PacifiCorp's letters of credit generally contain similar covenants and default provisions to those contained in PacifiCorp's revolving credit agreement, including a covenant not to exceed a specified debt-to-capitalization ratio of 0.65 to 1.0. PacifiCorp monitors these covenants on a regular basis in order to ensure that events of default will not occur and as of December 31, 2008, PacifiCorp was in compliance with these covenants.

PacifiCorp has entered into long-term agreements that expire at various dates through October 2036 for transportation services, purchase power agreements, real estate and for the use of certain equipment that qualify as capital leases. The transportation services agreements included as capital leases are for the right to use pipeline facilities to provide natural gas to three of PacifiCorp's generating facilities. Net assets accounted for as capital leases of $65 million and $49 million as of December 31, 2008 and 2007, respectively, were included in property, plant and equipment, net in the Consolidated Balance Sheets.

The annual maturities of long-term debt and capital lease obligations for the years beginning January 1, 2009 and thereafter, excluding unamortized discounts, are as follows (in millions):

	Long-term Debt	Capital Lease Obligations[1]	Total
2009	$ 139	$ 13	$ 152
2010	14	9	23
2011	587	8	595
2012	17	8	25
2013	261	12	273
Thereafter	4,493	106	4,599
Total	5,511	156	5,667
Amounts representing interest	-	(91)	(91)
Total	$ 5,511	$ 65	$ 5,576

(1) Excluded from these amounts are approximately $46 million of capital lease executory costs, including taxes, maintenance and insurance.

(10) Asset Retirement Obligations

PacifiCorp estimates its ARO 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. Changes in estimates could occur for a number of reasons, including plan revisions, inflation and changes in the amount and timing of the expected work.

PacifiCorp does not recognize liabilities for AROs for which the fair value cannot be reasonably estimated. Due to the indeterminate removal date, the fair value of the associated liabilities on certain transmission, distribution and other assets cannot currently be estimated and no amounts are recognized in the accompanying Consolidated Financial Statements other than those included in the regulatory removal cost liability established via approved depreciation rates.

The change in the balance of the total ARO liability, which is included in other long-term liabilities and other current liabilities, is summarized as follows as of December 31 (in millions):

	2008	2007
Balance, January 1	$ 185	$ 221
Additions	2	2
Retirements	(24)	(27)
Change in estimated costs [1]	(8)	(22)
Accretion	10	11
Balance, December 31	$ 165	$ 185

(1) Results from changes in the timing and amounts of estimated cash flows for certain plant and mine reclamation.

PacifiCorp's coal mining operations are subject to the Surface Mining Control and Reclamation Act of 1977 and similar state statutes that establish operational, reclamation and closure standards that must be met during and upon completion of mining activities. These statutes mandate that mining property be restored consistent with specific standards and the approved reclamation plan. PacifiCorp incurs expenditures for both ongoing and final reclamation. PacifiCorp's ARO liabilities consist principally of mine reclamation obligations for its Jim Bridger mine that were $84 million and $110 million as of December 31, 2008 and 2007, respectively.

PacifiCorp, by contract with Idaho Power Company, the minority owner of the Bridger Coal Company, maintains a trust for final reclamation of the Jim Bridger mine. The fair value of the assets held in trust was $79 million and $117 million as of December 31, 2008 and 2007, respectively, and is included in other current assets and deferred charges, investments and other, including the minority interest joint-owner portions, in the Consolidated Balance Sheets.

Certain of PacifiCorp's decommissioning and reclamation obligations relate to jointly owned facilities and mine sites. For decommissioning, PacifiCorp is committed to pay a proportionate share of the decommissioning costs based upon its ownership percentage, or in the case of mine reclamation obligations, PacifiCorp has committed to pay a proportionate share of mine 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's estimated share of the decommissioning and reclamation obligations are primarily recorded as ARO liabilities.

(11) Employee Benefit Plans

PacifiCorp sponsors defined benefit pension plans that cover the majority of its employees and also provides certain postretirement health care and life insurance benefits through various plans for eligible retirees. In addition, PacifiCorp sponsors a defined contribution 401(k) employee savings plan (the "401(k) Plan"). Non-union employees hired on or after January 1, 2008 and certain union new hires are not eligible to participate in the PacifiCorp Retirement Plan (the "Retirement Plan"). These employees are eligible to receive enhanced benefits under the 401(k) Plan.

Pension and Other Postretirement Benefit Plans

PacifiCorp's pension plans include a non-contributory defined benefit pension plan, the Retirement Plan; the Supplemental Executive Retirement Plan (the "SERP"); and certain joint trust union plans to which PacifiCorp contributes on behalf of certain bargaining units. Benefits for certain union employees covered 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. At December 31, 2008, all non-union Retirement Plan participants, as well as certain union participants, earn benefits based on a cash balance formula. Refer to the discussion of curtailments below.

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. PacifiCorp funds these other postretirement benefits through a combination of funding vehicles. PacifiCorp also contributes to joint trust union plans for postretirement benefits offered to certain bargaining units.

Measurement Date Change

PacifiCorp adopted the measurement date provisions of SFAS No. 158 at December 31, 2008, which requires that an employer measure plan assets and benefit obligations at the end of the employer's fiscal year. Effective December 31, 2008, PacifiCorp changed its measurement date from September 30 to December 31 and recorded a $14 million transitional adjustment. The components of the measurement date change transitional adjustment were as follows on a pre-tax basis (in millions):

	Pension	Other Postretirement	Total
Service cost	$ 7	$ 2	$ 9
Interest cost	16	8	24
Expected return on plan assets	(18)	(7)	(25)
Net amortization	2	4	6
Total	$ 7	$ 7	$ 14

The $14 million transitional adjustment includes $12 million recorded as an increase in regulatory assets for the portion considered probable of recovery in rates and $2 million recorded as a reduction ($1 million after-tax) in retained earnings for the portion not considered probable of recovery in rates. The $12 million increase to regulatory assets will be amortized over three to 10 years based on agreements with various state regulatory commissions. The recognition of service cost, interest cost and expected return on plan assets, totaling $8 million, resulted in an increase in pension and other postretirement liabilities. The $6 million net amortization represents recognition of prior service cost, net transition obligation and actuarial net loss and resulted in a reduction in regulatory assets.

Curtailments

In August 2008, non-union employee participants in the Retirement Plan were offered the option to continue to receive pay credits in their current cash balance formula of the Retirement Plan or receive equivalent fixed contributions to the 401(k) Plan. The election was effective January 1, 2009, and resulted in the recognition of a $38 million curtailment gain. PacifiCorp recorded $36 million of the curtailment gain as a reduction to regulatory assets as of December 31, 2008, representing the amount to be returned to customers in rates. The reduction to the regulatory asset will be amortized over a period of three to 10 years based on agreements with various state regulatory commissions.

Effective December 31, 2007, Local Union No. 659 of the International Brotherhood of Electrical Workers ("Local 659") elected to cease participation in the Retirement Plan and participate only in the 401(k) Plan with enhanced benefits. As a result of this election, the Local 659 participants' Retirement Plan benefits were frozen as of December 31, 2007. This change resulted in a $2 million curtailment gain that was recorded as a reduction to regulatory assets as of December 31, 2008 based on the requirement to return the amount to customers in rates. It will be amortized over a period of three to 10 years based on agreements with various state regulatory commissions. Also as a result of this change, PacifiCorp's pension liability and regulatory assets each decreased by $13 million.

Change in Benefit Formula

Effective June 1, 2007, PacifiCorp switched from a traditional final-average-pay formula for the Retirement Plan to a cash balance formula for its non-union employees. As a result of the change, benefits under the traditional final-average-pay formula were frozen as of May 31, 2007 for non-union employees, and PacifiCorp's pension liability and regulatory assets each decreased by $111 million.

Net Periodic Benefit Cost

For purposes of calculating the expected return on plan assets, a market-related value is used. The market-related value of plan assets is calculated by spreading the difference between expected and actual investment returns over a five-year period beginning after the first year in which they occur. In addition, as differences between expected and actual investment returns are admitted into the market-related value of plan assets, the corresponding gains or losses are then amortized and included in the net amortization component of net periodic benefit cost.

Net periodic benefit cost for the pension and other postretirement benefit plans included the following components (in millions):

	Pension			Other Postretirement		
	Years Ended December 31,		Nine-Month Period Ended December 31,	Years Ended December 31,		Nine-Month Period Ended December 31,
	2008 [(2)]	2007	2006	2008 [(2)]	2007	2006
Service cost [(1)]	$ 27	$ 29	$ 22	$ 7	$ 7	$ 7
Interest cost	67	71	56	33	33	25
Expected return on plan assets	(72)	(68)	(54)	(28)	(26)	(19)
Net amortization	7	23	23	15	19	15
Cost of termination benefits	-	1	2	-	-	-
Curtailment loss (gain)	(2)	-	1	-	-	-
Net periodic benefit cost	$ 27	$ 56	$ 50	$ 27	$ 33	$ 28

(1) Service cost excludes $13 million and $12 million of contributions to the joint trust union plans during the years ended December 31, 2008 and 2007, respectively, and $6 million during the nine-month period ended December 31, 2006.

(2) Excludes impact of the measurement date change and the portion of the curtailment gains required to be returned to customers in rates. Refer to "Measurement Date Change" and "Curtailments" above.

Funded Status

The following table is a reconciliation of the fair value of plan assets as of the end of the year (in millions):

	Pension		Other Postretirement	
	Years Ended December 31,		Years Ended December 31,	
	2008	2007	2008	2007
Plan assets at fair value, beginning of year	$ 963	$ 884	$ 378	$ 318
Employer contributions	70	80	42	46
Participant contributions	-	-	14	11
Actual return on plan assets	(224)	118	(103)	46
Benefits paid	(117)	(119)	(47)	(43)
Plan assets at fair value, end of year	$ 692	$ 963	$ 284	$ 378

The following table is a reconciliation of the benefit obligations as of the end of the year (in millions):

	Pension		Other Postretirement	
	Years Ended December 31,		Years Ended December 31,	
	2008	2007	2008	2007
Benefit obligation, beginning of year	$ 1,111	$ 1,333	$ 536	$ 566
Service cost (1)	34	29	9	7
Interest cost (1)	83	71	41	33
Participant contributions	-	-	14	11
Plan amendments	(7)	(130)	(12)	-
Curtailment	(13)	-	-	-
Actuarial gain	(21)	(74)	(56)	(40)
Benefits paid, net of Medicare subsidy	(117)	(119)	(43)	(41)
Cost of termination benefits	-	1	-	-
Benefit obligation, end of year	$ 1,070	$ 1,111	$ 489	$ 536
Accumulated benefit obligation, end of year	$ 1,048	$ 1,061		

(1) Included in the pension and other postretirement liabilities increase in connection with the measurement date change in 2008 was additional service cost of $7 million and $2 million and additional interest cost of $16 million and $8 million for the pension and other postretirement benefit plans, respectively.

The funded status of the plans and the amounts recognized in the Consolidated Balance Sheets are as follows as of December 31 (in millions):

	Pension		Other Postretirement	
	2008	2007	2008	2007
Plan assets at fair value, end of year	$ 692	$ 963	$ 284	$ 378
Less – Benefit obligation, end of year	1,070	1,111	489	536
Funded status	(378)	(148)	(205)	(158)
Contributions after the measurement date but before year-end	-	-	-	12
Amounts recognized in the Consolidated Balance Sheets	$ (378)	$ (148)	$ (205)	$ (146)
Amounts recognized in the Consolidated Balance Sheets:				
Other current liabilities	$ (4)	$ (4)	$ -	$ -
Other long-term liabilities	(374)	(144)	(205)	(146)
Amounts recognized	$ (378)	$ (148)	$ (205)	$ (146)

The SERP has no plan assets; however, 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. The cash surrender value of all of the policies included in the Rabbi trust, net of amounts borrowed against the cash surrender value, plus the fair market value of other Rabbi trust investments, was $38 million and $40 million as of December 31, 2008 and 2007, respectively. These assets are not included in the plan assets in the above table, but are reflected in the Consolidated Balance Sheets. The portion of the pension plans' projected benefit obligation related to the SERP was $50 million and $52 million as of December 31, 2008 and 2007, respectively. The SERP's accumulated benefit obligation totaled $50 million and $52 million as of December 31, 2008 and 2007, respectively.

Unrecognized Amounts

The portion of the funded status of the plans not yet recognized in net periodic benefit cost is as follows as of December 31 (in millions):

	Pension		Other Postretirement	
	2008	2007	2008	2007
Amounts not yet recognized as components of net periodic benefit cost:				
Net loss	$ 508	$ 250	$ 128	$ 45
Prior service cost (credit)	(68)	(115)	1	17
Net transition obligation	-	3	45	60
Regulatory deferrals (1)	(32)	-	6	-
Total	$ 408	$ 138	$ 180	$ 122

(1) Consists of amounts related to the portion of the curtailment gains and the measurement date change transitional adjustment that are considered probable of inclusion in rates.

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2008 and 2007 is as follows (in millions):

	Regulatory Asset	Accumulated Other Comprehensive Loss, Net	Total
Pension			
Balance, January 1, 2007	$ 405	$ 9	$ 414
Net gain arising during the year	(121)	(2)	(123)
Prior service credit arising during the year	(129)	(1)	(130)
Net amortization	(23)	-	(23)
Total	(273)	(3)	(276)
Balance, December 31, 2007	$ 132	$ 6	$ 138
Balance, January 1, 2008	$ 132	$ 6	$ 138
Net (gain) loss arising during the year	293	(2)	291
Prior service credit arising during the year	(7)	-	(7)
Curtailment gains	(11)	-	(11)
Measurement date change	6		6
Net amortization (1)	(9)	-	(9)
Total	272	(2)	270
Balance, December 31, 2008	$ 404	$ 4	$ 408

	Regulatory Asset	Deferred Income Taxes	Total
Other Postretirement			
Balance, January 1, 2007	$ 161	$ 40	$ 201
Net gain arising during the year	(47)	(13)	(60)
Net amortization	(19)	-	(19)
Total	(66)	(13)	(79)
Balance, December 31, 2007	$ 95	$ 27	$ 122
Balance, January 1, 2008	$ 95	$ 27	$ 122
Net loss (gain) arising during the year	91	(7)	84
Prior service credit arising during the year	(13)	-	(13)
Measurement date change	6	-	6
Net amortization (1)	(19)	-	(19)
Total	65	(7)	58
Balance, December 31, 2008	$ 160	$ 20	$ 180

(1) Included in the regulatory asset decrease in connection with the measurement date change in 2008 was additional amortization of $2 million and $4 million for the pension and other postretirement benefit plans, respectively.

The net loss, prior service credit, net transition obligation and regulatory deferrals that will be amortized in 2009 into net periodic benefit cost are estimated to be as follows (in millions):

	Net Loss	Prior Service Credit	Net Transition Obligation	Regulatory Deferrals	Total
Pension benefits	$ 18	$ (8)	$ -	$ (8)	$ 2
Other postretirement benefits	-	-	12	1	13
Total	$ 18	$ (8)	$ 12	$ (7)	$ 15

Plan Assumptions

Assumptions used to determine benefit obligations and net benefit cost were as follows:

	Pension			Other Postretirement		
	Years Ended December 31,		Nine-Month Period Ended December 31,	Years Ended December 31,		Nine-Month Period Ended December 31,
	2008	2007	2006	2008	2007	2006
Benefit obligations as of the measurement date:						
Discount rate	6.90%	6.30%	5.85%	6.90%	6.45%	6.00%
Rate of compensation increase	3.50	4.00	4.00	N/A	N/A	N/A
Net benefit cost for the period ended:						
Discount rate	6.30%	5.76%	5.75%	6.45%	6.00%	5.75%
Expected return on plan assets	7.75	8.00	8.50	7.75	8.00	8.50
Rate of compensation increase	4.00	4.00	4.00	N/A	N/A	N/A

In establishing its assumption as to the expected return on plan assets, PacifiCorp reviews the expected asset allocation and develops return assumptions for each asset class based on historical performance and forward-looking views of the financial markets.

Assumed health care cost trend rates as of the measurement date:

	2008	2007
Health care cost trend rate assumed for next year – under 65	8%	9%
Health care cost trend rate assumed for next year – over 65	6	7
Rate that the cost trend rate gradually declines to	5	5
Year that rate reaches the rate it is assumed to remain at – under 65	2012	2012
Year that rate reaches the rate it is assumed to remain at – over 65	2010	2010

A one-percentage-point change in assumed health care cost trend rates would have the following effects (in millions):

	Increase (Decrease)	
	One Percentage-Point Increase	One Percentage-Point Decrease
Effect on total service and interest cost	$ 3	$ (2)
Effect on other postretirement benefit obligation	31	(26)

Contributions and Benefit Payments

Employer contributions to the pension, other postretirement benefit plans and the joint trust union plans are expected to be $54 million, $25 million and $13 million, respectively, for 2009. Funding to the established pension trust is based upon the actuarially determined costs of the plan and the requirement of the Internal Revenue Code, the Employee Retirement Income Security Act of 1974 and the Pension Protection Act of 2006, as amended. PacifiCorp's policy is to contribute to its other postretirement benefit plan an amount equal to the sum of the net periodic cost and the expected Medicare subsidy.

The Plan's expected benefit payments to participants for its pension and other postretirement benefit plans for 2009 through 2013 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments			
		Other Postretirement		
	Pension	Gross	Medicare Subsidy	Net of Subsidy
2009	$ 90	$ 36	$ (3)	$ 33
2010	93	37	(3)	34
2011	95	38	(4)	34
2012	96	39	(4)	35
2013	101	40	(5)	35
2014 – 2018	504	220	(30)	190

Investment Policy and Asset Allocation

PacifiCorp's investment policy for its pension and other postretirement benefit plans is to balance risk and return through a diversified portfolio of equity securities, fixed income securities and other alternative investments. Asset allocation for the pension and other postretirement benefit plans are as indicated in the tables below. Maturities for fixed income securities are managed to targets consistent with prudent risk tolerances. Sufficient liquidity is maintained to meet near-term benefit payment obligations. The plans retain outside investment advisors to manage plan investments within the parameters outlined by PacifiCorp's Pension Investment Committee. The weighted-average return on assets assumption is based on historical performance for the types of assets in which the plans invest.

PacifiCorp's pension plan trust includes a separate account that is used to fund benefits for the other postretirement benefit plan. In addition to this separate account, the assets for other postretirement benefits are held in two Voluntary Employees' Beneficiaries Association ("VEBA") Trusts, each of which has its own investment allocation strategies. PacifiCorp's asset allocation (percentage of plan assets) as of December 31 was as follows:

	Pension Plan Trust			VEBA Trusts		
	2008	2007	Target	2008	2007	Target
Equity securities	49%	56%	53 – 57%	64%	64%	63 – 67%
Debt securities	40	35	33 – 37	36	36	33 – 37
Other	11	9	8 – 12	-	-	-
	100%	100%		100%	100%	

PacifiCorp's benefit plan asset allocations were impacted by the highly volatile capital markets in the second half of 2008.

Defined Contribution Plan

PacifiCorp's 401(k) Plan covers substantially all employees. PacifiCorp's contributions are based primarily on each participant's level of contribution and cannot exceed the maximum allowable for tax purposes to the 401(k) Plan. PacifiCorp's contributions were $23 million and $19 million during the years ended December 31, 2008 and 2007, respectively, and $16 million during the nine-month period ended December 31, 2006.

Severance

PacifiCorp incurred no severance expense during the year ended December 31, 2008, $4 million during the year ended December 31, 2007 and $31 million during the nine-month period ended December 31, 2006.

(12) Income Taxes

Income tax expense (benefit) consists of the following (in millions):

	Years Ended December 31, 2008	Years Ended December 31, 2007	Nine-Month Period Ended December 31, 2006
Current:			
Federal	$ (64)	$ 162	$ 71
State	(6)	19	9
Total	(70)	181	80
Deferred:			
Federal	276	41	11
State	36	6	1
Total	312	47	12
Investment tax credits	(4)	(8)	(6)
Total income tax expense	$ 238	$ 220	$ 86

A reconciliation of the federal statutory tax rate to the effective tax rate applicable to income before income tax expense is as follows:

	Years Ended December 31, 2008	Years Ended December 31, 2007	Nine-Month Period Ended December 31, 2006
Federal statutory tax rate	35%	35%	35%
State taxes, net of federal benefit	3	3	4
Effect of regulatory treatment of depreciation differences	1	2	6
Tax reserves	-	(1)	(5)
Tax credits (1)	(5)	(3)	(4)
Other	-	(3)	(1)
Effective income tax rate	34%	33%	35%

(1) Primarily attributable to the impact of federal renewable electricity production tax credits related to qualifying wind-powered generating facilities that extend 10 years from the date the facilities were placed in service.

The net deferred tax liability consists of the following as of December 31 (in millions):

	2008	2007
Deferred tax assets:		
Regulatory liabilities	$ 319	$ 311
Employee benefits	249	138
Derivative contracts	169	107
Other	153	167
	890	723
Deferred tax liabilities:		
Property, plant and equipment	(1,940)	(1,641)
Regulatory assets	(881)	(695)
Other	(20)	(33)
	(2,841)	(2,369)
Net deferred tax liability	$ (1,951)	$ (1,646)
Reflected as:		
Deferred income taxes – current assets	$ 74	$ 55
Deferred income taxes-non – current liabilities	(2,025)	(1,701)
	$ (1,951)	$ (1,646)

The sale of PacifiCorp to MEHC on March 21, 2006 triggered certain tax related events that remain unsettled. PacifiCorp does not believe that the tax, if any, arising from the ultimate settlement of these events will have a material impact on its consolidated financial results.

PacifiCorp adopted FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes–an interpretation of FASB Statement No.* 109 ("FIN 48"), effective January 1, 2007 and had a net asset of $22 million for uncertain tax positions. PacifiCorp recognized a net increase in the asset of $22 million as a cumulative effect of adopting FIN 48, which was offset by increases in beginning retained earnings of $13 million and deferred income tax liabilities of $9 million in the Consolidated Balance Sheets. The $22 million was included in other long-term liabilities in the Consolidated Balance Sheets.

As of December 31, 2008 and 2007, PacifiCorp had a net asset of $13 million for uncertain tax positions. As of December 31, 2008 and 2007, the net asset for uncertain tax positions included $14 million and $15 million, respectively, of tax positions that, if recognized, would have an impact on the effective tax rate. The remaining unrecognized tax benefits relate to positions for which ultimate deductibility is highly certain but for which there is uncertainty as to the timing of such deductibility. Recognition of these tax benefits, other than applicable interest and penalties, would not affect PacifiCorp's effective tax rate. The current portion of uncertain tax positions is included in accrued taxes at December 31, 2008 and other current assets at December 31, 2007 and the non-current portion is included in other long-term liabilities in the Consolidated Balance Sheets.

(13) Commitments and Contingencies

Legal Matters

PacifiCorp is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. PacifiCorp does not believe that such normal and routine litigation will have a material effect on its consolidated financial results. PacifiCorp is also involved in other kinds of legal actions, some of which assert or may assert claims or seek to impose fines and penalties in substantial amounts and are described below.

In February 2007, the Sierra Club and the Wyoming Outdoor Council filed a complaint against PacifiCorp in the federal district court in Cheyenne, Wyoming, alleging violations of the Wyoming state opacity standards at PacifiCorp's Jim Bridger plant in Wyoming. Under Wyoming state requirements, which are part of the Jim Bridger plant's Title V permit and are enforceable by private citizens under the federal Clean Air Act, a potential source of pollutants such as a coal-fired generating facility must meet minimum standards for opacity, which is a measurement of light that is obscured in the flue of a generating facility. The complaint alleges thousands of violations of asserted six-minute compliance periods and seeks an injunction ordering the Jim Bridger plant's compliance with opacity limits, civil penalties of $32,500 per day per violation, and the plaintiffs' costs of litigation. The court granted a motion to bifurcate the trial into separate liability and remedy phases. In March 2008, the court indefinitely postponed the date for the liability-phase trial. The remedy-phase trial has not yet been scheduled. The court also has before it a number of motions on which it has not yet ruled. PacifiCorp believes it has a number of defenses to the claims. PacifiCorp intends to vigorously oppose the lawsuit but cannot predict its outcome at this time. PacifiCorp has already committed to invest at least $812 million in pollution control equipment at its generating facilities, including the Jim Bridger plant. This commitment is expected to significantly reduce system-wide emissions, including emissions at the Jim Bridger plant.

Environmental Regulation

Environmental Matters

PacifiCorp is subject to federal, state and local laws and regulations regarding air and water quality, hazardous and solid waste disposal and other environmental matters that have the potential to impact PacifiCorp's current and future operations. PacifiCorp believes it is in material compliance with current environmental requirements.

New Source Review

As part of an industry-wide investigation to assess compliance with the New Source Review ("NSR") and Prevention of Significant Deterioration ("PSD") provisions, the United States Environmental Protection Agency (the "EPA") has requested from numerous utilities information and supporting documentation regarding their capital projects for various generating facilities. Between 2001 and 2003, PacifiCorp responded to requests for information relating to its capital projects at its generating facilities and has been engaged in periodic discussions with the EPA over several years regarding PacifiCorp's historical projects and their compliance with NSR and PSD provisions. An NSR enforcement case against another utility has been decided by the United States Supreme Court, holding that an increase in annual emissions of a generating facility, when combined with a modification (i.e., a physical or operational change), may trigger NSR permitting. PacifiCorp cannot predict the outcome of its discussions with the EPA at this time; however, PacifiCorp could be required to install additional emissions controls, and incur additional costs and penalties, in the event it is determined that PacifiCorp's historical projects did not meet all regulatory requirements.

Accrued Environmental Costs

PacifiCorp is fully or partly responsible for environmental remediation at various contaminated sites, including sites that are or were part of PacifiCorp's operations and sites owned by third parties. PacifiCorp accrues environmental remediation expenses when the expenses are believed to be probable and can be reasonably estimated. The quantification of environmental exposures is based on many factors, including changing laws and regulations, advancements in environmental technologies, the quality of available site-specific information, site investigation results, expected remediation or settlement timelines, PacifiCorp's proportionate responsibility, contractual indemnities and coverage provided by insurance policies. 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 costs of PacifiCorp. The liability recorded as of December 31, 2008 and 2007 was $26 million and $29 million, respectively, and is included in other current liabilities and other long-term liabilities in the Consolidated Balance Sheets. Environmental remediation liabilities that separately result from the normal operation of long-lived assets and that are associated with the retirement of those assets are separately accounted for as AROs. The December 31, 2008 recorded liability included $18 million of discounted liabilities. Had none of the liabilities included in the $26 million balance recorded as of December 31, 2008 been discounted, the total would have been $30 million. The expected undiscounted payments for each of the years ending December 31, 2009 through 2013 and thereafter are as follows: $8 million in 2009, $4 million in 2010, $2 million in 2011, $1 million in 2012, $1 million in 2013 and $14 million thereafter.

Hydroelectric Relicensing

PacifiCorp's hydroelectric portfolio consists of 47 generating facilities with an aggregate facility net owned capacity of 1,158 MW. The Federal Energy Regulatory Commission (the "FERC") regulates 98% of the net capacity of this portfolio through 16 individual licenses, which typically have terms of 30 to 50 years. In April 2008 and June 2008, the FERC issued new licenses for the Prospect and the Lewis River hydroelectric systems, respectively, as described below. PacifiCorp's Klamath hydroelectric system is the remaining hydroelectric generating facility actively engaged in the relicensing process with the FERC. Hydroelectric relicensing and the related environmental compliance requirements and litigation are subject to uncertainties. PacifiCorp expects that future costs relating to these matters will be significant and will consist primarily of additional relicensing costs, as well as ongoing operations and maintenance expense and capital expenditures required by its hydroelectric licenses. Electricity generation reductions may result from the additional environmental requirements. PacifiCorp had incurred $57 million and $89 million in costs, included in construction work-in-progress within property, plant and equipment, net, as of December 31, 2008 and 2007, respectively, for ongoing hydroelectric relicensing. Refer to Hydroelectric Commitments section below for a discussion regarding existing capital expenditures commitments related to hydroelectric licenses under which PacifiCorp is currently operating.

Klamath Hydroelectric System – Klamath River, Oregon and California

In February 2004, PacifiCorp filed with the FERC a final application for a new license to operate the 169-MW Klamath hydroelectric system in anticipation of the March 2006 expiration of the existing license. PacifiCorp is currently operating under an annual license issued by the FERC and expects to continue operating under annual licenses until the relicensing process is complete. As part of the relicensing process, the FERC is required to perform an environmental review and in November 2007, the FERC issued its final environmental impact statement. The United States Fish and Wildlife Service and the National Marine Fisheries Service issued final biological opinions in December 2007 analyzing the Klamath hydroelectric system's impact on endangered species under a new FERC license consistent with the FERC staff's recommended license alternative and terms and conditions issued by the United States Departments of the Interior and Commerce. These terms and conditions include construction of upstream and downstream fish passage facilities at the Klamath hydroelectric system's four mainstem dams. PacifiCorp will need to obtain water quality certifications from Oregon and California prior to the FERC issuing a final license. PacifiCorp currently has water quality applications pending in Oregon and California.

In November 2008, PacifiCorp signed a non-binding agreement in principle (the "AIP") that lays out a framework for the disposition of PacifiCorp's Klamath hydroelectric system relicensing process, including a path toward dam transfer and removal by an entity other than PacifiCorp no earlier than 2020. Parties to the AIP are PacifiCorp, the United States Department of the Interior, the State of Oregon and the State of California. Any transfer of facilities and subsequent removal are contingent on PacifiCorp reaching a comprehensive final settlement agreement with the AIP signatories and other stakeholders. Negotiations on a final agreement have begun and the AIP states that a final agreement is expected no later than June 30, 2009. As provided in the AIP, PacifiCorp's support for a definitive settlement will depend on the inclusion of protection for PacifiCorp and its customers from dam removal costs and liabilities.

The AIP includes provisions to:

- Perform studies and implement certain measures designed to benefit aquatic species and their habitat in the Klamath Basin;
- Support and implement legislation in Oregon authorizing a customer surcharge intended to cover potential dam removal; and
- Require parties to support proposed federal legislation introduced to facilitate a final agreement.

Assuming a final agreement is reached, the United States government will conduct scientific and engineering studies and consult with state, local and tribal governments and other stakeholders, as appropriate, to determine by March 31, 2012 whether the benefits of dam removal will justify the costs.

In addition to signing the AIP, PacifiCorp recently provided both the United States Fish and Wildlife Service and the National Marine Fisheries Service an interim conservation plan aimed at providing additional protections for endangered species in the Klamath Basin. PacifiCorp is currently collaborating with both agencies to implement the plan.

As of December 31, 2008 and 2007, PacifiCorp had $57 million and $48 million, respectively, in costs related to the relicensing of the Klamath hydroelectric system included in construction work-in-progress within property, plant and equipment, net in the Consolidated Balance Sheets.

Lewis River Hydroelectric System – Lewis River, Washington

PacifiCorp filed new license applications with the FERC for the 136-MW Merwin and 240-MW Swift No. 1 hydroelectric facilities in April 2004. An application for a new license for the 134-MW Yale hydroelectric facility 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 26 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 facilities. As part of this settlement agreement, PacifiCorp agreed to implement certain protection, mitigation and enhancement measures prior to and during a proposed 50-year license period. In June 2008, the FERC issued new individual licenses for the Merwin, Swift No. 1 and Yale hydroelectric facilities, each for a period of 50 years, effective June 1, 2008. In July 2008, PacifiCorp filed a motion of request for clarification or rehearing on certain items, which were subsequently addressed by the FERC in its October 2008 order on rehearing. In October 2008, subsequent to the FERC's final order, $36 million in costs to relicense these facilities were transferred from construction work-in-progress to property, plant and equipment.

Prospect Hydroelectric System – Rogue River, Oregon

In June 2003, PacifiCorp submitted a final license application to the FERC for the Prospect Nos. 1, 2 and 4 hydroelectric facilities, with total nameplate ratings of 37 MW. In 2008, the FERC issued a new license for a period of 30 years effective April 1, 2008. Subsequent to the issuance of the new license, $7 million of costs incurred to relicense the Prospect hydroelectric system were transferred from construction work-in-progress to property, plant and equipment.

Hydroelectric Commitments

Some of PacifiCorp's hydroelectric licenses contain requirements for PacifiCorp to make certain capital expenditures related to its hydroelectric facilities. PacifiCorp estimates it is obligated to make capital expenditures of approximately $278 million over the next 10 years related to these licenses.

FERC Issues

Northwest Refund Case

In June 2003, the FERC terminated its proceeding relating to the possibility of requiring refunds for wholesale spot-market bilateral sales in the Pacific Northwest between December 2000 and June 2001. The FERC concluded that ordering refunds would not be an appropriate resolution of the matter. In November 2003, the FERC issued its final order denying rehearing. Several market participants, excluding PacifiCorp, filed petitions in the United States Court of Appeals for the Ninth Circuit (the "Ninth Circuit") for review of the FERC's final order. In August 2007, the Ninth Circuit concluded that the FERC failed to adequately explain how it considered or examined new evidence showing intentional market manipulation in California and its potential ties to the Pacific Northwest and that the FERC should not have excluded from the Pacific Northwest refund proceeding purchases of energy made by the California Energy Resources Scheduling ("CERS") division in the Pacific Northwest spot market. The Ninth Circuit remanded the case to the FERC to (i) address the new market manipulation evidence in detail and account for it in any future orders regarding the award or denial of refunds in the proceedings, (ii) include sales to CERS in its analysis, and (iii) further consider its refund decision in light of related, intervening opinions of the court. The Ninth Circuit offered no opinion on the FERC's findings based on the record established by the administrative law judge and did not rule on the merits of the FERC's November 2003 decision to deny refunds. Due to the remand, PacifiCorp cannot predict the impact of this ruling at this time.

Purchase Obligations

PacifiCorp has the following unconditional purchase obligations as of December 31, 2008 (in millions) that are not reflected in the Consolidated Balance Sheet:

	Payments Due During the Years Ending December 31,						
	2009	**2010**	**2011**	**2012**	**2013**	**Thereafter**	**Total**
Purchased electricity	$ 419	$ 389	$ 254	$ 176	$ 171	$ 1,628	$ 3,037
Fuel	519	436	259	141	144	1,106	2,605
Construction	923	392	97	42	7	2	1,463
Transmission	80	76	70	63	59	545	893
Operating leases	5	4	4	4	3	36	56
Other	43	25	19	15	14	126	242
Total commitments	$1,989	$1,322	$ 703	$ 441	$ 398	$ 3,443	$ 8,296

Purchased Electricity

As part of its energy resource portfolio, PacifiCorp acquires a portion of its electricity through long-term purchases and exchange agreements. PacifiCorp has several power purchase agreements with wind-powered and other generating facilities that are not included in the table above as the payments are based on the amount of energy generated and there are no minimum payments. Purchased electricity, including purchases under those contracts that are not included in the above table and purchases of short-term electricity, were $759 million and $793 million for the years ended December 31, 2008 and 2007, respectively, and $605 million for the nine-month period ended December 31, 2006. These amounts are net of the effects of bookouts and trading activities.

Included in the minimum fixed annual payments for purchased electricity above are commitments to purchase electricity from several hydroelectric systems under long-term arrangements with public utility districts. These purchases are made on a “cost-of-service” basis for a stated percentage of system output and for a like percentage of system operating expenses and debt service. These costs are included in energy costs in the Consolidated Statements of Operations. PacifiCorp is required to pay its portion of operating costs and its portion of the debt service, whether or not any electricity is produced. These arrangements accounted for less than 5% of PacifiCorp’s 2008, 2007 and 2006 energy sources.

Fuel

PacifiCorp has “take or pay” coal and natural gas contracts that require minimum payments.

Construction

PacifiCorp has an ongoing construction program to meet increased electricity usage, customer growth and system reliability objectives. As of December 31, 2008, PacifiCorp had estimated long-term purchase obligations related to its construction program primarily for new wind-powered generating facilities and for certain segments of the Energy Gateway Transmission Expansion Project. Amounts included in the purchase obligations table above relate to firm commitments. The following discussion describes overall commitments related to those entered into as a result of MEHC’s acquisition of PacifiCorp, as well as the Energy Gateway Transmission Expansion Project. The amounts described below include amounts to which PacifiCorp is not yet firmly committed through a purchase order or other agreement.

As part of the March 2006 acquisition of PacifiCorp, MEHC and PacifiCorp made a number of commitments to the state regulatory commissions in all six states in which PacifiCorp has retail customers. These commitments are generally being implemented over several years following the acquisition and are subject to subsequent regulatory review and approval. Outstanding commitments as of December 31, 2008 include:

- Approximately $812 million in investments in emissions reduction technology for PacifiCorp's existing coal-fired generating facilities. Through December 31, 2008, PacifiCorp had spent a total of $496 million, including non-cash equity AFUDC, on these emissions reduction projects and expects to spend in excess of the original commitment due to higher commodity inflation experienced on the planned investments.
- Approximately $520 million in investments (including both capital and operating expense commitments) in PacifiCorp's transmission and distribution system that would enhance reliability, facilitate the receipt of renewable resources and enable further system optimization. Through December 31, 2008, PacifiCorp had spent a total of $224 million in capital expenditures, including non-cash equity AFUDC, in support of this commitment, and has announced the transmission expansion project discussed below.

The Energy Gateway Transmission Expansion Project is an investment plan to build approximately 2,000 miles of new high-voltage transmission lines, primarily in Wyoming, Utah, Idaho, Oregon and the desert Southwest. The plan, with an estimated cost exceeding $6.1 billion, includes projects that will address customer load growth, improve system reliability and deliver energy from new wind-powered and other renewable generating resources throughout PacifiCorp's six-state service area and the Western United States. Certain transmission segments associated with this plan are expected to be placed in service beginning in 2010, with other segments placed in service through 2018, depending on siting, permitting and construction schedules.

Transmission

PacifiCorp has agreements for the right to transmit electricity over other entities' transmission lines to facilitate delivery to PacifiCorp's customers.

Operating Leases

PacifiCorp leases offices, certain operating facilities, land and equipment under operating leases that expire at various dates through the year ending December 31, 2092. 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.

Net rent expense was $16 million and $24 million during the years ended December 31, 2008 and 2007, respectively, and $19 million during the nine-month period ended December 31, 2006.

Other

PacifiCorp has purchase obligations related to equipment maintenance and various other service and maintenance agreements.

(14) Preferred Stock

PacifiCorp's preferred stock, not subject to mandatory redemption, was as follows as of December 31 (shares in thousands, dollars in millions, except per share amounts):

	Redemption Price Per Share	2008 Shares	2008 Amount	2007 Shares	2007 Amount
Series:					
Serial Preferred, $100 stated value, 3,500 shares authorized					
4.52% to 4.72%	$102.3 to $103.5	157	$ 15	157	$ 15
5.00% to 5.40%	$100.0 to $101.0	108	10	108	10
6.00%	Non-redeemable	6	1	6	1
7.00%	Non-redeemable	18	2	18	2
5% Preferred, $100 stated value, 127 shares authorized	$110.0	126	13	126	13
		415	$ 41	415	$ 41

Generally, preferred stock is redeemable at stipulated prices plus accrued dividends, subject to certain restrictions. In the event of 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. 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.

Dividends declared but unpaid on preferred stock were $1 million as of December 31, 2008 and 2007.

(15) Common Shareholder's Equity

Through PPW Holdings LLC, MEHC is the sole shareholder of PacifiCorp's common stock. The state regulatory orders that authorized MEHC's acquisition of PacifiCorp 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 December 31, 2008, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to either 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. From January 1, 2009 through December 31, 2009 the minimum level of common equity required by this commitment is 47.25%. After December 31, 2009, 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 remaining balance of preferred stock in existence prior to MEHC's acquisition of PacifiCorp as common equity. As of December 31, 2008, PacifiCorp's actual common stock equity percentage, as calculated under this measure, was 52.6%, and PacifiCorp had $945 million available to dividend.

These commitments also restrict PacifiCorp from making any distributions to either 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 December 31, 2008, PacifiCorp's unsecured debt rating was A- by Standard & Poor's Rating Services, BBB+ by Fitch Ratings and Baa1 by Moody's Investor Service.

PacifiCorp is also subject to maximum debt-to-total capitalization percentage under various financing agreements as further discussed in Notes 8 and 9.

(16) Accumulated Other Comprehensive Loss, Net

Accumulated other comprehensive loss, net is included in shareholders' equity in the Consolidated Balance Sheets and consists of unrecognized amounts on retirement benefits of $2 million, net of tax of $2 million, and $4 million, net of tax of $2 million, as of December 31, 2008 and 2007, respectively.

(17) Variable-Interest Entities

PacifiCorp holds an undivided interest in 50% of the 474-MW Hermiston plant (refer to Note 4), procures 100% of the fuel input into the plant and subsequently receives 100% of the generated electricity, 50% of which is acquired through a long-term power purchase agreement. As a result, PacifiCorp holds a variable interest in the joint owner of the remaining 50% of the plant and is the primary beneficiary. However, upon adoption of FASB Interpretation No. 46R, *Consolidation of Variable-Interest Entities, an interpretation of Accounting Research Bulletin No. 51*, 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. Cost of the electricity purchased from the joint owner was $36 million during each of the years ended December 31, 2008 and 2007, and $26 million during the nine-month period ended December 31, 2006. 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.

(18) Related-Party Transactions

PacifiCorp has an intercompany administration services agreement with its indirect parent company, MEHC. Services provided by PacifiCorp and charged to affiliates relate primarily to administrative services, financial statement preparation and direct-assigned employees. These receivables were $1 million and $- million as of December 31, 2008 and 2007, respectively. Services provided by affiliates and charged to PacifiCorp relate primarily to the administrative services provided under the intercompany administrative services agreement among MEHC and its affiliates. These expenses totaled $9 million during each of the years ended December 31, 2008 and 2007 and $7 million during the nine-month period ended December 31, 2006. These payables were $1 million as of December 31, 2008 and 2007.

PacifiCorp engages in various transactions with several of its affiliated companies in the ordinary course of business. Services provided by affiliates in the ordinary course of business and charged to PacifiCorp relate primarily to the transportation of natural gas and relocation services. These expenses totaled $6 million and $5 million during the years ended December 31, 2008 and 2007, respectively, and $1 million during the nine-month period ended December 31, 2006. These payables were $2 million and $1 million as of December 31, 2008 and 2007, respectively.

Berkshire Hathaway, PacifiCorp's ultimate parent company, has an ownership interest in Burlington Northern Santa Fe Railway ("BNSF"). PacifiCorp has long-term transportation contracts with BNSF. Transportation costs under these contracts were $32 million and $31 million during the years ended December 31, 2008 and 2007, respectively. As of December 31, 2008 and 2007, PacifiCorp had $2 million of accounts payable to BNSF outstanding under these contracts, including indirect payables related to a jointly owned plant.

PacifiCorp participates 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, but as a result of regulatory commitments are capped through December 31, 2010. Certain costs associated with the program are prepaid and amortized over the policy coverage period expiring March 20, 2009. Premium expenses were $7 million during each of the years ended December 31, 2008 and 2007 and $6 million during the nine-month period ended December 31, 2006. Prepayments to MISL were $2 million as of December 31, 2008 and 2007. Receivables for claims were $7 million and $11 million as of December 31, 2008 and 2007, respectively.

PacifiCorp is party to a tax-sharing agreement and is part of the Berkshire Hathaway United States federal income tax return. As of December 31, 2008 and 2007, income taxes receivable from affiliates included $43 million and $23 million, respectively, of income taxes receivable from MEHC.

(19) Supplemental Cash Flows Information

The summary of supplemental cash flows information is as follows (in millions):

	Years Ended December 31, 2008	Years Ended December 31, 2007	Nine-Month Period Ended December 31, 2006
Interest paid, net of amounts capitalized	$ 280	$ 251	$ 192
Income taxes (received) paid, net	$ (53)	$ 151	$ 121
Supplemental disclosure of non-cash investing and financing activities:			
Property, plant and equipment additions in accounts payable	$ 405	$ 107	$ 79
Property, plant and equipment acquired under capital lease obligations	$ 17	$ -	$ 17

(20) Unaudited Quarterly Operating Results (in millions)

	Three-Month Periods Ended			
	March 31, 2008	June 30, 2008	September 30, 2008	December 31, 2008
Operating revenue	$ 1,095	$ 1,055	$ 1,245	$ 1,103
Operating income	230	216	269	232
Net income	108	99	132	119

	Three-Month Periods Ended			
	March 31, 2007	June 30, 2007	September 30, 2007	December 31, 2007
Operating revenue	$ 1,027	$ 1,026	$ 1,137	$ 1,068
Operating income	201	201	269	217
Net income	99	105	135	100

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A(T). CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

At the end of the period covered by this Annual Report on Form 10-K, PacifiCorp carried out an evaluation, under the supervision and with the participation of PacifiCorp's management, including the Chief Executive Officer (principal executive officer) and the Chief Financial Officer (principal financial officer), of the effectiveness of the design and operation of PacifiCorp's disclosure controls and procedures (as defined in Rule 13a-15(e) promulgated under the Securities and Exchange Act of 1934, as amended). Based upon that evaluation, PacifiCorp's management, including the Chief Executive Officer (principal executive officer) and the Chief Financial Officer (principal financial officer), concluded that PacifiCorp's disclosure controls and procedures were effective to ensure that information required to be disclosed by PacifiCorp in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and is accumulated and communicated to management, including PacifiCorp's Chief Executive Officer (principal executive officer) and Chief Financial Officer (principal financial officer), or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. There has been no change in PacifiCorp's internal control over financial reporting during the quarter ended December 31, 2008 that has materially affected, or is reasonably likely to materially affect, PacifiCorp's internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

Management of PacifiCorp is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in the Securities Exchange Act of 1934 Rule 13a-15(f). Under the supervision and with the participation of PacifiCorp's management, including the Chief Executive Officer (principal executive officer) and the Chief Financial Officer (principal financial officer), PacifiCorp's management conducted an evaluation of the effectiveness of PacifiCorp's internal control over financial reporting as of December 31, 2008 as required by the Securities Exchange Act of 1934 Rule 13a-15(c). In making this assessment, PacifiCorp's management used the criteria set forth in the framework in "Internal Control – Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the evaluation conducted under the framework in "Internal Control – Integrated Framework," PacifiCorp's management concluded that PacifiCorp's internal control over financial reporting was effective as of December 31, 2008.

This report does not include an attestation report of PacifiCorp's registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by PacifiCorp's registered public accounting firm pursuant to temporary rules of the SEC that permit PacifiCorp to provide only management's report in this Annual Report on Form 10-K.

PacifiCorp
February 20, 2009

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The Board of Directors appoints executive officers annually. There are no family relationships among the executive officers, nor any arrangements or understandings between any executive officer and any other person pursuant to which the executive officer was appointed. Set forth below is certain information, as of January 31, 2009, with respect to each of the current directors and executive officers of PacifiCorp:

Gregory E. Abel, 46, Chairman of the Board of Directors and Chief Executive Officer. Mr. Abel was elected Chief Executive Officer and Chairman of the Board of Directors in March 2006. Mr. Abel is also the President and Chief Executive Officer and a director of MEHC. Mr. Abel joined MEHC in 1992.

Douglas L. Anderson, 50, Director. Mr. Anderson has been a director since March 2006. Mr. Anderson is the Senior Vice President, General Counsel and Corporate Secretary of MEHC. Mr. Anderson joined MEHC in 1993.

Brent E. Gale, 57, Director. Mr. Gale has been a director since March 2006. Mr. Gale was appointed Senior Vice President of Regulation and Legislation of MEHC in March 2006. Mr. Gale had previously been Senior Vice President of MidAmerican Energy Company, a MEHC subsidiary, since July 2004. Mr. Gale has served in various legal, regulatory legislative and strategic positions with MEHC and its predecessors since 1976.

Patrick J. Goodman, 42, Director. Mr. Goodman has been a director since March 2006. Mr. Goodman was appointed Senior Vice President and Chief Financial Officer of MEHC in 1999. Mr. Goodman joined MEHC in 1995.

Natalie L. Hocken, 39, Director. Ms. Hocken has been a director since August 2007. Ms. Hocken has served as Vice President and General Counsel of Pacific Power, a division of PacifiCorp, since January 2007. Ms. Hocken previously served as Assistant General Counsel and Senior Counsel for PacifiCorp. Ms. Hocken joined PacifiCorp in 2002.

A. Robert Lasich, 49, President, PacifiCorp Energy and Director. Mr. Lasich was elected President of PacifiCorp Energy, a division of PacifiCorp in August 2007. Mr. Lasich joined PacifiCorp as Vice President and General Counsel, PacifiCorp Energy, and was elected director in March 2006. Mr. Lasich previously 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. Mr. Lasich joined MidAmerican Energy Company in 1997.

Mark C. Moench, 53, Director. Mr. Moench was named PacifiCorp General Counsel in February 2007. Mr. Moench joined PacifiCorp as Senior Vice President and General Counsel of Rocky Mountain Power, a division of PacifiCorp, and was elected director in March 2006. Mr. Moench previously 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.

R. Patrick Reiten, 47, President, Pacific Power and Director. Mr. Reiten was elected President of Pacific Power and director in September 2006. Mr. Reiten previously served as President and Chief Executive Officer of PNGC Power since 2002. Mr. Reiten joined PNGC Power in 1993 serving as Director of Government Relations, then as Vice President of Marketing and Public Affairs.

Douglas K. Stuver, 45, Senior Vice President and Chief Financial Officer. Mr. Stuver was elected Senior Vice President and Chief Financial Officer of PacifiCorp effective March 1, 2008. Mr. Stuver joined PacifiCorp in March 2004 as Managing Director and Division Controller of PacifiCorp’s commercial and trading business unit. In March 2006, Mr. Stuver was appointed Managing Director and Division Controller of PacifiCorp Energy, a division of PacifiCorp. Prior to joining PacifiCorp, Mr. Stuver served as Vice President of Corporate Risk Management at Duke Energy Corporation.

A. Richard Walje, 57, President, Rocky Mountain Power and Director. Mr. Walje was elected President of Rocky Mountain Power in March 2006. Mr. Walje has been a director since July 2001. Mr. Walje previously served as PacifiCorp's Executive Vice President since April 2004 and as Chief Information Officer since May 2000. Mr. Walje also served as Senior Vice President of Corporate Business Services from May 2001 to April 2004 and as Vice President for Transmission and Distribution Operations and Customer Service from 1998 to 2000. Mr. Walje has been with PacifiCorp since 1986.

Audit Committee and Audit Committee Financial Expert

During the year ended December 31, 2008, and as of the date of this Report, PacifiCorp's Board of Directors does not have an audit committee. Because PacifiCorp's common stock is indirectly, wholly owned by MEHC, its Board of Directors consists primarily of MEHC and PacifiCorp employees and it is not required to have an audit committee. However, the audit committee of MEHC acts as the audit committee for PacifiCorp.

Code of Ethics

PacifiCorp has adopted a code of ethics that applies to its principal executive officer, its principal financial and accounting officer, or persons acting in such capacities, and certain other covered officers. The code of ethics is incorporated by reference in the exhibits to this Annual Report on Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

COMPENSATION COMMITTEE REPORT

Mr. Abel, our Chairman and Chief Executive Officer and sole member of our Compensation Committee, has reviewed and discussed the Compensation Discussion and Analysis with management and, based on this review and discussion, has recommended to the Board of Directors that the Compensation Discussion and Analysis be included in this Form 10-K.

COMPENSATION DISCUSSION AND ANALYSIS

Compensation Philosophy and Overall Objectives

We and our indirect parent company, MidAmerican Energy Holdings Company, or MEHC, believe that the compensation paid to each of our Chief Executive Officer, or CEO, our Chief Financial Officer, or CFO, and our three other most highly compensated executive officers, to whom we refer collectively as our Named Executive Officers, or NEOs, should be closely aligned with our overall performance, and each NEO's contribution to that performance, on both a short- and long-term basis, and that such compensation should be sufficient to attract and retain highly qualified leaders who can create significant value for our organization. Our compensation programs are designed to provide our NEOs meaningful incentives for superior corporate and individual performance. Performance is evaluated on a subjective basis within the context of both financial and non-financial objectives that we believe contribute to our long-term success, and among which are financial strength, customer service, operational excellence, employee commitment and safety, environmental respect and regulatory integrity.

How Compensation is Determined

Our Compensation Committee consists solely of the Chairman of our Board of Directors, Mr. Gregory E. Abel. Mr. Abel also serves as our CEO and as MEHC's President and Chief Executive Officer. He is employed by MEHC and receives no direct compensation from us. Mr. Abel is responsible for the establishment and oversight of our compensation policy for our NEOs and for approving base pay increases, incentive and performance awards, off-cycle pay changes, and participation in other employee benefit plans and programs.

Our criteria for assessing executive performance and determining compensation in any year is inherently subjective and is not based upon specific formulas or weighting of factors. Given the uniqueness of each NEO's duties, we do not specifically use companies as benchmarks when establishing our NEOs' compensation.

Discussion and Analysis of Specific Compensation Elements

Base Salary

We determine base salaries for all of our NEOs, other than Mr. Abel, by reviewing our overall performance and each NEO's performance, the value each NEO brings to us and general labor market conditions. While base salary provides a base level of compensation intended to be competitive with the external market, the annual base salary adjustment for each NEO, other than Mr. Abel, is determined on a subjective basis after consideration of these factors and is not based on target percentiles or other formal criteria. An increase or decrease in base pay may also result from a promotion or other significant change in a NEO's responsibilities during the year. Annual base pay increases are approved by Mr. Abel. In 2008, base salaries for all NEOs, other than Messrs. Abel and Stuver increased on average by 2.7% and became effective December 26, 2007. On March 1, 2008, in recognition of his promotion to Senior Vice President and CFO, Mr. Stuver received a base pay increase of 12.6%. An increase or decrease in base pay may also result from a promotion or other significant change in a NEO's responsibilities during the year.

Short-Term Incentive Compensation

The objective of short-term incentive compensation is to reward the achievement of significant annual corporate and business unit goals while also providing NEOs with competitive total cash compensation.

Annual Incentive Plan

Under our Annual Incentive Plan, or AIP, all NEOs, other than Mr. Abel, are eligible to earn an annual discretionary cash incentive award, which is determined on a subjective basis and is not based on a specific formula or cap. Mr. Abel establishes a target bonus opportunity, expressed as a percentage of base salary and intended to reflect fully effective performance, for each of the other NEOs prior to the beginning of each year. Awards paid to a NEO under the AIP are based on a variety of measures linked to our overall performance and each NEO's contribution to that performance. An individual NEO's performance is measured against defined objectives that commonly include financial measures (e.g., net income and cash flow) and non-financial measures (e.g., customer service, operational excellence, employee commitment and safety, environmental respect and regulatory integrity), as well as the NEO's response to issues and opportunities that arise during the year.

Performance Awards

In addition to the annual awards under the AIP, we may grant cash performance awards periodically during the year to one or more NEOs to reward the accomplishment of significant non-recurring tasks or projects. These awards are discretionary and approved by Mr. Abel. In June 2008, Mr. Reiten received a performance award of $10,000 in recognition of efforts on PacifiCorp regulatory and legislative matters.

Long-Term Incentive Compensation

The objective of long-term incentive compensation is to retain NEOs, reward their exceptional performance and motivate them to create long-term, sustainable value. Our current long-term incentive compensation program is cash-based. Under MEHC ownership, we do not utilize equity-based compensation, such as stock option awards or equity incentive plan awards.

Long-Term Incentive Partnership Plan

The MEHC Long-Term Incentive Partnership Plan, or LTIP, is designed to retain key employees and to align our interests and the interests of the participating employees. Messrs. Walje, Reiten, Lasich and Stuver participate in the LTIP, while Mr. Abel does not. The LTIP provides for annual awards based upon significant accomplishments by the individual participants and the achievement of the financial and non-financial objectives previously described. The goals are developed with the objective of being attainable with a sustained, focused and concerted effort and are determined and communicated in January of each plan year. Participation is discretionary and is determined by Mr. Abel. Except for limited situations of extraordinary performance, awards are capped at 1.5 times base salary. The value is finalized in the first quarter of the following year. These cash-based awards are subject to mandatory deferral and equal annual vesting over a five-year period starting in the performance year. Participants allocate the value of their deferral accounts among various investment alternatives, which are determined each year by a vote of all participants. Gains or losses may be incurred based on the investment performance. After the five-year mandatory deferral and vesting period, participating NEOs may elect to defer all or part of the award or receive payment in cash into our Executive Voluntary Deferred Compensation Plan. Vested balances (including any investment profits or losses thereon) of terminating participants are paid at the time of termination.

Other Employee Benefits

Supplemental Executive Retirement Plan

The PacifiCorp Supplemental Executive Retirement Plan, or SERP, provides additional retirement benefits to participants. Mr. Walje was the only NEO who participated in our SERP during 2008, and the plan is currently closed to any new participants. The SERP provides monthly retirement benefits of 50% of final average pay plus 1% of final average pay for each fiscal year that we meet certain performance goals set for such fiscal year. The maximum benefit is 65% of final average pay. A participant's final average pay equals the 60 consecutive months of highest pay out of the last 120 months, and pay for this purpose includes salary and annual incentive plan payments reflected in the 2008 Summary Compensation Table below.

Deferred Compensation Plan

Our Executive Voluntary Deferred Compensation Plan, or DCP, provides a means for all NEOs, other than Mr. Abel, to make voluntary deferrals of up to 50% of base salary, 100% of short-term incentive compensation awards and 100% of LTIP awards following the LTIP's mandatory five-year deferral period. The deferrals and any investment returns grow on a tax-deferred basis. Amounts deferred under the DCP receive a rate of return based on the returns of any combination of eight investment options offered under the DCP and selected by the participant and the plan allows participants to choose from three forms of distribution. While the plan allows us to make discretionary contributions, we have not made contributions to date. We include the DCP as part of the participating NEO's overall compensation in order to provide a comprehensive, competitive package.

EXECUTIVE COMPENSATION

2008 Summary Compensation Table

The following table sets forth information regarding compensation earned by each of our NEOs during the years indicated:

Name and Principal Position	Year	Base Salary	Bonus [2]	Change in Pension Value and Non-Qualified Deferred Compensation Earnings [3]	All Other Compensation [4]	Total
Gregory E. Abel [1]	2008	$ -	$ -	$ -	$ -	$ -
Chairman and	2007	-	-	-	-	-
Chief Executive Officer	2006	-	-	-	-	-
A. Richard Walje	2008	345,000	328,769	267,902	10,283	951,954
President, Rocky Mountain	2007	335,811	346,582	177,128	486,302	1,345,823
Power	2006	248,108	377,106	168,501	177,982	971,697
R. Patrick Reiten	2008	258,000	353,472	11,548	24,462	647,482
President, Pacific Power	2007	250,000	330,838	3,484	2,083	586,405
	2006	-	-	-	-	-
A. Robert Lasich	2008	230,000	234,948	32,175	9,231	506,354
President, PacifiCorp Energy	2007	173,580	257,603	11,311	9,181	451,675
	2006	-	-	-	-	-
Douglas K. Stuver [5]	2008	215,499	133,140	28,928	8,817	386,384
Senior Vice President and	2007	-	-	-	-	-
Chief Financial Officer	2006	-	-	-	-	-

(1) Mr. Abel receives no direct compensation from us. We reimburse MEHC for the cost of Mr. Abel's time spent on PacifiCorp matters, including compensation paid to him by MEHC, pursuant to an intercompany administrative services agreement among MEHC and its subsidiaries. Please refer to MEHC's Annual Report on Form 10-K for the year ended December 31, 2008 (File No. 001-14881) for executive compensation information for Mr. Abel.

(2) Consists of annual cash incentive awards earned pursuant to the AIP for our NEOs, the vesting of LTIP awards and associated vested losses for Messrs. Walje, Reiten, Lasich and Stuver and amounts deferred pursuant to the DCP for Mr. Lasich. The breakout for 2008 is as follows:

		LTIP		
	AIP	Vested Award	Vested Earnings (Losses)	Change in Value [(a)]
A. Richard Walje	$ 200,000	$ 255,577	$ (126,807)	$ 128,770
R. Patrick Reiten	225,000	245,717	(117,246)	128,471
A. Robert Lasich [(b)]	190,000	168,336	(123,388)	44,948
Douglas K. Stuver	90,000	70,915	(27,775)	43,140

(a) Represents vested award plus vested earnings (losses).

(b) The AIP includes amounts deferred pursuant to the DCP of $65,000.

The ultimate payouts of LTIP awards are undeterminable as the amounts to be paid may increase or decrease depending on investment performance. Net income, the net income target goal and the matrix below were used in determining the gross amount of the LTIP award available to the group of participants, including Messrs. Walje, Reiten, Lasich and Stuver. Net income is subject to discretionary adjustment by the Chairman, CEO and Compensation Committee of MEHC. In 2008, the gross award and per-point value were adjusted to eliminate the net income benefits for the termination fee from the proposed acquisition of Constellation Energy Group, Inc., or Constellation Energy, by MEHC and the profits from MEHC's investment in Constellation Energy.

MEHC Net Income	Award Pool
Less than or equal to target goal	None
Exceeds target goal by 0.01% – 3.25%	15% of excess
Exceeds target goal by 3.251% – 6.50%	15% of the first 3.25% excess; 25% of excess over 3.25%
Exceeds target goal by more than 6.50%	15% of the first 3.25% excess; 25% of the next 3.25% excess; 35% of excess over 6.50%

A pool of up to 100,000 points in aggregate is allocated between plan participants either as initial points or year-end performance points. A nominating committee recommends the point allocation, subject to approval by the CEO and President of MEHC, based upon a discretionary evaluation of individual achievement of financial and non-financial goals previously described herein. A participant's award equals their allocated points multiplied by the final per-point value, capped at 1.5 times base salary except in extraordinary circumstances.

(3) Amounts are based upon the aggregate increase in the actuarial present value of all qualified and non-qualified defined benefit plans, which include the SERP and the Retirement Plan, as applicable. Amounts are computed using assumptions consistent with those used in preparing the applicable pension disclosures included in our Notes to Consolidated Financial Statements and are as of the pension plans' measurement dates. No participant in our DCP earned "above market or preferential" earnings on amounts deferred.

(4) Amounts shown for the year ended December 31, 2008, include:

(i) Performance award of $10,000 to Mr. Reiten.

(ii) Company contributions to our Employee Savings and Stock Ownership Plan ("401(k) Plan") of $10,283 for Mr. Walje, $8,970 for Mr. Reiten, $9,231 for Mr. Lasich and $8,817 for Mr. Stuver.

(5) Mr. Stuver was appointed Senior Vice President and Chief Financial Officer on February 19, 2008 effective March 1, 2008.

For material factors necessary to understand the information in the 2008 Summary Compensation Table, including descriptions of our AIP and the LTIP, please refer to "Compensation Discussion and Analysis" above.

2008 Pension Benefits Table

The following table sets forth certain information regarding the defined benefit pension plan accounts held (and, in Mr. Walje's case, the SERP) for each of our NEOs as of December 31, 2008:

Name	Plan Name	Number of Years of Credited Service	Present Value of Accumulated Benefits
Gregory E. Abel	N/A	-	$ -
A. Richard Walje	Retirement	22.83	630,702
	SERP	22.83	1,627,744
R. Patrick Reiten	Retirement	2.25	15,032
A. Robert Lasich	Retirement	2.75	47,424
Douglas K. Stuver	Retirement	4.75	65,117

We have adopted a non-contributory defined benefit pension plan, or the Retirement Plan, for the majority of our employees, other than employees subject to collective bargaining agreements that do not provide for coverage. Mr. Walje also participates in our non-qualified SERP. Through May 31, 2007, participants earned benefits at retirement payable for life based on length of service through May 31, 2007 and average pay in the 60 consecutive months of highest pay out of the 120 months prior to May 31, 2007, and pay for this purpose included salary and annual incentive plan payments up to 10% of base salary, but were limited to the Internal Revenue Code amounts specified in §401(a)(17). Benefits were based on 1.3% of final average pay plus 0.65% of final average pay in excess of covered compensation (as defined in Internal Revenue Code §401(1)(5)(E)) times years of service.

The Retirement Plan was restated effective June 1, 2007 to change from a traditional final-average-pay formula as described above to a cash balance formula for non-union participants. Benefits under the final-average-pay formula were frozen as of May 31, 2007, and no future benefits will accrue under that formula for non-union participants. Under the cash balance formula, benefits are based on 6.5% (5% for employees hired after June 30, 2006 and before January 1, 2008) of eligible compensation plus 4.0% of eligible compensation in excess of compensation subject to Federal Insurance Contributions Act withholding ($102,000 for 2008) to each participant's account (where such salary and incentive amounts are reduced for Internal Revenue Code §401(a)(17) limits). Interest is also credited to each participant's account. Employees who were age 40 or older as of May 31, 2007 receive certain additional transition pay credits for five years from the effective date of the plan restatement.

Participants are entitled to receive full benefits upon retirement after age 65. Participants are also entitled to receive reduced benefits upon early retirement after age 55 with at least 5 years of service or when age plus years of service equals 75.

Amounts are computed using the assumptions used in preparing the applicable pension disclosures included in Notes to Consolidated Financial Statements and are as of December 31, 2008, the plans' measurement date. Single life annuities were assumed for the SERP calculations of the present value of accumulated benefits. For the Retirement Plan calculations of the present value of accumulated benefits, the following assumptions were used: 50.0% lump sum and 50.0% single life annuity. The present value assumptions used in calculating the present value of accumulated benefits for the SERP were as follows: a discount rate of 6.90%; an expected retirement age of 60; and postretirement mortality using the RP-2000 tables. The present value assumptions used in calculating the present value of accumulated benefits for the Retirement Plan were as follows: a discount rate of 6.90%; an expected retirement age of 65; postretirement mortality using the RP-2000 tables projected to 2009; a lump sum interest rate of 6.65%; and lump sum mortality using the Internal Revenue Code §417(e)(3) Applicable Mortality Table for 2009.

The SERP provides monthly retirement benefits of 50% of final average pay plus 1% of final average pay for each fiscal year that we meet certain performance goals set for such fiscal year. The maximum benefit is 65% of final average pay. A participant's final average pay equals the 60 consecutive months of highest pay out of the last 120 months, and pay for this purpose includes salary and annual incentive plan payments reflected in the Summary Compensation Table above. Mr. Walje has met the five-year participation requirement under the plan for early retirement eligibility. Mr. Walje's SERP benefit will be reduced by a portion of his Social Security benefits, his regular retirement benefit under the Retirement Plan, and 0.25% for each month benefit commencement precedes age 60.

The above reference for the number of years of service and the present value of accumulated benefits for Mr. Lasich represents his service as a PacifiCorp employee only and does not include any vested benefits earned under MEHC.

2008 Non-Qualified Deferred Compensation Table

The following table sets forth certain information regarding the DCP accounts held by each of our NEOs as of December 31, 2008:

Name	Executive Contributions	Aggregate Earnings	Aggregate Balance at Period-End
Gregory E. Abel	$ -	$ -	$ -
A. Richard Walje	189,000	68,955	1,782,210
R. Patrick Reiten	-	-	-
A. Robert Lasich	65,000	(31,628)	118,372
Douglas K. Stuver	-	-	-

Eligibility for our DCP is restricted to select management and highly compensated employees. The plan provides tax benefits to eligible participants by allowing them to defer compensation on a pre-tax basis, thus reducing their current taxable income. Deferrals and any investment returns grow on a tax-deferred basis; thus, participants pay no income tax until they receive distributions. The DCP permits participants to make a voluntary deferral of up to 50% of base salary and 100% of short-term incentive compensation awards. All deferrals are net of social security taxes. Amounts deferred under the DCP receive a rate of return based on the returns of any combination of eight investment options offered by the plan and selected by the participant. Gains or losses are calculated monthly, and returns are posted to accounts based on participants' fund allocation elections. Participants can change their fund allocations as of the end of any calendar month.

The DCP allows participants to maintain three accounts based upon when they want to receive payments: retirement distribution, in-service distribution and education distribution. Both the retirement and in-service accounts can be distributed as lump sums or in up to 10 annual installments, except in the case of the four DCP transition accounts that allow for a grandfathered payout based on the previous deferred compensation plan distribution elections of lump sum, 5, 10 or 15 annual installments. Effective December 31, 2006, no new money may be deferred into the DCP Transition accounts. The education account is distributed in four annual installments. If a participant leaves employment prior to retirement (age 55) all amounts in the participant's account will be paid out in a lump sum as soon as administratively practicable. Participants are 100% vested in their deferrals and any investment gains or losses recorded in their accounts.

Participants in our LTIP also have the option of deferring all or a part of those awards after the five-year mandatory deferral and vesting period. The provisions governing the deferral of LTIP awards are similar to those described for the DCP above.

Potential Payments Upon Termination or Change-in-Control

Our Executive Severance Plan was closed on May 24, 2007. The plan had provided severance benefits to only legacy participants previously designated by our Compensation Committee under ScottishPower ownership.

Our NEOs (excluding Mr. Abel) are not entitled to severance or enhanced benefits upon termination of employment or change-in-control. Please refer to MEHC's Annual Report on Form 10-K for the year ended December 31, 2008 (File No. 001-14881) for information about potential post-termination and change-in-control payments to Mr. Abel. However, upon any termination of employment, our other NEOs would be entitled to the Retirement Plan and SERP vested balances presented in the Pension Benefits and the DCP balances presented in Non-Qualified Deferred Compensation Tables above.

Messrs. Walje, Reiten, Lasich and Stuver are also entitled to full vesting of outstanding awards under the MEHC LTIP in the event of death or disability. As of December 31, 2008, the value of the unvested portions of outstanding awards under this plan were $654,415 for Mr. Walje; $645,064 for Mr. Reiten; $348,944 for Mr. Lasich; and $203,733 for Mr. Stuver. In the event of termination, Messrs. Walje, Reiten, Lasich and Stuver would be entitled only to the vested benefits under this plan at the date of termination.

2008 Director Compensation Table

All of our directors serving in 2008 were employees of PacifiCorp, or in the case of Messrs. Anderson and Goodman, employees of MEHC, and did not receive additional compensation for service as a director. The following table excludes Messrs. Abel, Walje, Reiten and Lasich, for whom compensation information is described in the Summary Compensation Table.

Name	Change in Pension Value and Non-Qualified Compensation Earnings (1)	All Other Compensation (2)	Total
Douglas L. Anderson	$ -	$ -	$ -
Brent E. Gale	31,756	540,485	572,241
Patrick J. Goodman	-	-	-
Natalie L. Hocken	18,885	370,554	389,439
Mark C. Moench	32,326	357,270	389,596

(1) Amounts included in change in pension value and non-qualified deferred compensation earnings are based upon the aggregate increase in the actuarial present value of all qualified and non-qualified defined benefit plans, which include the SERP and the Retirement Plan, as applicable. Amounts are computed using assumptions consistent with those used in preparing the applicable pension disclosures included in our Notes to the Consolidated Financial Statements and are as of the pension plans' measurement dates. No participant in our Deferred Compensation Plan earned "above market or preferential" earnings on amounts deferred.

(2) Amounts shown for the year ended December 31, 2008, include:

(i) Base salary in the amounts of; $280,000 for Mr. Gale; $176,000 for Ms. Hocken; $212,382 for Mr. Moench.

(ii) Performance award of $10,000 to Mr. Gale and Ms. Hocken, respectively, in recognition of efforts on PacifiCorp regulatory and legislative matters.

(iii) Company contributions to our Employee Savings and Stock Ownership Plan of $6,967 for Mr. Gale, $3,081 for Ms. Hocken and $10,167 for Mr. Moench.

(vi) Consists of annual cash incentive awards earned pursuant to the AIP and the vested portion of awards earned (including losses on previously earned awards) pursuant to the MEHC LTIP in the amounts of:

		LTIP		
	AIP	Vested Award	Vested Earnings (Losses)	Change in Value [(a)]
Brent E. Gale	$ 155,000	$ 287,058	$ (204,032)	$ 83,026
Natalie L. Hocken	125,000	80,135	(29,153)	50,982
Mark C. Moench	100,000	200,111	(170,390)	29,721

(a) Represents vested award plus vested earnings (losses).

Compensation Committee Interlocks and Insider Participation

Mr. Abel is our Chairman of the Board of Directors and Chief Executive Officer and also the President and Chief Operating Officer of MEHC. None of our executive officers serve as a member of the compensation committee of any company that has an executive officer serving as a member of our Board of Directors. None of our executive officers serve as a member of the board of directors of any company (other than MEHC) that has an executive officer serving as a member of our compensation committee. See also Item 13 of this Form 10-K.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

All outstanding shares of our common stock are indirectly owned by MEHC, 666 Grand Avenue, Des Moines, Iowa 50309. MEHC is a consolidated subsidiary of Berkshire Hathaway that, as of January 31, 2009, owns approximately 88.25% of MEHC's common stock (87.4% on a diluted basis). The remainder of MEHC's common stock is owned by a private investor group comprised of Walter Scott, Jr. (including family members and related entities) and Gregory E. Abel, PacifiCorp's Chairman and Chief Executive Officer.

None of our executive officers or directors owns shares of our preferred stock. The following table sets forth certain information as of January 31, 2009 regarding the beneficial ownership of common stock of MEHC and the Class A and Class B common stock of Berkshire Hathaway held by each of our directors, executive officers and all of our directors and executive officers as a group as of January 31, 2009.

	MEHC Common Stock		Berkshire Hathaway Class A Common Stock		Berkshire Hathaway Class B Common Stock	
Beneficial Owner	**Number of Shares Beneficially Owned [1]**	**Percentage of Class [1]**	**Number of Shares Beneficially Owned [1]**	**Percentage of Class [1]**	**Number of Shares Beneficially Owned [1]**	**Percentage of Class [1]**
Gregory E. Abel [2][3]	749,992	1.0%	1	*	14	*
Douglas L. Anderson	-	-	4	*	4	*
Brent E. Gale	-	-	-	-	-	-
Patrick J. Goodman	-	-	2	*	3	*
Natalie L. Hocken	-	-	-	-	-	-
A. Robert Lasich	-	-	-	-	-	-
Mark C. Moench	-	-	1	*	-	-
R. Patrick Reiten	-	-	-	-	-	-
Douglas K. Stuver	-	-	-	-	-	-
A. Richard Walje	-	-	-	-	-	-
All executive officers and directors as a group (10 persons)	749,992	1.0%	8	*	21	*

* Indicates beneficial ownership of less than one percent of all outstanding shares.

(1) Includes shares of 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.

(2) In accordance with a shareholders agreement, as amended on December 7, 2005, based on an assumed value for MEHC's common stock and the closing price of Berkshire Hathaway common stock on January 31, 2009, Mr. Abel would be entitled to exchange his shares of MEHC common stock and his shares acquired by exercise of options to purchase MEHC common stock for 1,760 shares of Berkshire Hathaway Class A stock or 52,693 shares of Berkshire Hathaway Class B stock. Assuming an exchange of all available MEHC shares into either Berkshire Hathaway Class A stock or Berkshire Hathaway Class B stock, Mr. Abel would beneficially own less than 1% of the outstanding shares of either class of stock.

(3) Includes options to purchase 154,052 shares of common stock that are presently exercisable or become exercisable within 60 days.

Other Matters

Pursuant to a shareholders agreement, as amended on December 7, 2005, Mr. Abel is able to require Berkshire Hathaway to exchange any or all of his shares of MEHC common stock for shares of Berkshire Hathaway common stock. The number of shares of Berkshire Hathaway common stock to be exchanged is based on the fair market value of MEHC common stock divided by the closing price of the Berkshire Hathaway common stock on the day prior to the date of exchange.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Review, Approval or Ratification of Transactions with Related Persons

The Berkshire Hathaway Code of Business Conduct and Ethics and the MEHC Code of Business Conduct, or the Codes, which apply to all of our directors, officers and employees and those of our subsidiaries, generally govern the review, approval or ratification of any related-person transaction. A related-person transaction is one in which we or any of our subsidiaries participate and in which one or more of our directors, executive officers, holders of more than five percent of our voting securities or any of such persons' immediate family members have a direct or indirect material interest.

Under the Codes, all of our directors and executive officers (including those of our subsidiaries) must disclose to our legal department any material transaction or relationship that reasonably could be expected to give rise to a conflict with our interests. No action may be taken with respect to such transaction or relationship until approved by the legal department. For our chief executive officer and chief financial officer, prior approval for any such transaction or relationship must be given by Berkshire Hathaway's audit committee. In addition, prior legal department approval must be obtained before a director or executive officer can accept employment, offices or board positions in other for-profit businesses, or engage in his or her own business that raises a potential conflict or appearance of conflict with our interests.

Under an intercompany administrative services agreement we have entered into with MEHC and its other subsidiaries, the cost of certain administrative services provided by MEHC to us or by us to MEHC, or shared with MEHC and other subsidiaries, are directly charged or allocated to the entity receiving such services. This agreement has been filed with the utility regulatory commissions in the states where we serve retail customers. We also provide an annual report of all transactions with our affiliates to our state regulatory commissions, who have the authority to refuse recovery in retail rates for payments we make to our affiliates deemed to have the effect of subsidizing the separate business activities of MEHC or its other subsidiaries.

Refer to Note 18 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding related-party transactions.

Director Independence

Because our common stock is indirectly, wholly owned by MEHC, our Board of Directors consists primarily of MEHC and PacifiCorp employees and we are not required to have independent directors or audit, nominating or compensation committees consisting of independent directors.

Based on the standards of the New York Stock Exchange, on which the common stock of our ultimate parent company, Berkshire Hathaway is listed, our Board of Directors determined that all of our directors would not be considered independent because of their employment by MEHC or PacifiCorp.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Fees and Pre-Approval Policy

The following table shows PacifiCorp's fees paid or accrued for audit and audit-related services and fees paid for tax and all other services rendered by Deloitte & Touche LLP, the member firms of Deloitte Touche Tohmatsu, and their respective affiliates (collectively, the "Deloitte Entities") for each of the last two years (in millions):

	2008	2007
Audit fees (1)	$ 2.1	$ 2.1
Audit-related fees (2)	0.3	0.2
Tax fees (3)	-	-
All other fees	-	-
Total aggregate fees billed	$ 2.4	$ 2.3

(1) Audit fees include fees for the audit of PacifiCorp's consolidated financial statements and interim reviews of PacifiCorp's quarterly financial statements, audit services provided in connection with required statutory audits, and comfort letters, consents and other services related to SEC matters.

(2) Audit-related fees primarily include fees for assurance and related services for any other statutory or regulatory requirements, audits of certain employee benefit plans and consultations on various accounting and reporting matters.

(3) Tax fees include fees for services relating to tax compliance, tax planning and tax advice. These services include assistance regarding federal and state tax compliance, tax return preparation and tax audits.

The audit committee of MEHC reviewed and approved the services rendered by the Deloitte Entities in and for fiscal 2008 as set forth in the above table and concluded that the non-audit services were compatible with maintaining the principal accountant's independence. Under the Sarbanes-Oxley Act of 2002, all audit and non-audit services performed by the principal accountant require approval in advance by the audit committee in order to assure that such services do not impair the principal accountant's independence from PacifiCorp. Accordingly, the audit committee has an Audit and Non-Audit Services Pre-Approval Policy (the "Policy") that sets forth the procedures and the conditions pursuant to which services to be performed by the principal 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. If not pre-approved on an annual basis, proposed services must otherwise be separately approved prior to being performed by the principal 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 Policy does not delegate to management the audit committee's responsibilities to pre-approve services performed by the principal accountant.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Financial Statements and Schedules

(i). Financial Statements:
Financial statements are included in Item 8.

(ii) Financial Statement Schedules:
All schedules have been omitted because they are either not applicable, not required or the information required to be set forth therein is included in the Consolidated Financial Statements or notes thereto.

(b) Exhibits
The exhibits listed on the accompanying Exhibit Index are filed as part of this Annual Report.

(c) Financial statements required by Regulation S-X, which are excluded from the Annual Report by Rule 14a-3(b).

Not applicable.

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 on this 27th day of February 2009.

PACIFICORP

/s/ Douglas K. Stuver
Douglas K. Stuver
Senior Vice President and Chief Financial Officer
(principal financial and accounting 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.

Signature	Title	Date
/s/ Gregory E. Abel Gregory E. Abel	Chairman of the Board of Directors and Chief Executive Officer (principal executive officer)	February 27, 2009
/s/ Douglas K. Stuver Douglas K. Stuver	Senior Vice President and Chief Financial Officer (principal financial and accounting officer)	February 27, 2009
/s/ Douglas L. Anderson Douglas L. Anderson	Director	February 27, 2009
/s/ Brent E. Gale Brent E. Gale	Director	February 27, 2009
/s/ Patrick J. Goodman Patrick J. Goodman	Director	February 27, 2009
/s/ Natalie L. Hocken Natalie L. Hocken	Director	February 27, 2009
/s/ A. Robert Lasich A. Robert Lasich	Director	February 27, 2009
/s/ Mark C. Moench Mark C. Moench	Director	February 27, 2009
/s/ R. Patrick Reiten R. Patrick Reiten	Director	February 27, 2009
/s/ A. Richard Walje A. Richard Walje	Director	February 27, 2009

EXHIBIT INDEX

Exhibit No. **Description**

3.1* Third Restated Articles of Incorporation of PacifiCorp (Exhibit (3)b, Annual Report on Form 10-K for the year ended December 31, 1996, filed March 21, 1997, File No. 1-5152).

3.2* Bylaws of PacifiCorp, as amended May 23, 2005 (Exhibit 3.2, on Annual Report on Form 10-K for the year ended March 31, 2006, filed May 30, 2006, File No. 1-5152).

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 23 Supplemental Indentures as follows:

Exhibit No.	File Type	File Date	File Number
(4)(b)	SE	November 2, 1989	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	8-K	August 14, 2006	1-5152
4	8-K	March 14, 2007	1-5152
4.1	8-K	October 3, 2007	1-5152
4.1	8-K	July 17, 2008	1-5152
4.1	8-K	January 8, 2009	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% 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 Summary of Key Terms of Named Executive Officer and Employee Director Compensation.

10.2* PacifiCorp Executive Voluntary Deferred Compensation Plan (Exhibit 10.3, Annual Report on Form 10-K, for the year ended December 31, 2007, filed February 29, 2008, File No. 1-5152).

10.3* Supplemental Executive Retirement Plan (Exhibit 10.7, Annual Report on Form 10-K, for the year ended March 31, 2005, filed May 27, 2005, File No. 1-5152).

10.4* Amendment No. 10 to PacifiCorp Supplemental Executive Retirement Plan dated June 2, 2006 (Exhibit 10.5, Quarterly Report on Form 10-Q, filed August 7, 2006, File No. 1-5152).

10.5* Amendment No. 11 to PacifiCorp Supplemental Executive Retirement Plan dated June 2, 2006 (Exhibit 10.6, Quarterly Report on Form 10-Q, filed August 7, 2006, File No. 1-5152).

10.6* $700,000,000 Credit Agreement dated as of October 23, 2007 among PacifiCorp, The Banks Party thereto, The Royal Bank of Scotland plc, as Syndication Agent, and Union Bank of California, N.A., as Administrative Agent. (Exhibit 99, Quarterly Report on Form 10-Q, filed November 2, 2007, File No. 1-5152).

10.7* $800,000,000 Amended and Restated Credit Agreement dated as of July 6, 2006 among PacifiCorp, The Banks Party Hereto, JPMorgan Chase Bank, N.A., as Administrative Agent and Issuing Bank, and The Royal Bank of Scotland plc, as Syndication Agent. (Exhibit 99, Quarterly Report on Form 10-Q, filed August 4, 2006, File No. 1-5152).

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 Preference Dividends.

14.1* Code of Ethics (Exhibit 14.1, Transition Report on Form 10-K for the nine-month period ended December 31, 2006, filed March 2, 2007, File No. 1-5152).

23.1 Consent of Deloitte & Touche LLP.

31.1 Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1 Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2 Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

*Incorporated herein by reference.