PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

825 NE Multnomah, Suite1900
Portland, Oregon 97232-2135

UTAH PUBLIC
SERVICE COMMISSION

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March 16, 2012

Public Service Commission of Utah
160 East 300 South
P.O. Box 45585
Salt Lake City, UT 84145-0585

Dear Commission:

Docket No. 12-999-01

Enclosed is a copy of PacifiCorp's most recent quarterly report on Form 10-K for the period ended December 31, 2011, as filed with the Securities and Exchange Commission pursuant to the requirement of the Securities Exchange Act of 1934.

Very Truly Yours,

Ryan Weems
External Reporting Manager

Enclosure

**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, 2011
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**<br>**(An Oregon Corporation)**<br>**825 N.E. Multnomah Street**<br>**Portland, Oregon 97232**<br>**503-813-5608** | **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 whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). 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 the 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 ☒

All shares of outstanding common stock of PacifiCorp are indirectly owned by MidAmerican Energy Holdings Company, 666 Grand Avenue, Des Moines, Iowa 50309. As of January 31, 2012, 357,060,915 shares of common stock were outstanding.

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**Definition of Abbreviations and Industry Terms**

When used in Part I, Items 1 through 4, and Part II, Items 5 through 7A and Items 9, 9A and 9B, the following terms have the definitions indicated.

| | |
|---|---|
| **PacifiCorp and Related Entities** | |
| MEHC | MidAmerican Energy Holdings Company |
| PacifiCorp | PacifiCorp and its subsidiaries |
| PPW Holdings | PPW Holdings LLC, a wholly owned subsidiary of MEHC and PacifiCorp's direct parent company |
| PMI | Pacific Minerals, Inc. |
| Fossil Rock | Fossil Rock Fuels, LLC |
| Bridger Coal | Bridger Coal Company |
| Berkshire Hathaway | Berkshire Hathaway Inc. and its subsidiaries |
| **Certain Industry Terms** | |
| AFUDC | Allowance for Funds Used During Construction |
| CPUC | California Public Utilities Commission |
| DSM | Demand-side Management |
| EBA | Energy Balancing Account |
| ECAC | Energy Cost Adjustment Clause |
| ECAM | Energy Cost Adjustment Mechanism |
| EPA | United States Environmental Protection Agency |
| FERC | Federal Energy Regulatory Commission |
| GHG | Greenhouse Gases |
| GHG Reporting | Greenhouse Gases Reporting |
| GWh | Gigawatt hour |
| IPUC | Idaho Public Utilities Commission |
| IRP | Integrated Resource Plan |
| kV | Kilovolt |
| Mine Safety Act | Federal Mine Safety and Health Act of 1977 |
| MSHA | Federal Mine Safety and Health Administration |
| MW | Megawatts |
| MWh | Megawatt hour |
| NERC | North American Electric Reliability Corporation |
| OPUC | Oregon Public Utility Commission |
| PCAM | Power Cost Adjustment Mechanism |
| PTAM | Post Test-year Adjustment Mechanism |
| RAC | Renewable Adjustment Clause |
| RCRA | Resource Conservation and Recovery Act |
| REC | Renewable Energy Credit |
| RFPs | Requests for Proposals |
| RPS | Renewable Portfolio Standards |
| SEC | United States Securities and Exchange Commission |
| SIP | State Implementation Plan |
| TAM | Transition Adjustment Mechanism |
| UPSC | Utah Public Service Commission |
| WECC | Western Electricity Coordinating Council |
| WPSC | Wyoming Public Service Commission |
| WUTC | Washington Utilities and Transportation Commission |

**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 Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements can typically be identified by the use of forward-looking words, such as "will," "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 the control of PacifiCorp and could cause actual results to differ materially from those expressed or implied by such forward-looking statements. These factors include, among others:

- general economic, political and business conditions, as well as changes in laws and regulations affecting PacifiCorp's operations or related industries;

- changes in, and compliance with, environmental laws, regulations, decisions and policies that could, among other items, increase operating and capital costs, reduce generating facility output, accelerate generating facility retirements or delay generating facility construction or acquisition;

- the outcome of general rate cases and other proceedings conducted by regulatory commissions or other governmental and legal bodies and PacifiCorp's ability to recover costs in rates in a timely manner;

- changes in economic, industry or weather conditions, as well as demographic trends, that could affect customer growth and usage, electricity supply or PacifiCorp's ability to obtain long-term contracts with customers and suppliers;

- a high degree of variance between actual and forecasted load that could impact PacifiCorp's hedging strategy and the cost of balancing its generation resources and wholesale activities with its retail load obligations;

- performance and availability of PacifiCorp's generating facilities, including the impacts of outages and repairs, transmission constraints, weather and operating conditions;

- hydroelectric conditions, as well as the cost, feasibility and eventual outcome of hydroelectric relicensing proceedings, that could have a significant impact on electricity capacity and cost and PacifiCorp's ability to generate electricity;

- changes in prices, availability and demand for both purchases and sales of wholesale electricity, coal, natural gas, other fuel sources and fuel transportation that could have a significant impact on generating 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 reductions in demand for investment-grade commercial paper, debt securities and other sources of debt financing and volatility in the London Interbank Offered Rate, the base interest rate for PacifiCorp's credit facilities;

- changes in PacifiCorp's credit ratings;

- the impact of derivative contracts used to mitigate or manage volume, price and interest rate risk, including increased collateral requirements, and changes in commodity prices, interest rates and other conditions that affect the fair value of derivative contracts;

- the impact of inflation on costs and our ability to recover such costs in rates;

- increases in employee healthcare costs;

- the impact of investment performance and changes in interest rates, legislation, healthcare cost trends, mortality and morbidity on PacifiCorp's pension and other postretirement benefits expense and funding requirements and the multiemployer plans to which PacifiCorp contributes;

- 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 guidance or changes in current accounting estimates and assumptions on PacifiCorp's consolidated financial results;

- other risks or unforeseen events, including the effects of storms, floods, litigation, wars, terrorism, embargoes and other catastrophic events; and

- other business or investment considerations that may be disclosed from time to time in PacifiCorp's filings with the SEC or in other publicly disseminated written documents.

Further details of the potential risks and uncertainties affecting PacifiCorp are described in 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 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, vertically integrated 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, 75 thermal, hydroelectric, wind-powered and geothermal generating facilities, with a net owned capacity of 10,597 MW. PacifiCorp also owns, or has interests in, electric transmission and distribution assets, and transmits electricity through approximately 16,200 miles of transmission lines. PacifiCorp also buys and sells electricity on the wholesale market with other utilities, energy marketing companies, financial institutions and other market participants 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 and environmental remediation services. PacifiCorp is an indirect subsidiary of MEHC, a holding company based in Des Moines, Iowa, that owns subsidiaries principally engaged in energy businesses. MEHC is a consolidated subsidiary of Berkshire Hathaway. MEHC controls substantially all of PacifiCorp's voting securities, which include both common and preferred stock.

PacifiCorp's principal executive offices are located at 825 N.E. Multnomah Street, Portland, Oregon 97232, and its telephone number is (503) 813-5608. PacifiCorp was initially incorporated in 1910 under the laws of the state of Maine under the name Pacific Power & Light Company. In 1984, Pacific Power & Light Company changed its name to PacifiCorp. In 1989, it merged with Utah Power and Light Company, a Utah corporation, in a transaction wherein both corporations merged into a newly formed Oregon corporation. The resulting Oregon corporation was re-named PacifiCorp, which is the operating entity today.

#### Berkshire Hathaway Equity Commitment

Pursuant to an Equity Commitment Agreement (the "Berkshire Equity Commitment") among MEHC and Berkshire Hathaway amended as of March 1, 2011, Berkshire Hathaway has agreed to purchase up to $2.0 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 (a) paying when due MEHC's debt obligations and (b) 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, 2014.

#### 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 trading, and coal mining functions are operated under the trade name PacifiCorp Energy. PacifiCorp owns or has contracts for fuel sources, such as coal and natural gas, and uses these fuel sources, as well as water, wind and geothermal 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 ratemaking purposes and that it will be allowed an opportunity to earn a reasonable return on its investments.

PacifiCorp seeks to manage growth in its customer demand through the construction and purchase of cost-effective, environmentally prudent and efficient sources of power supply and through demand response and energy efficiency programs. During 2011, PacifiCorp began construction of the 637-MW Lake Side 2 combined-cycle combustion turbine natural gas-fueled generating facility ("Lake Side 2"), which is expected to be placed in service in 2014, to help meet future retail load growth and replace supply provided by wholesale contracts that are expiring or for which the level of supply has been reduced.

**Employees**

As of December 31, 2011, PacifiCorp, together with its subsidiaries, had approximately 6,400 employees, of which approximately 3,800 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.

**Retail Service Territories**

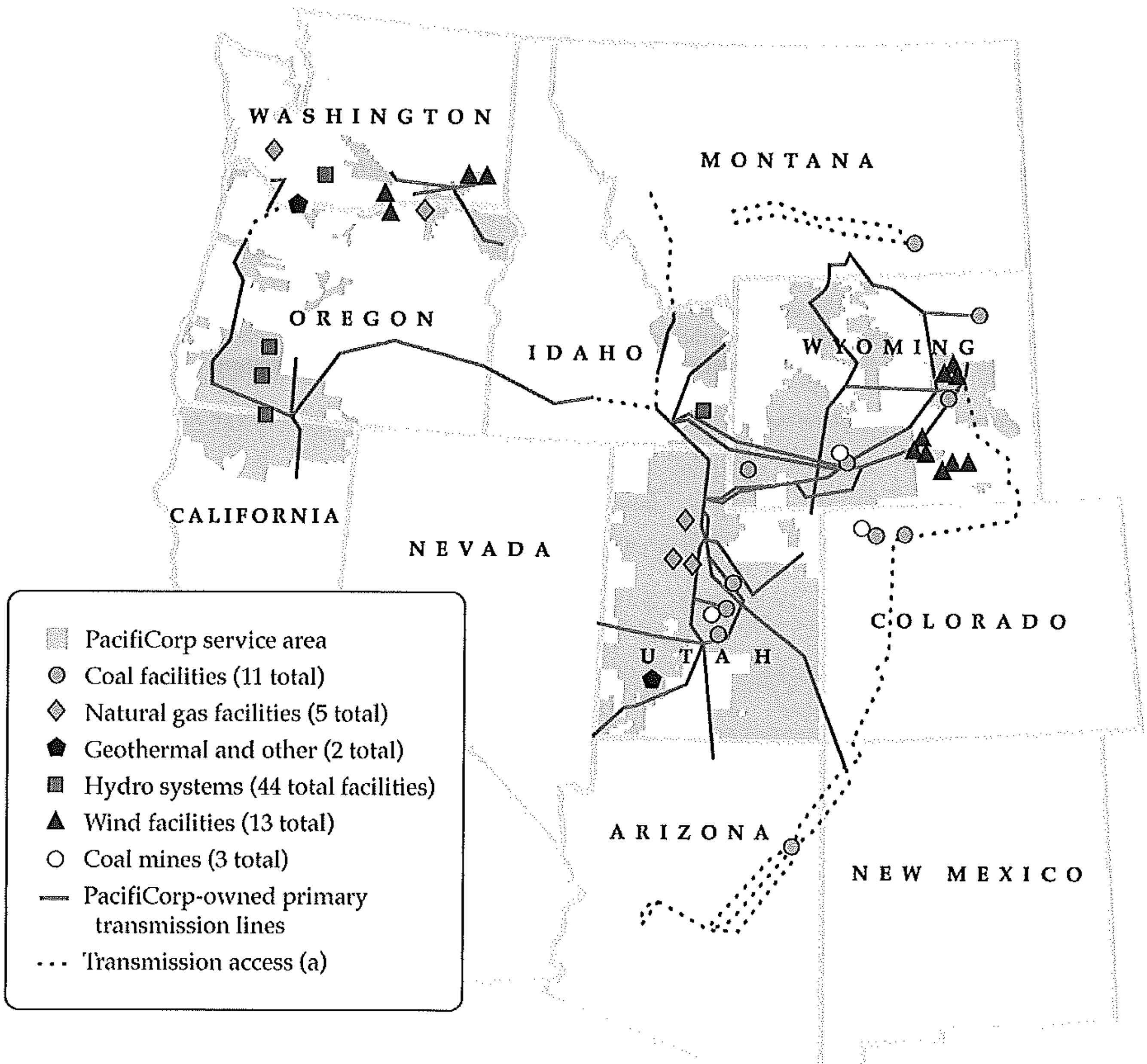
PacifiCorp's combined service territory covers approximately 136,000 square miles and includes diverse regional economies ranging from rural, agricultural and mining areas to urban, manufacturing and government service centers. No single segment of the economy dominates the service territory, which helps mitigate PacifiCorp's exposure to economic fluctuations. In the eastern portion of the service territory, consisting of Utah, Wyoming and southeastern Idaho, the principal industries are manufacturing, mining or extraction of natural resources, agriculture, technology and recreation. In the western portion of the service territory, consisting of Oregon, southern Washington and northern California, the principal industries are agriculture, manufacturing, forest products, food processing, technology and primary metals.

PacifiCorp's operations are conducted under numerous franchise agreements, certificates, permits and licenses obtained from federal, state and local authorities. The average term of the franchise agreements is approximately 30 years, although their terms range from five years to indefinite. Several of these franchise agreements allow the municipality the right to seek amendment to the franchise agreement at a specified time during the term. PacifiCorp generally has an exclusive right to serve electric customers within its service territories and, in turn, has an obligation to provide electric service to those customers.

The GWh and percentages of electricity sold to retail customers by jurisdiction were as follows for the years ended December 31:

| | 2011 | | 2010 | | 2009 | |
|---|---|---|---|---|---|---|
| Utah | 23,245 | 43 % | 22,477 | 42 % | 22,098 | 42 % |
| Oregon | 13,014 | 24 | 12,717 | 24 | 13,422 | 25 |
| Wyoming | 9,793 | 18 | 9,680 | 18 | 9,202 | 17 |
| Washington | 4,006 | 7 | 3,985 | 8 | 4,184 | 8 |
| Idaho | 3,440 | 6 | 3,326 | 6 | 2,956 | 6 |
| California | 809 | 2 | 831 | 2 | 848 | 2 |
| | 54,307 | 100 % | 53,016 | 100 % | 52,710 | 100 % |

The following map highlights PacifiCorp's retail service territories, generating facility locations, coal mines in which PacifiCorp has an interest and PacifiCorp's primary transmission lines as of December 31, 2011. 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.

## Customers

Electricity sold to retail and wholesale customers by class of customer, total GWh sold and the average number of retail customers for the years ended December 31 were as follows:

| | 2011 | | 2010 | | 2009 | |
|---|---|---|---|---|---|---|
| GWh sold: | | | | | | |
| Residential | 16,046 | 25% | 15,795 | 24% | 15,999 | 24% |
| Commercial | 16,489 | 25 | 15,969 | 25 | 16,194 | 25 |
| Industrial | 21,229 | 32 | 20,680 | 32 | 19,934 | 31 |
| Other | 543 | 1 | 572 | 1 | 583 | 1 |
| Total retail | 54,307 | 83 | 53,016 | 82 | 52,710 | 81 |
| Wholesale | 10,767 | 17 | 11,415 | 18 | 12,349 | 19 |
| Total GWh sold | 65,074 | 100% | 64,431 | 100% | 65,059 | 100% |
| Average number of retail customers (in thousands): | | | | | | |
| Residential | 1,483 | 85% | 1,475 | 85% | 1,467 | 85% |
| Commercial | 221 | 13 | 220 | 13 | 214 | 13 |
| Industrial | 34 | 2 | 34 | 2 | 34 | 2 |
| Other | 4 | — | 4 | — | 4 | — |
| Total | 1,742 | 100% | 1,733 | 100% | 1,719 | 100% |
| Retail customers: | | | | | | |
| Average usage per customer (kilowatt hours) | 31,175 | | 30,595 | | 30,672 | |
| Average revenue per customer | $ 2,331 | | $ 2,142 | | $ 2,076 | |
| Revenue per kilowatt hour | 7.5¢ | | 7.0¢ | | 6.8¢ | |

## Customer Usage and Seasonality

In addition to the variations in weather from year to year, fluctuations in economic conditions within PacifiCorp's service territory and elsewhere impact customer usage, particularly for industrial and wholesale customers. Beginning in the fourth quarter of 2008 and continuing into 2009, certain customer usage levels declined due to the effects of the economic conditions in the United States. The declining usage trend reversed during 2010 in the eastern side of PacifiCorp's service territory although partially offset by unfavorable weather conditions. The declining usage trend continued during 2010 in the western side of PacifiCorp's service territory. During 2011, PacifiCorp's customer usage levels increased in the eastern service territory primarily due to improving economic conditions and increased in the western service territory mainly due to weather impacts.

The annual hourly peak customer demand, which represents the highest demand on a given day and at a given hour, is typically highest in the summer across PacifiCorp's service territory when air conditioning and irrigation systems are heavily used. The service territory also has a winter peak, which is primarily due to heating requirements in the western portion of PacifiCorp's service territory. During 2011, PacifiCorp's peak demand was 9,431 MW in the summer and 8,786 MW in the winter.

### Generating Facilities and Fuel Supply

PacifiCorp is required to have resources available to continuously meet its customer needs. The percentage of PacifiCorp's energy supplied by energy source varies from year to year and is subject to numerous operational and economic factors such as planned and unplanned outages; fuel commodity prices; fuel transportation costs; weather; environmental considerations; transmission constraints; and wholesale market prices of electricity. PacifiCorp evaluates these factors continuously in order to facilitate economical dispatch of its generating facilities. When factors for one energy source are less favorable, PacifiCorp must place more reliance on other energy sources. For example, PacifiCorp can generate more electricity using its low cost hydroelectric and wind-powered generating facilities when factors associated with these facilities are favorable. When factors associated with hydroelectric and wind resources are less favorable, PacifiCorp increases its reliance on coal- and natural gas-fueled generation or purchased electricity. In addition to meeting its customers' energy needs, PacifiCorp is required to maintain operating reserves on its system to mitigate unplanned outages or other disruption in supply, and to meet intra-hour changes in load and resource balance. This operating reserve requirement is dispersed across PacifiCorp's generation portfolio on a least-cost basis based on the operating characteristics of the portfolio. Operating reserves may be held on hydroelectric, coal-fueled or natural gas-fueled resources. PacifiCorp manages certain risks relating to its supply of electricity and fuel requirements by entering into various contracts, which may be accounted for as derivatives, including forwards, futures, options, swaps and other agreements. Refer to Item 7A in this Form 10-K for a discussion of commodity price risk and derivative contracts.

PacifiCorp has ownership interest in a diverse portfolio of generating facilities. The following table presents certain information regarding PacifiCorp's owned generating facilities as of December 31, 2011:

| | Location | Energy Source | Installed | Facility Net Capacity (MW)(1) | Net Owned Capacity (MW)(1) |
|---|---|---|---|---|---|
| COAL: | | | | | |
| Jim Bridger | Rock Springs, WY | Coal | 1974-1979 | 2,118 | 1,412 |
| Hunter Nos. 1, 2 and 3 | Castle Dale, UT | Coal | 1978-1983 | 1,352 | 1,147 |
| Huntington | Huntington, UT | Coal | 1974-1977 | 909 | 909 |
| 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 | 395 | 395 |
| Wyodak | Gillette, WY | Coal | 1978 | 335 | 268 |
| Carbon | Castle Gate, UT | Coal | 1954-1957 | 172 | 172 |
| Craig Nos. 1 and 2 | Craig, CO | Coal | 1979-1980 | 863 | 166 |
| Colstrip Nos. 3 and 4 | Colstrip, MT | Coal | 1984-1986 | 1,480 | 148 |
| Hayden Nos. 1 and 2 | Hayden, CO | Coal | 1965-1976 | 446 | 78 |
| | | | | 9,532 | 6,157 |
| NATURAL GAS: | | | | | |
| Lake Side | Vineyard, UT | Natural gas/steam | 2007 | 558 | 558 |
| Currant Creek | Mona, UT | Natural gas/steam | 2005-2006 | 550 | 550 |
| Chehalis | Chehalis, WA | Natural gas/steam | 2003 | 520 | 520 |
| Hermiston | Hermiston, OR | Natural gas/steam | 1996 | 474 | 237 |
| Gadsby Steam | Salt Lake City, UT | Natural gas | 1951-1955 | 231 | 231 |
| Gadsby Peakers | Salt Lake City, UT | Natural gas | 2002 | 120 | 120 |
| | | | | 2,453 | 2,216 |
| HYDROELECTRIC: (2) | | | | | |
| Lewis River System (3) | WA | Hydroelectric | 1931-1958 | 578 | 578 |
| North Umpqua River System (4) | OR | Hydroelectric | 1950-1956 | 204 | 204 |
| Klamath River System (5) | CA, OR | Hydroelectric | 1903-1962 | 170 | 170 |
| Bear River System (6) | ID, UT | Hydroelectric | 1908-1984 | 105 | 105 |
| Rogue River System (7) | OR | Hydroelectric | 1912-1957 | 52 | 52 |
| Minor hydroelectric facilities | Various | Hydroelectric | 1895-1986 | 36 | 36 |
| | | | | 1,145 | 1,145 |
| WIND: (2) | | | | | |
| Marengo | Dayton, WA | Wind | 2007 | 140 | 140 |
| Dunlap Ranch I | Medicine Bow, WY | Wind | 2010 | 111 | 111 |
| Leaning Juniper I | Arlington, OR | Wind | 2006 | 101 | 101 |
| High Plains | McFadden, WY | Wind | 2009 | 99 | 99 |
| Rolling Hills | Glenrock, WY | Wind | 2009 | 99 | 99 |
| 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 | Arlington, WY | Wind | 1999 | 41 | 32 |
| Glenrock III | Glenrock, WY | Wind | 2009 | 39 | 39 |
| McFadden Ridge I | McFadden, WY | Wind | 2009 | 28 | 28 |
| Seven Mile Hill II | Medicine Bow, WY | Wind | 2008 | 20 | 20 |
| | | | | 1,040 | 1,031 |
| GEOTHERMAL AND OTHER: (2) | | | | | |
| Blundell | Milford, UT | Geothermal | 1984, 2007 | 34 | 34 |
| Camas Co-Gen | Camas, WA | Black liquor | 1996 | 14 | 14 |
| | | | | 48 | 48 |
| Total available generating capacity | | | | 14,218 | 10,597 |
| PROJECTS UNDER CONSTRUCTION: (8) | | | | | |
| Lake Side 2 | Vineyard, UT | Natural gas/steam | | 637 | 637 |
| | | | | 14,855 | 11,234 |

(1) Facility net capacity represents (except for wind-powered generating facilities, which are nominal ratings) 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. A wind turbine generator's nominal rating is the manufacturer's contractually specified capability (in MW) under specified conditions. Net owned capacity indicates PacifiCorp's ownership of facility net capacity.

(2) All or some of the renewable energy attributes associated with generation from these generating facilities may be: (a) used in future years to comply with RPS or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

(3) The license for these facilities is valid through May 2058.

(4) The license for these facilities is valid through October 2038.

(5) The license for these facilities was valid through February 2006, and they currently operate under 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 hydroelectric system.

(6) The license is valid through March 2024 for Cutler and through November 2033 for the Grace, Oneida and Soda hydroelectric generating facilities.

(7) 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.

(8) Facility Net Capacity and Net Owned Capacity for projects under construction each represent the estimated rating.

The following table shows the percentages of PacifiCorp's total energy supplied by energy source for the years ended December 31:

| | 2011 | 2010 | 2009 |
|---|---|---|---|
| Coal | 59 % | 62 % | 63 % |
| Natural gas | 9 | 12 | 12 |
| Hydroelectric | 7 | 5 | 5 |
| Other | 5 | 5 | 4 |
| Total energy generated | 80 | 84 | 84 |
| Energy purchased - short-term contracts and other | 12 | 8 | 10 |
| Energy purchased - long-term contracts | 8 | 8 | 6 |
| | 100 % | 100 % | 100 % |

*Coal*

PacifiCorp has interests in coal mines that support its coal-fueled generating facilities and operates the Deer Creek, Bridger surface and Bridger underground coal mines. These mines supplied 28%, 29% and 31% of PacifiCorp's total coal requirements during the years ended December 31, 2011, 2010 and 2009, respectively. The remaining coal requirements are acquired through long- and short-term third-party contracts. PacifiCorp also operates the Cottonwood Preparatory Plant and Wyodak Coal Crushing Facility. PacifiCorp's mines are located adjacent to certain of its coal-fueled generating facilities, which significantly reduces overall transportation costs. 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.

Coal reserve estimates are subject to adjustment as a result of the development of additional engineering and geological data, new mining technology and changes in regulation and economic factors affecting the utilization of such reserves. Recoverable coal reserves of operating mines as of December 31, 2011, based on PacifiCorp's most recent engineering studies, were as follows (in millions):

| Coal Mine | Location | Generating Facility Served | Mining Method | Recoverable Tons | |
|---|---|---|---|---|---|
| Bridger | Rock Springs, WY | Jim Bridger | Surface | 41 | (1) |
| Bridger | Rock Springs, WY | Jim Bridger | Underground | 39 | (1) |
| Deer Creek | Huntington, UT | Huntington, Hunter and Carbon | Underground | 27 | (2) |
| Trapper | Craig, CO | Craig | Surface | 45 | (3) |
| | | | | 152 | |

(1) These coal reserves are leased and mined by Bridger Coal, a joint venture between 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 amounts included above represent only PacifiCorp's two-thirds interest in the coal reserves.

(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 Trapper Mining Inc., a cooperative, in which PacifiCorp has an ownership interest of 21%. The amount included above represents only PacifiCorp's 21% interest in the coal reserves. PacifiCorp does not operate the Trapper mine.

For surface mine operations, PacifiCorp removes the overburden with heavy earth-moving equipment, such as draglines and power shovels. Once exposed, PacifiCorp drills, fractures and systematically removes the coal using haul trucks or conveyors to transport the coal to the associated generating facility. PacifiCorp reclaims disturbed areas as part of its normal mining activities. After final coal removal, draglines, power shovels, excavators or loaders are used to backfill the remaining pits with the overburden removed at the beginning of the process. Once the overburden and topsoil have been replaced, vegetation and plant life are re-established, and other improvements are made that have local community and environmental benefits. Draglines are used at the Bridger surface mine and draglines with shovels and trucks are used at the Trapper surface mine.

For underground mine operations, a longwall is used as a mechanical shearer to extract coal from long rectangular blocks of medium to thick seams. In longwall mining, PacifiCorp also uses continuous miners to develop access to these long rectangular coal blocks. Hydraulically powered supports temporarily hold up the roof of the mine while a rotating drum mechanically advances across the face of the coal seam, cutting the coal from the face. Chain conveyors then move the loosened coal to an underground mine conveyor system for delivery to the surface. Once coal is extracted from an area, the roof is allowed to collapse in a controlled fashion.

In June 2011, Fossil Rock, a wholly owned subsidiary of PacifiCorp, acquired the Cottonwood coal reserve lease in Emery County Utah. PacifiCorp intends to mine the Cottonwood coal reserves in the future and has estimated the recoverable tons to be 47 million.

Recoverability by surface mining methods typically ranges from 90% to 95%. Recoverability by underground mining techniques ranges from 50% to 70%. To meet applicable standards, PacifiCorp blends coal mined at its owned mines with contracted coal and utilizes emissions reduction technologies for controlling sulfur dioxide and other emissions. For fuel needs at PacifiCorp's coal-fueled generating facilities in excess of coal reserves available, PacifiCorp believes it will be able to purchase coal under both long- and short-term contracts to supply its generating facilities over their currently expected remaining useful lives.

During the year ended December 31, 2011, PacifiCorp-owned coal-fueled generating facilities held sufficient sulfur dioxide emission allowances to comply with the EPA Title IV requirements. For a further discussion regarding EPA requirements and other environmental laws and regulations, refer to "Environmental Laws and Regulations" in Item 7 of this Form 10-K.

*Natural Gas*

PacifiCorp uses natural gas as fuel for its combined- and simple-cycle natural gas-fueled generating facilities. Oil and natural gas are also used for igniter fuel and to fuel generation for transmission support and standby purposes. These sources are presently in adequate supply and available to meet PacifiCorp's needs.

PacifiCorp enters into forward natural gas purchases generally at floating market prices for physical delivery to its natural gas-fueled generating facilities. PacifiCorp purchases natural gas in the spot market generally at fixed market prices for physical delivery to fulfill any fuel requirements not already satisfied through forward purchases of natural gas and sells natural gas in the spot market for the disposition of any excess supply if the forecasted requirements of its natural gas-fueled generating facilities decrease. PacifiCorp also utilizes financial swap contracts to mitigate price risk associated with its forecasted fuel requirements.

*Hydroelectric*

The amount of electricity PacifiCorp is able to generate from its hydroelectric facilities depends on a number of factors, including snowpack 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.

PacifiCorp operates the majority of its hydroelectric generating portfolio under long-term licenses. The FERC regulates 98% of the net capacity of this portfolio through 15 individual licenses, which have terms of 30 to 50 years, while a portion of the portfolio is licensed under the Oregon Hydroelectric Act. For further discussion of PacifiCorp's hydroelectric relicensing and decommissioning activities, including updated information regarding the Klamath River hydroelectric system, refer to "Hydroelectric Relicensing" and "Hydroelectric Decommissioning" below and Note 13 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

*Wind and Other Renewable Resources*

PacifiCorp has pursued additional renewable resources as a viable, economical and environmentally prudent means of supplying electricity. Renewable resources have low to no emissions, require little or no fossil fuel and are complemented by PacifiCorp's other generating facilities and wholesale transactions. Wind-powered generating facilities placed in service by December 31, 2012 are eligible for federal renewable electricity production tax credits for 10 years from the date the facilities are placed in service.

*Wholesale Activities*

PacifiCorp purchases and sells electricity in the wholesale markets as needed to balance its generation and long-term purchase commitments with its retail load and long-term wholesale sales obligations. PacifiCorp may also purchase electricity in the wholesale markets when it is more economical than generating electricity from its own facilities. When prudent, PacifiCorp enters into financial swap contracts and forward electricity sales and purchases for physical delivery at fixed prices to reduce its exposure to electricity price volatility.

**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 transmission 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 electricity 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.

PacifiCorp's transmission system is part of the Western Interconnection, the regional grid in the Western United States. The Western Interconnection includes the interconnected transmission systems of 14 western states, two Canadian provinces and parts of Mexico. The map under "Service Territories" above shows PacifiCorp's primary transmission system.

As of December 31, 2011, PacifiCorp owned, or participated in, a transmission system consisting of approximately:

| Nominal Voltage (in kilovolts) Transmission Lines | Miles(1) |
|---|---|
| 500 | 700 |
| 345 | 2,400 |
| 230 | 3,300 |
| 161 | 300 |
| 138 | 2,200 |
| 46 to 115 | 7,300 |
| | 16,200 |

(1) Includes PacifiCorp's share of jointly owned lines.

PacifiCorp's transmission and distribution system included approximately 900 substations as of December 31, 2011. PacifiCorp's transmission system, together with contractual rights on other transmission systems, enables PacifiCorp to integrate and access generation resources to meet its customer load requirements.

PacifiCorp's Energy Gateway Transmission Expansion Program represents plans to build approximately 2,000 miles of new high-voltage transmission lines, with an estimated cost exceeding $6 billion, primarily in Wyoming, Utah, Idaho and Oregon. The $6 billion estimated cost includes: (a) the 345-kV Populus to Terminal transmission line was fully placed in service in 2010; (b) the 100-mile high-voltage transmission line being built between the Mona substation in central Utah and the Oquirrh substation in the Salt Lake Valley expected to be placed in service in 2013; (c) the 345-kV transmission line being built between the Sigurd Substation in central Utah and the Red Butte Substation in southwest Utah expected to be placed in service in 2015; and (d) other segments that are expected to be placed in service through 2021, depending on siting, permitting and construction schedules. The transmission line segments are intended to: (a) address customer load growth; (b) improve system reliability; (c) reduce transmission system constraints; (d) provide access to diverse generation resources, including renewable resources; and (e) improve the flow of electricity throughout PacifiCorp's six-state service area. Proposed transmission line segments are re-evaluated to ensure optimal benefits and timing before committing to move forward with permitting and construction. Through December 31, 2011, $1.1 billion had been spent and $827 million, including amounts capitalized for equity AFUDC, had been placed in service.

PacifiCorp's transmission and distribution system is 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.

**Future Generation and Conservation**

*Integrated Resource Plan*

As required by certain state regulations, PacifiCorp uses an 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 while maintaining compliance with existing and evolving environmental laws and regulations. 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, state energy policies 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 and receives a formal notification in five states as to whether the IRP meets the commission's IRP standards and guidelines, which is referred to as "acknowledgment." In March 2011, PacifiCorp filed its 2011 IRP with the state commissions. In June 2011, an addendum to the 2011 IRP with supplemental resource analysis was filed with the state commissions. PacifiCorp has received acknowledgment of its 2011 IRP from the WPSC, the WUTC and the IPUC. In January 2012, PacifiCorp filed an updated 2011 IRP action plan with the OPUC containing additional details to respond to issues raised by parties to the acknowledgment proceedings.

*Requests for Proposals*

PacifiCorp has issued individual RFPs, each of which focuses on a specific category of electric generation resources consistent with the IRP. The IRP and the RFPs provide for the identification and staged procurement of resources in future years to achieve a balance of load requirements and resources. As required by applicable laws and regulations, PacifiCorp files draft RFPs with the UPSC, the OPUC and the WUTC prior to issuance to the market. Approval by the UPSC, the OPUC or the WUTC may be required depending on the nature of the RFPs.

PacifiCorp's All Source RFP sought up to 1,500 MW on a system-wide basis from projects with in-service dates from 2014 through 2016 and was issued to the market in December 2009. As a result, PacifiCorp signed an engineer, procure and construct contract for Lake Side 2, which is expected to be placed in service in June 2014. In April 2011, the UPSC issued an order approving the construction of Lake Side 2. The Lake Side 2 generating facility is currently being constructed adjacent to PacifiCorp's Lake Side generating facility, which is located in Vineyard, Utah, about 40 miles south of Salt Lake City.

In October 2011, PacifiCorp filed its draft All Source RFP for a 2016 resource with the UPSC and OPUC. The All Source RFP seeks approximately 600 MW of new base load, intermediate or summer-peaking energy on a system-wide basis from projects to be placed in service by June 2016. The All Source RFP was approved by the UPSC and issued to the market in January 2012.

In February 2012 as a result of the 2010S Solar RFP, PacifiCorp entered into an agreement to either acquire or lease the 2-MW Black Cap Solar generating facility to be constructed near Lakeview, Oregon. The expected commercial operation date is October 2012.

*Demand-side Management*

PacifiCorp has provided a comprehensive set of DSM 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. PacifiCorp offers 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. Although subject to prudence reviews, state regulations allow for contemporaneous recovery of costs incurred for the DSM programs through state-specific energy efficiency surcharges to retail customers or for recovery of costs through rates. In addition to these DSM programs, PacifiCorp has load curtailment contracts with a number of large industrial customers that deliver up to 305 MW of load reduction when needed. Recovery of the costs associated with the large industrial load management program is determined through PacifiCorp's general rate case process. During 2011, $114 million was expended on PacifiCorp's DSM programs, resulting in an estimated 539,197 MWh of first-year energy savings and an estimated 467 MW of peak load management. Total demand-side load available for control during 2011, including both load management from the large industrial curtailment contracts and DSM programs, was 719 MW.

**General Regulation**

PacifiCorp is subject to comprehensive governmental regulation, which significantly influences its operating environment, prices charged to customers, capital structure, costs and PacifiCorp's ability to recover costs. In addition to the following discussion, refer to "Liquidity and Capital Resources" in Item 7 and Note 5 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

*State Regulation*

Historically, state regulatory commissions have established retail rates on a cost-of-service basis, which are designed to allow a utility an opportunity to recover what state regulatory commissions deem to be the utility's reasonable costs of providing services, including a fair opportunity to earn a reasonable return on its investments. A utility's cost of service generally reflects its allowed operating expenses, including cost of fuel, purchased energy and transmission; operation and maintenance expense; depreciation expense; and income and other tax expense; reduced by wholesale electricity sales and other revenue. The allowed operating expenses are typically based on estimates of normalized costs, which may differ from realized costs in a given year covered by the established rates. State regulatory commissions may adjust rates pursuant to a review of (a) the utility's revenue and expenses during a defined test period, (b) the utility's level of investment or (c) for other reasons. State regulatory commissions typically have the authority to review and change rates on their own initiative; however, they may also initiate reviews at the request of a utility, 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.

PacifiCorp's retail rates are generally based on the cost of providing traditional bundled services, including generation, transmission and distribution services. PacifiCorp has established power cost adjustment mechanisms and other cost recovery mechanisms in certain states (as described in the table below), which help mitigate its exposure to changes in costs from those assumed in establishing base rates.

Except for Oregon and Washington, PacifiCorp has an exclusive right to serve retail customers within its service territories, and in turn, has the obligation to provide 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 this right on PacifiCorp's consolidated 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.

In addition to recovery through base rates, PacifiCorp also achieves recovery of certain costs through various adjustment mechanisms as summarized below.

| State Regulator | Base Rate Test Period | Adjustment Mechanism |
|---|---|---|
| UPSC | Forecasted or historical with known and measurable changes (1) | EBA under which 70% of the difference between base net power costs set during a general rate case and actual net power costs is deferred and reflected in future rates. |
| | | Balancing account to provide for the recovery or refund of the difference between the level of REC revenues included in base rates and actual REC revenues. |
| | | Recovery mechanism for single capital investments that in total exceed 1% of existing rate base when a general rate case has occurred within the preceding 18 months. |
| OPUC | Forecasted | Annual TAM based on forecasted net variable power costs; no true-up to actual net variable power costs. |
| | | RAC to recover the revenue requirement of new renewable resources and associated transmission that are not reflected in general rates. |
| | | Balancing account to provide for the refund of actual REC revenues. |
| WPSC | Forecasted or historical with known and measurable changes (1) | ECAM under which 70% of the difference between base net power costs set during a general rate case and actual net power costs is deferred and reflected in future rates. |
| | | REC and sulfur dioxide revenue adjustment mechanism to provide for recovery or refund of 100% of any difference between actual REC and sulfur dioxide revenues and the level forecasted in base rates. |
| WUTC | Historical with known and measurable changes | Deferral mechanism of costs for up to 24 months of new base load generation resources and eligible renewable resources and related transmission that qualify under the state's emissions performance standard and are not reflected in base rates. |
| | | REC revenue tracking mechanism to provide for the refund of Washington-allocated REC revenues. |
| IPUC | Historical with known and measurable changes | ECAM under which 90% of the difference between base net power costs set during a general rate case and actual net power costs is deferred and reflected in future rates. Also provides for recovery or refund of 100% of the difference between the level of REC and sulfur dioxide revenues included in base rates and actual REC and sulfur dioxide revenues. |
| CPUC | Forecasted | PTAM for major capital additions that allows for rate adjustments outside of the context of a traditional general 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. |
| | | ECAC that allows for an annual update to actual and forecasted net variable power costs. |
| | | PTAM for attrition, a mechanism that allows for an annual adjustment to costs other than net variable power costs. |

(1) PacifiCorp has relied on both historical test periods with known and measurable adjustments, as well as forecasted test periods.

Generally, PacifiCorp's DSM program costs are collected through separately established rates that are adjusted periodically based on actual and expected costs as approved by the respective state regulatory commission. As such, DSM program activities have no impact on net income.

*Federal Regulation*

The FERC is an independent agency with broad authority to implement provisions of the Federal Power Act, the Energy Policy Act of 2005 ("Energy Policy Act") and other federal statutes. The FERC regulates rates for wholesale sales of electricity; transmission of electricity, including pricing and regional planning for the expansion of transmission systems; electric system reliability; utility holding companies; accounting; securities issuances; and other matters, including construction and operation of hydroelectric facilities. The FERC also 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 that facilitate compliance 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 and transmission capacity and related services. Most of PacifiCorp's wholesale electricity sales and purchases occur under market-based pricing allowed by the FERC and are therefore subject to market volatility.

PacifiCorp is currently authorized by the FERC to sell electricity in wholesale electricity markets at market-based rates and is subject to triennial reviews conducted by the FERC. During such reviews, PacifiCorp must demonstrate a lack of market power over sales of wholesale electricity and electric generation capacity in its market areas. PacifiCorp's most recent triennial filing was made in June 2010. In June 2011, the FERC issued an order finding that PacifiCorp's submittals satisfied the FERC's requirements for market-based rate authority. The next triennial filing is due in June 2013. Under the FERC's market-based rules, PacifiCorp must also file with the FERC a notice of change in status when there is a significant change in the conditions that the FERC relied upon in granting market-based pricing authority.

*Transmission*

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 its OATT, PacifiCorp offers several transmission services to wholesale customers, including:

- Network transmission service (service that integrates generating resources to serve retail loads);
- Long- and short-term firm point-to-point transmission service (service with fixed delivery and receipt points); and
- Non-firm point-to-point service (service with fixed delivery and receipt points on an as available basis).

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 commercial and trading business in accordance with the FERC's Standards of Conduct. PacifiCorp has made several required compliance filings in accordance with these rules.

As described in "Regulatory Matters" in Item 7 of this Form 10-K, PacifiCorp adopted a cost-based formula rate under its OATT for its transmission services effective December 25, 2011. Cost-based formula rates are intended to be an effective means of recovering PacifiCorp's investments and associated costs of its transmission system without the need to file rate cases with the FERC, although the rates are subject to legal challenges at the FERC. A significant portion of these services are provided to PacifiCorp's commercial and trading function.

*FERC Reliability Standards*

The FERC has established an extensive number of reliability standards developed by the NERC and the WECC, including critical infrastructure protection standards and regional standard variations. PacifiCorp must comply with all applicable standards. Compliance, enforcement and monitoring oversight of these standards is carried out by the FERC, the NERC and the WECC. In 2007, the WECC audited PacifiCorp's compliance with several of the approved reliability standards, and in November 2008, the FERC assumed control of certain aspects of the WECC's audit. As discussed in Note 13 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K, in December 2011, the FERC approved a settlement among PacifiCorp, the FERC and the NERC that resolved the WECC audit items that were under the FERC's control, as well as certain other matters. The aspects of the 2007 audit not under the FERC's authority are closed as a result of PacifiCorp's July 2009 settlement with the WECC. The outcome of these matters did not have a material impact on PacifiCorp's consolidated financial results.

*Hydroelectric Relicensing*

PacifiCorp's Klamath River hydroelectric system is the only significant hydroelectric system for which PacifiCorp is currently 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 River hydroelectric system.

*Hydroelectric Decommissioning*

*Condit Hydroelectric Facility - White Salmon River, Washington*

In September 1999, a settlement agreement to remove the 14-MW Condit hydroelectric generating facility was signed by PacifiCorp, state and federal agencies and non-governmental organizations. In early February 2005, the parties agreed to modify the settlement agreement, establishing a total cost to decommission not to exceed $21 million, excluding inflation. In October 2010, the Washington Department of Ecology issued a Clean Water Act 401 certificate, and in December 2010, the FERC issued a surrender order for project decommissioning modifying PacifiCorp's proposed decommissioning plans and directing a 2011 decommissioning. In January 2011, PacifiCorp filed a request for clarification and rehearing of the surrender order and a motion for stay with the FERC requesting reinstatement of PacifiCorp's decommissioning proposal. In April 2011, the FERC issued an order on rehearing, granting PacifiCorp nearly all of the changes it requested, but did not shorten the required agency consultation and FERC approval periods. In June 2011, PacifiCorp formally notified the FERC of its acceptance of the terms and conditions of the orders that govern the surrender of the project license. PacifiCorp commenced on-site decommissioning activities in June 2011 and the dam was breached in late October 2011 as planned. Post breach, near-term activities will focus on sediment monitoring as material moves downstream into the Columbia River. Removal of project facilities commenced in January 2012, and complete dam removal is expected by August 2012.

*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 MSHA, which administers federal mine safety and health laws and regulations, and state regulatory agencies. MSHA has the statutory authority 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 penalties or fines for violations of federal mine safety standards. Federal law requires PacifiCorp to have a written emergency response plan specific to each underground mine it operates, which is reviewed by MSHA every six months, and to have at least two rescue teams located within one hour of each mine. Information regarding PacifiCorp's mine safety violations and other legal matters disclosed in accordance with Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank Reform Act") is included in Exhibit 95 to this Form 10-K.

**Environmental Laws and Regulations**

PacifiCorp is subject to federal, state and local laws and regulations regarding air and water quality, RPS, emissions performance standards, climate change, coal combustion byproduct disposal, hazardous and solid waste disposal, protected species and other environmental matters that have the potential to impact PacifiCorp's current and future operations. In addition to imposing continuing compliance obligations and capital expenditure requirements, these laws and regulations provide regulators with the authority to levy substantial penalties for noncompliance including fines, injunctive relief and other sanctions. These laws and regulations are administered by the EPA and various other state and local agencies. All such laws and regulations are subject to a range of interpretation, which may ultimately be resolved by the courts. Environmental laws and regulations continue to evolve, and PacifiCorp is unable to predict the impact of the changing laws and regulations on its operations and consolidated financial results. PacifiCorp believes it is in material compliance with all applicable laws and regulations.

Refer to "Liquidity and Capital Resources" in Item 7 of this Form 10-K for additional information regarding environmental laws and regulations and PacifiCorp's forecasted environmental-related capital expenditures.

## Item 1A. Risk Factors

We are subject to certain risks and uncertainties in our business operations, including, but not limited to, those described below. Careful consideration of these risks, together with all of the other information included in this Form 10-K and the other public information filed by us, should be made before making an investment decision. Additional risks and uncertainties not presently known or that are currently deemed immaterial may also impair our business operations.

### Our Corporate and Financial Structure Risks

***We have a substantial amount of debt, which could adversely affect our consolidated financial results.***

As of December 31, 2011, we had $6.845 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 may 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.

***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 long-term debt and preferred stock are rated investment grade by various rating agencies. We cannot assure that our long-term debt and preferred stock will 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, the principal source of short-term borrowings, could be significantly limited, resulting in higher interest costs.

Most of our large wholesale customers, suppliers and counterparties require us to maintain 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 certain counterparties may require collateral in the form of cash, a letter of credit or some other security for existing transactions and as a condition to entering into transactions with us. Such amounts may be material and may adversely affect our liquidity and cash flows.

***MEHC could exercise control 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 has control over all decisions requiring shareholder approval, including the election of our directors. 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.

### Our Business Risks

***We are subject to extensive federal, state and local legislation and regulation, including numerous environmental, health, safety and other laws and regulations that affect our operations and costs. These laws and regulations are complex, dynamic and subject to new interpretations or change. In addition, new laws and regulations are continually being proposed and enacted that create new or revised requirements or standards on our business.***

We are required to comply with numerous federal, state and local laws and regulations that have broad application to our business and limit our ability to independently make and implement management decisions regarding, among other items, acquiring businesses; constructing, acquiring or disposing of operating assets; operating generating facilities and transmission and distribution assets; setting rates charged to customers; establishing capital structures and issuing debt or equity securities; transactions with affiliates; and paying dividends. These laws and regulations are implemented and enforced by federal, state and local regulatory agencies, such as, among others, the FERC, the EPA, the MSHA and the various state regulatory commissions. Refer to "General Regulation" and "Environmental Laws and Regulations" in Item 1 of this Form 10-K for examples of laws and regulations and other requirements significantly affecting us and our present and future operations.

Compliance with applicable laws and regulations generally requires us to obtain and comply with a wide variety of licenses, permits, inspections and other approvals. Further, compliance with laws and regulations can require significant capital and operating expenditures, including expenditures for new equipment, inspection, cleanup costs, removal and remediation 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 laws and 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 or other regulatory approvals and permits for our operating assets or development projects. Delays in or active opposition by third parties to obtaining any required environmental or regulatory authorizations, failure to comply with the terms and conditions of the authorizations or enhanced 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 any environmental or other regulatory requirements, we may be subject to penalties and fines or other sanctions, including changes to the way our electric generating facilities are operated. The costs of complying with laws and regulations could adversely affect our consolidated financial results. Not being able to operate existing facilities or develop new generating facilities to meet customer electricity needs could require us to increase our purchases of electricity on the wholesale market, which could increase market and price risks and adversely affect our consolidated financial results.

Existing laws and regulations, while comprehensive, are subject to changes and revisions from ongoing policy initiatives by legislators and regulators and to interpretations that may ultimately be resolved by the courts. For example, changes in laws and regulations could result in, but are not limited to, increased competition within our service territories; new environmental requirements, including the implementation of RPS and GHG emissions reduction goals; the issuance of stricter air quality standards and the implementation of energy efficiency mandates; the issuance of regulations over the management and disposal of coal combustion byproducts; changes to our service territories as a result of condemnation or takeover by municipalities or other governmental entities, particularly where we lack the exclusive right to serve our customers; or a negative impact on our ability to recover costs.

In addition to changes in existing legislation and regulation, new laws and regulations are likely to be enacted that impose additional or new requirements or standards on our business. For example, while significant measures to regulate emissions at the federal level were considered by the United States Congress in 2010, comprehensive legislation has not been adopted; however, the EPA issued the Mercury and Air Toxics Standards ("MATS") rules in 2011. Implementing actions required under, and otherwise complying with, new federal and state laws and regulations and changes in existing ones are among the most challenging aspects of managing utility operations. We cannot predict the future course of new laws and regulations, changes in existing ones or new interpretations by agency orders or court decisions nor can their impact on us be determined at this time; however, any one of these could adversely affect our consolidated financial results through higher capital expenditures and operating costs and cause an overall change in how we operate our business. To the extent that we are not allowed by regulators to recover or cannot otherwise recover the costs to comply with new laws and regulations or changes in existing ones, the additional requirements could have a material adverse effect on our consolidated financial results. Additionally, even if such costs are recoverable in rates, if they are substantial and result in rates increasing to levels that substantially reduce customer demand, this could have a material adverse effect on our consolidated financial results.

***Recovery of our costs is subject to regulatory review and approval, and the inability to recover costs may adversely affect our consolidated 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 further uncertainty associated with the approval proceedings.

Each state sets retail rates based in part upon the state regulatory 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 may not be sufficient to cover those costs. In some cases, actual costs are lower than the normalized or estimated costs determined during the ratemaking process and from time-to-time may result in a state regulator requiring refunds to customers. Each state regulatory commission generally sets rates based on a test year established in accordance with that commission's policies. The test year data adopted by each state regulatory commission may create a lag between the incurrence of a cost and its recovery in rates. Each state regulatory commission also decides the allowed levels of expense and investment that they deem are just and reasonable in providing the service and may disallow recovery in rates for any costs that do not meet such standard. Additionally, each state regulatory commission establishes the allowed rate of return we will be given an opportunity to earn on our sources of capital. While rate regulation is premised on providing a fair opportunity to earn 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.

In certain states where energy cost adjustment mechanisms are in place, energy cost increases above the level assumed in establishing base rates are subject to customer sharing, and in certain states, we are not permitted to pass through such energy cost increases without a general rate case. Any significant increase in fuel costs for electricity generation or purchased electricity costs could have a negative impact on us, despite efforts to minimize this impact through the use of hedging contracts and sharing mechanisms or through future general rate cases. Any of these consequences could adversely affect our consolidated financial results.

*FERC Jurisdiction*

The FERC establishes cost-based rates under which we provide transmission services to wholesale and retail markets in states that allow retail competition. Under the Federal Power Act, we may voluntarily file, or may be obligated to file, for changes, including general rate changes, to our system-wide transmission service rates. General rate changes implemented may be subject to refund. The FERC also has responsibility for approving both cost- and market-based rates under which we sell electricity at wholesale, has licensing authority over most of our hydroelectric generating facilities and has broad jurisdiction over energy markets. The FERC may impose price limitations, bidding rules and other mechanisms to address some of the volatility of these markets or could revoke or restrict our ability to sell electricity at market-based rates, which could adversely affect our consolidated 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 are subject to significant risk, and we have significant funding needs related to our planned capital expenditures.***

We actively pursue, develop and construct new or expanded facilities. We expect that we will incur substantial annual capital expenditures over the next several years. Such expenditures could include, among others, amounts for new electric generating facilities, electric transmission or distribution projects, environmental control and compliance systems, as well as the continued maintenance and upgrades of existing assets.

Development and construction of major facilities are subject to substantial risks, including fluctuations in the price and availability of commodities, manufactured goods, equipment, labor, siting and permitting and other items over a multi-year construction period, as well as counterparty risk and the economic viability of our suppliers, customers and contractors. Certain of our construction projects are substantially dependent upon a single contractor and replacement of such contractor may be difficult and cannot be assured. These risks may result in the inability to timely complete a project or higher than expected costs to complete an asset and place it in service. Such costs may not be recoverable in the retail 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 consolidated financial results.

Furthermore, we depend upon both internal and external sources of liquidity to provide working capital and to fund capital requirements. If we are unable to obtain funding from internal and external sources, 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 electricity service to our customers. For example, if we are not able to expand our existing portfolio of generating facilities, we may be required to enter into long-term wholesale electricity purchase contracts or purchase wholesale electricity at more volatile and potentially higher prices in the spot markets to support retail loads.

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

- a depression, recession or other adverse economic condition that results in a lower level of economic activity or reduced spending by consumers on electricity, including the significant adverse changes in the economy and credit markets experienced in 2008 and 2009;
- 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 the 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 the fuel source for electricity generation or that limit the use of 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 associated with the wholesale energy markets, which could adversely affect our consolidated financial results.***

In general, our primary market risk is the risk of adverse fluctuations in the market price of wholesale electricity and fuel, including natural gas, coal and fuel oil, which is compounded by volumetric changes affecting the availability of or demand for electricity and fuel. The market price of wholesale electricity may be influenced by several factors, such as the adequacy or type of generating capacity, scheduled and unscheduled outages of generating facilities, prices and availability of fuel sources for generation, disruptions or constraints to transmission and distribution facilities, weather conditions, economic growth and changes in technology. Volumetric changes are caused by unanticipated changes in generation availability or changes in customer needs that can be due to the weather, electricity and fuel prices, the economy, regulations or customer behavior. For example, we purchase electricity and fuel in the open market 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.

***We are subject to counterparty credit risk, which could adversely affect our consolidated financial results.***

We are subject to counterparty credit risk related to contractual obligations with wholesale suppliers and customers. Adverse economic conditions or other events affecting counterparties with whom we conduct business could impair the ability of these counterparties to timely pay for services. We depend on these counterparties to remit payments on a timely basis. For example, certain wholesale suppliers and customers experienced deteriorating credit quality in 2008 and 2009. If our wholesale customers are unable to pay us for energy, there may be a significant adverse impact on our consolidated financial results.

We continue to monitor the creditworthiness of wholesale suppliers and customers in an attempt to reduce the impact of any potential counterparty default. If strategies used to minimize these risk exposures are ineffective or if our wholesale customers' financial condition deteriorates as a result of economic conditions causing them to be unable to pay, significant losses could result. Although we monitor the creditworthiness of our customers in an attempt to reduce the impact of any potential counterparty default, defaults in payment could adversely affect our consolidated financial results.

***We are subject to counterparty performance risk, which could adversely affect our consolidated financial results.***

We are subject to counterparty performance risk related to performance of contractual obligations by wholesale suppliers and customers. We rely on wholesale 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 the delivery of electricity and require us to incur additional expenses to meet customer needs. In addition, when these contracts terminate, we may be unable to purchase the commodities on terms equivalent to the terms of current contracts.

We rely on wholesale customers to take delivery of the energy they have committed to purchase. 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. If our wholesale customers are unable to fulfill their obligations, there may be a significant adverse impact on our consolidated financial results.

***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.***

During 2008 and 2009, the United States and global credit markets experienced historic dislocations and liquidity disruptions that caused financing to be unavailable in certain cases. These circumstances materially impacted liquidity in the bank and debt capital markets during this period, making financing terms less attractive for borrowers that were able to find financing, and in other cases resulted in the unavailability of certain types of debt financing. While there has been a gradual recovery in the United States economy and an improvement in its financial markets, there remains much financial and economic uncertainty on a global basis, especially in the European community, which may adversely affect the United States' credit markets. Uncertainty in the credit markets may negatively impact our ability to access funds on favorable terms or at all. If we are unable to access the bank and debt markets to meet liquidity and capital expenditure needs, it may adversely affect the timing and amount of our capital expenditures and our consolidated financial results.

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

Inflation may affect our business by increasing both operating and capital costs. If we are unable to manage cost increases or successfully pass them on to our customers, our consolidated financial results could be adversely affected.

***Our consolidated financial results may be adversely affected if we are unable to obtain adequate, reliable and affordable access to electricity transmission service and natural gas transportation.***

We depend on electricity transmission and natural gas transportation facilities owned and operated by other companies to transport electricity to both wholesale and retail markets and to transport natural gas purchased to supply certain of our generating facilities. A lack of available transmission and transportation could hinder us from providing adequate or cost-effective electricity to our retail customers and wholesale markets, which could adversely affect our consolidated financial results.

The different regional power markets have varying and dynamic regulatory structures, which could affect our growth and performance. In addition, the independent system operators who oversee the transmission systems in certain portions of the regional power markets in which we transact have imposed in the past, and may impose in the future, price limitations and other mechanisms to counter volatility in the power markets. These types of price limitations and other mechanisms may adversely affect our consolidated financial results.

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

In the markets in which we operate, demand for electricity peaks during the hot summer months when irrigation and cooling needs are higher. Market prices for electricity also generally peak at that time. In other areas, demand for electricity peaks during the winter when heating needs are higher. Further, extreme weather conditions, such as heat waves, winter storms or floods could cause these seasonal fluctuations to be more pronounced. Periods of low rainfall or snowpack may impact electricity generation at our hydroelectric generating facilities, which may result in greater purchases of electricity from the wholesale market or from other sources at market prices. Additionally, we have added substantial wind-powered generating capacity, which is also a climate-dependent resource.

As a result, our overall consolidated financial results may fluctuate substantially on a seasonal and quarterly basis. We have historically sold less energy, and consequently earned less income, when weather conditions are mild. Unusually mild weather in the future may adversely affect our consolidated financial results through lower revenue or margins. Conversely, unusually extreme weather conditions could increase our costs to provide energy and could adversely affect our consolidated financial results. The extent of fluctuation in our consolidated financial results may change depending on a number of factors related to our regulatory environment and contractual agreements, including our ability to recover energy costs and terms of the wholesale sale contracts.

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

The operation of complex, integrated 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 electricity generating 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; cyber attacks; 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, floods, fires, earthquakes, explosions and mining accidents. A catastrophic event 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 revenue or significantly increase our expenses. For example, if we cannot operate our generating facilities at full capacity due to damage caused by a catastrophic event, our revenue could decrease 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. The scope, cost and availability of our insurance coverage may change, including the portion that is self-insured. Any reduction of our revenue or increase in our expenses resulting from the risks described above, could adversely affect our consolidated financial results.

***Potential terrorist activities or military or other actions, including cyber attacks could adversely affect our consolidated financial results.***

The ongoing threat of terrorism and the impact of military and other actions by the United States and its allies create increased political, economic and financial market instability, which subjects our operations to increased risks. The United States government has issued warnings that energy assets, specifically electric utility infrastructure, are potential targets for terrorist organizations. Cyber attacks could adversely affect our ability to operate our facilities, information technology and business systems, or compromise confidential customer and employee information. 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, particularly with respect to electricity and natural gas, 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 consolidated financial results. Furthermore, instability in the financial markets as a result of terrorism, sustained or significant cyber attacks, or war could also materially adversely affect our ability to raise capital.

***Poor performance of plan and fund investments and other factors impacting the pension and other postretirement benefit plans, the multiemployer plans to which we contribute and mine reclamation trust funds could unfavorably impact our cash flows and liquidity.***

Costs of providing our defined benefit pension and other postretirement benefit plans, as well as costs associated with the multiemployer plans to which we contribute, 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 benefit plans, as well as certain multiemployer plans to which we contribute, are in 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 in the future. To the extent a mass withdrawal from any of the multiemployer plans to which we have contributed occurs, we may be subject to a mass withdrawal liability associated with unfunded vested benefits even if we voluntarily withdrew from the plan up to three years prior to the mass withdrawal. Additionally, our pension and other postretirement benefit plans have investments in sovereign debt and foreign currency denominated securities. Credit rating downgrades and default by the entities in which our plans have invested could add to the volatility and timing of future contributions. Furthermore, the Pension Protection Act of 2006, as amended, may result in more volatility in the amount and timing of future contributions. Similarly, funds dedicated to mine reclamation are invested in debt and equity 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 consolidated 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 consolidated 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 consolidated 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 consolidated financial results.

***Potential changes in accounting standards may impact our consolidated financial results and disclosures in the future, which may change the way analysts measure our business or financial performance.***

The Financial Accounting Standards Board ("FASB") and the SEC continuously make changes to accounting standards and disclosure and other financial reporting requirements. New or revised accounting standards and requirements issued by the FASB or the SEC or new accounting orders issued by the FERC could significantly impact our consolidated financial results and disclosures.

**Item 1B. Unresolved Staff Comments**

None.

## Item 2. Properties

PacifiCorp's properties consist of the physical assets necessary to support its electricity business, which include electric generation, transmission and distribution facilities, as well as coal mining assets that support certain of PacifiCorp's electric generating facilities. In addition to these physical assets, PacifiCorp has rights-of-way, mineral rights and water rights that enable PacifiCorp to utilize its facilities. 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 electric 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 governmental or Native American tribal lands.

With respect to real property, each of the transmission and distribution facilities fall into two basic categories: (a) parcels that are owned in fee, such as certain of PacifiCorp's generating facilities, substations and office sites; and (b) 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

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 impact 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, penalties and other costs in substantial amounts and are described below.

In December 2000, Wah Chang, a large industrial customer of PacifiCorp filed an action before the OPUC asserting that the rates set by a special tariff with PacifiCorp and approved by the OPUC were not just and reasonable due to alleged market manipulation during the energy crisis. In October 2001, the OPUC dismissed Wah Chang's petition and found that Wah Chang assumed the risk of price increases under the special tariff. Wah Chang petitioned the Circuit Court for Marion County, Oregon for review of the OPUC's order. In June 2002, the Circuit Court for Marion County, Oregon granted Wah Chang's motion for review and ordered the OPUC to reopen the record to allow Wah Chang the opportunity to present new evidence. In September 2009, the OPUC dismissed Wah Chang's petition and reaffirmed that the rates set by the special tariff were just and reasonable. In October 2009, Wah Chang filed with the Oregon Court of Appeals a petition for judicial review of the OPUC's September 2009 order denying Wah Chang relief. In July 2010, the Oregon Court of Appeals accepted judicial review.

In a separate but related proceeding, in December 2000, Wah Chang filed a complaint in the Circuit Court for Linn County, Oregon asserting that the OPUC-approved special tariff with PacifiCorp is subject to rescission based on theories of mutual mistake of fact, frustration of purpose and impracticability. In April 2011, Wah Chang's claims were presented during a jury trial, and all claims, including the claim for punitive damages, were resolved in PacifiCorp's favor. Wah Chang did not appeal this outcome and the outcome had no impact on PacifiCorp's consolidated financial results.

In October 2005, PacifiCorp was added as a defendant to a lawsuit originally filed in February 2005 in the Third District Court for Salt Lake County, Utah ("Third District Court") by USA Power, LLC and its affiliated companies, USA Power Partners, LLC and Spring Canyon Energy, 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 generating facility. 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. The statutory doubling of damages only applies to the plaintiffs' trade secret claim and could increase the total damages sought to $500 million. 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 by the Utah Supreme Court of two of their five claims. In May 2010, the Utah Supreme Court reversed and remanded the case back to the Third District Court for further consideration. The Third District Court set an eight-week trial for June and July 2011, but postponed the trial just before it was set to begin. In September 2011, the case was assigned to a new judge who established a new trial date beginning April 2012. PacifiCorp cannot predict the outcome of these proceedings, but believes that the outcome will not have a material impact on its consolidated financial results.

## Item 4. Mine Safety Disclosures

Information regarding PacifiCorp's mine safety violations and other legal matters disclosed in accordance with Section 1503(a) of the Dodd-Frank Reform Act is included in Exhibit 95 to this Form 10-K.

## 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.

In January 2012, PacifiCorp declared a dividend of $50 million, which was paid to PPW Holdings in February 2012.

In January 2011, PacifiCorp declared a dividend of $275 million, which was paid to PPW Holdings in February 2011. In March 2011, PacifiCorp declared a dividend of $275 million, which was paid to PPW Holdings in April 2011. PacifiCorp did not declare or pay dividends on common stock during the year ended December 31, 2010.

During the year ended December 31, 2010, PacifiCorp received cash capital contributions of $100 million from MEHC.

For a discussion of regulatory restrictions that limit PacifiCorp's ability to pay dividends on common stock, refer to "Limitations" in Item 7 and 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).

| | Years Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2011 | 2010 | 2009 | 2008 | 2007 |
| **Consolidated Statement of Operations Data:** | | | | | |
| Operating revenue | $ 4,586 | $ 4,432 | $ 4,457 | $ 4,498 | $ 4,258 |
| Operating income | 1,084 | 1,036 | 1,060 | 954 | 894 |
| Net income attributable to PacifiCorp | 555 | 566 | 542 | 458 | 439 |

| | As of December 31, | | | | |
|---|---|---|---|---|---|
| | 2011 | 2010 | 2009 | 2008 | 2007 |
| **Consolidated Balance Sheet Data:** | | | | | |
| Total assets | $ 21,106 | $ 20,146 | $ 18,966 | $ 17,167 | $ 14,907 |
| Short-term debt | 688 | 36 | — | 85 | — |
| Current portion of long-term debt and capital lease obligations | 19 | 588 | 16 | 144 | 414 |
| Long-term debt and capital lease obligations, excluding current portion(1) | 6,194 | 5,813 | 6,400 | 5,424 | 4,753 |
| Preferred stock | 41 | 41 | 41 | 41 | 41 |
| Total PacifiCorp shareholders' equity | 7,312 | 7,311 | 6,648 | 5,987 | 5,080 |

(1) In January 2012, PacifiCorp issued $350 million of its 2.95% First Mortgage Bonds due February 1, 2022 and $300 million of its 4.10% First Mortgage Bonds due February 1, 2042.

## 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 consolidated financial condition and results of operations of PacifiCorp during the periods included herein. Explanations include management's best estimate of the impact 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 to Consolidated Financial Statements 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

*Overview*

Net income attributable to PacifiCorp for the year ended December 31, 2011 was $555 million, a decrease of $11 million, or 2%, as compared to 2010. Net income attributable to PacifiCorp decreased primarily due to lower wholesale sales prices and volumes, higher volumes of purchased electricity, higher coal prices, higher depreciation and property tax expenses due to higher plant in service, lower AFUDC due to lower construction work-in-progress and lower sales of renewable energy credits, partially offset by higher retail prices approved by regulators, higher retail customer load and the net impact of the Utah general rate case settlement. Energy supplied increased 1% for 2011 compared to 2010 due to higher purchased electricity volumes, higher than average hydroelectric generation and higher wind-powered generation, partially offset by lower generation from natural gas and coal-fueled generating facilities.

Net income attributable to PacifiCorp for the year ended December 31, 2010 was $566 million, an increase of $24 million, or 4%, as compared to 2009. Net income attributable to PacifiCorp increased due to higher retail prices approved by regulators, higher sales of renewable energy credits, higher benefits associated with deferred net power costs, higher allowances for funds used during construction and a lower effective tax rate, partially offset by lower net wholesale electricity activities, higher depreciation on higher plant in service and higher operations and maintenance expense.

Operating revenue and energy costs are the key drivers of PacifiCorp's results of operations as they encompass retail and wholesale electricity sales and the direct costs associated with providing electricity to customers, which include the costs of fuel, wholesale electricity purchases and transmission. PacifiCorp believes that a discussion of gross margin, representing operating revenue less energy costs, is therefore meaningful.

PacifiCorp adopted authoritative guidance as of January 1, 2010 that required the deconsolidation of its majority owned coal mining joint venture, Bridger Coal. As a result, Bridger Coal has been accounted for under the equity method since January 1, 2010. The deconsolidation of Bridger Coal had no impact on net income attributable to PacifiCorp. Prior to the deconsolidation of Bridger Coal, PacifiCorp adopted authoritative guidance on January 1, 2009 that established accounting and reporting standards for the noncontrolling interest in a subsidiary. This guidance impacted PacifiCorp's presentation of both revenue and expense associated with the noncontrolling interest in Bridger Coal and had no impact on net income attributable to PacifiCorp during the year ended December 31, 2009.

*Year Ended December 31, 2011 Compared to Year Ended December 31, 2010*

A comparison of PacifiCorp's key operating results is as follows for the years ended December 31:

| | | | | | Favorable/(Unfavorable) | | |
|---|---|---|---|---|---|---|---|
| | | 2011 | | 2010 | | Change | % Change |
| Gross margin (in millions): | | | | | | | |
| Operating revenue | $ | 4,586 | $ | 4,432 | $ | 154 | 3 % |
| Energy costs | | 1,636 | | 1,618 | | (18) | (1) |
| Gross margin | $ | 2,950 | $ | 2,814 | $ | 136 | 5 % |
| Volumes of electricity sold (in GWh): | | | | | | | |
| Residential | | 16,046 | | 15,795 | | 251 | 2 % |
| Commercial | | 16,489 | | 15,969 | | 520 | 3 |
| Industrial and irrigation | | 21,229 | | 20,680 | | 549 | 3 |
| Other | | 543 | | 572 | | (29) | (5) |
| Total retail electricity sales | | 54,307 | | 53,016 | | 1,291 | 2 |
| Wholesale electricity sales | | 10,767 | | 11,415 | | (648) | (6) |
| Total electricity sales | | 65,074 | | 64,431 | | 643 | 1 % |
| Retail electricity sales: | | | | | | | |
| Average retail customers (in thousands) | | 1,742 | | 1,733 | | 9 | 1 % |
| Average revenue per MWh | $ | 74.79 | $ | 70.01 | $ | 4.78 | 7 % |
| Wholesale electricity sales: | | | | | | | |
| Average revenue per MWh | $ | 32.49 | $ | 43.02 | $ | (10.53) | (24)% |
| Volumes of electricity generated (in GWh): | | | | | | | |
| Coal-fueled generation | | 40,789 | | 42,612 | | (1,823) | (4)% |
| Natural gas-fueled generation | | 6,320 | | 8,416 | | (2,096) | (25) |
| Hydroelectric generation | | 4,680 | | 3,744 | | 936 | 25 |
| Other | | 3,652 | | 2,862 | | 790 | 28 |
| Total PacifiCorp generated volumes | | 55,441 | | 57,634 | | (2,193) | (4)% |
| Volumes of electricity purchased (in GWh): | | | | | | | |
| Wholesale electricity purchases | | 13,963 | | 11,329 | | (2,634) | (23)% |
| Cost of wholesale electricity purchased: | | | | | | | |
| Average cost per MWh | $ | 38.41 | $ | 38.50 | $ | 0.09 | — % |

*Gross margin* increased $136 million, or 5%, for 2011 compared to 2010 primarily due to:

- $280 million of increases from higher retail prices approved by regulators;
- $81 million of increases due to higher commercial customer load primarily in Utah and Oregon, higher industrial customer load in Utah and the impacts of colder weather on residential customer load in Oregon;
- $76 million of increases due to net higher deferrals of incurred power costs in accordance with established adjustment mechanisms, including $60 million resulting from the Utah general rate case settlement in the current year for the recovery of incurred power costs; and
- $8 million of increases resulting from lower fuel costs primarily due to $72 million of lower volumes of natural gas consumed and $30 million of lower volumes of coal consumed, partially offset by $91 million of higher coal prices partially due to higher priced third-party coal contracts.

The increase in gross margin was partially offset by:

- $241 million of decreases resulting from higher volumes of purchased electricity and lower volumes of wholesale electricity sales, both at lower average market prices and including the impact of financial swaps;
- $57 million of decreases from lower sales and higher deferrals of renewable energy credits, net of amortization, including $30 million of decreases resulting from the Utah general rate case settlement in the current year for the return to customers of past sales of renewable energy credits in excess of what was assumed in establishing base rates; and
- $11 million of decreases due to the elimination of certain regulatory liabilities in 2010 resulting from the Utah DSM settlement and the Utah general rate case order.

*Operations and maintenance* increased $22 million, or 2%, for 2011 compared to 2010 primarily due to higher salaries and benefits expenses and higher materials and supplies expenses, partially offset by the write-off of a portion of a Utah DSM regulatory asset in 2010.

*Depreciation and amortization* increased $50 million, or 9%, for 2011 compared to 2010 primarily due to higher plant in service, accelerated depreciation and amortization of certain Klamath hydroelectric system assets and the prior year impact of revised depreciation rates for distribution assets in California.

*Taxes, other than income taxes* increased $16 million, or 12%, for 2011 compared to 2010 primarily due to increased property taxes due to higher plant in service.

*Interest expense* increased $5 million, or 1%, for 2011 compared to 2010 primarily due to interest accruals associated with the return to customers of past sales of renewable energy credits according to the Utah general rate case settlement and higher average debt outstanding, partially offset by lower average rates during the year.

*Allowances for borrowed and equity funds* decreased $52 million, or 42%, for 2011 compared to 2010 primarily due to lower qualified construction work-in-progress balances.

*Year Ended December 31, 2010 Compared to Year Ended December 31, 2009*

A comparison of PacifiCorp's key operating results is as follows for the years ended December 31:

| | | | | | | Favorable/(Unfavorable) | |
|---|---|---|---|---|---|---|---|
| | | 2010 | | 2009 | | Change | % Change |
| Gross margin (in millions): | | | | | | | |
| Operating revenue | $ | 4,432 | $ | 4,457 | $ | (25) | (1)% |
| Energy costs | | 1,618 | | 1,677 | | 59 | 4 |
| Gross margin | $ | 2,814 | $ | 2,780 | $ | 34 | 1 % |
| Volumes of electricity sold (in GWh): | | | | | | | |
| Residential | | 15,795 | | 15,999 | | (204) | (1)% |
| Commercial | | 15,969 | | 16,194 | | (225) | (1) |
| Industrial and irrigation | | 20,680 | | 19,934 | | 746 | 4 |
| Other | | 572 | | 583 | | (11) | (2) |
| Total retail electricity sales | | 53,016 | | 52,710 | | 306 | 1 |
| Wholesale electricity sales | | 11,415 | | 12,349 | | (934) | (8) |
| Total electricity sales | | 64,431 | | 65,059 | | (628) | (1)% |
| Retail electricity sales: | | | | | | | |
| Average retail customers (in thousands) | | 1,733 | | 1,719 | | 14 | 1 % |
| Average revenue per MWh | $ | 70.01 | $ | 67.68 | $ | 2.33 | 3 % |
| Wholesale electricity sales: | | | | | | | |
| Average revenue per MWh | $ | 43.02 | $ | 51.95 | $ | (8.93) | (17)% |
| Volumes of electricity generated (in GWh): | | | | | | | |
| Coal-fueled generation | | 42,612 | | 43,854 | | (1,242) | (3)% |
| Natural gas-fueled generation | | 8,416 | | 8,576 | | (160) | (2) |
| Hydroelectric generation | | 3,744 | | 3,544 | | 200 | 6 |
| Other | | 2,862 | | 2,427 | | 435 | 18 |
| Total PacifiCorp generated volumes | | 57,634 | | 58,401 | | (767) | (1)% |
| Volumes of electricity purchased (in GWh): | | | | | | | |
| Wholesale electricity purchases | | 11,329 | | 10,975 | | (354) | (3)% |
| Cost of wholesale electricity purchased: | | | | | | | |
| Average cost per MWh | $ | 38.50 | $ | 42.95 | $ | 4.45 | 10 % |

*Gross margin* increased $34 million, or 1%, for 2010 compared to 2009 primarily due to:

- $138 million of increases from higher retail prices approved by regulators, including $40 million of increases in DSM revenue primarily associated with Utah and Oregon DSM programs;
- $43 million of increases from sales of renewable energy credits, net of deferrals;
- $39 million of increases due to higher deferrals of incurred power costs and lower amortization of previous deferrals in accordance with established adjustment mechanisms;
- $14 million of increases resulting from the elimination of certain regulatory liabilities in 2010 resulting from the Utah DSM settlement and the Utah general rate case order; and
- $6 million of decreases in fuel costs primarily due to lower average prices paid for natural gas and lower volumes of coal and natural gas consumed, substantially offset by increased coal prices.

The increase in gross margin was partially offset by:

- $115 million of decreases in net wholesale electricity activities due to lower average prices and volumes of wholesale electricity sales and higher volumes of purchased electricity, partially offset by lower average prices on purchased electricity, including the impact of financial swaps;
- $66 million of decreases from lower revenue related to the deconsolidation of Bridger Coal;
- $18 million of decreases resulting from higher transmission expense due to higher contract rates; and
- $8 million of decreases due to lower customer load in the western side of PacifiCorp's service territory primarily due to impacts of cooler weather, partially offset by higher industrial customer load and higher growth in the average number of customers in the eastern side of PacifiCorp's service territory.

*Operations and maintenance* increased $46 million, or 4%, for 2010 compared to 2009 primarily due to higher Utah and Oregon DSM expenses, the write-off of a portion of the Utah DSM regulatory asset in 2010 resulting from the Utah DSM settlement and the Utah general rate case order and higher costs associated with jointly owned generating facilities primarily due to increased overhauls, partially offset by lower costs related to the deconsolidation of Bridger Coal.

*Depreciation and amortization* increased $12 million, or 2%, for 2010 compared to 2009 primarily due to higher plant in service, partially offset by revised depreciation rates for distribution assets in California and $10 million of lower depreciation related to the deconsolidation of Bridger Coal.

*Taxes, other than income taxes* were consistent with the prior year, but included $13 million of increased property taxes, substantially offset by decreases related to the deconsolidation of Bridger Coal.

*Allowances for borrowed and equity funds* increased $25 million, or 25%, for 2010 compared to 2009 primarily due to higher qualified construction work-in-progress balances.

*Interest income* decreased $14 million, or 74%, for 2010 compared to 2009 primarily due to interest recognized in 2009 associated with Oregon Senate Bill 408 ("SB 408").

*Income tax expense* decreased $23 million for 2010 compared to 2009 and the effective tax rates were 27% and 30% for 2010 and 2009, respectively. The decrease in PacifiCorp's effective tax rate was primarily due to the effects of ratemaking and higher production tax credits associated with PacifiCorp's wind-powered generating facilities.

## Liquidity and Capital Resources

As of December 31, 2011, PacifiCorp's total net liquidity was $410 million. The components of total net liquidity were as follows (in millions):

| | | |
|---|---|---|
| Cash and cash equivalents | $ | 47 |
| Available revolving credit facilities | $ | 1,355 |
| Less: | | |
| Short-term debt | | (688) |
| Letters of credit supporting tax-exempt bond obligations | | (304) |
| Net revolving credit facilities available | $ | 363 |
| Total net liquidity | $ | 410 |
| Unsecured revolving credit facilities: | | |
| Maturity dates(1) | | 2012, 2013 |
| Largest single bank commitment as a % of total(2) | | 16% |

(1) For further discussion regarding PacifiCorp's credit facilities, refer to Note 8 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

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

In September 2010, the President signed the Small Business Jobs Act into law, extending retroactively to January 1, 2010 the 50% bonus depreciation for qualifying property purchased and placed in service in 2010. In December 2010, the President signed the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 into law, which provided for 100% bonus depreciation for qualifying property purchased and placed in service after September 8, 2010 and prior to January 1, 2012, and extended 50% bonus depreciation for qualifying property purchased and placed in service after December 31, 2010 and prior to January 1, 2013. As a result of the new laws, PacifiCorp's cash flows from operations are expected to benefit in 2012 due to bonus depreciation on qualifying assets placed in service.

*Operating Activities*

Net cash flows from operating activities for the years ended December 31, 2011 and 2010 were $1.636 billion and $1.410 billion, respectively. The $226 million increase was primarily due to higher retail prices approved by regulators and changes in collateral posted for derivative contracts, partially offset by lower net wholesale electricity activities.

Net cash flows from operating activities for the years ended December 31, 2010 and 2009 were $1.410 billion and $1.500 billion, respectively. The $90 million decrease was primarily due to changes in collateral posted for derivative contracts, lower net wholesale electricity activities and higher contributions to PacifiCorp's pension plan, partially offset by higher prices approved by regulators and higher income tax receipts in 2010 primarily related to bonus depreciation.

*Investing Activities*

Net cash flows from investing activities for the years ended December 31, 2011 and 2010 were $(1.529) billion and $(1.613) billion, respectively. Capital expenditures decreased $101 million primarily due to lower expenditures for clean air initiatives and transmission system investments, partially offset by higher expenditures for new generating facilities.

Net cash flows from investing activities for the years ended December 31, 2010 and 2009 were $(1.613) billion and $(2.308) billion, respectively. Capital expenditures decreased $721 million primarily due to lower expenditures for transmission system investments and wind-powered generating facilities.

*Capital Expenditures*

Capital expenditures incurred consisted of the following during the years ended December 31 and exclude amounts for non-cash equity AFUDC:

2011

- Transmission system investments totaling $216 million, including permitting and right-of-way costs for the 100-mile high-voltage transmission line being built between the Mona substation in central Utah and the Oquirrh substation in the Salt Lake Valley. A 65-mile segment of the Mona to Oquirrh transmission project will be a single-circuit 500-kV transmission line, while the remaining 35-mile segment will be a double-circuit 345-kV transmission line. The transmission line is expected to be placed in service in 2013.

- Emissions control equipment on existing generating facilities totaling $189 million for installation or upgrade of sulfur dioxide scrubbers, low nitrogen oxide burners and particulate matter control systems, including costs for projects that were placed in service in the spring and fall of 2011.

- The development and construction of the Lake Side 2 totaling $180 million, which is expected to be placed in service in 2014.

- Distribution, generation, mining and other infrastructure needed to serve existing and expected demand totaling $921 million.

2010

- Emissions control equipment totaling $347 million, including costs for the Dave Johnston generating facility Unit 3, which includes a sulfur dioxide scrubber that was placed in service in May 2010, as well as low nitrogen oxide burners and costs for installation or upgrade of sulfur dioxide scrubbers on various other generating facilities.

- Transmission system investments totaling $293 million, including construction costs for the first major segment of the Energy Gateway Transmission Expansion Program, a 135-mile, double-circuit, 345-kV transmission line between the Populus substation in southern Idaho and the Terminal substation near Salt Lake City, Utah, which was fully placed in service in 2010.

- The development and construction of wind-powered generating facilities totaling $148 million, for the 111-MW Dunlap Ranch I wind-powered generating facility near Medicine Bow, Wyoming, which was placed in service in October 2010.

- Distribution, generation, mining and other infrastructure needed to serve existing and expected demand totaling $819 million.

2009

- Transmission system investments totaling $699 million, including construction costs for a major segment of the Energy Gateway Transmission Expansion Program.

- Emissions control equipment totaling $353 million, including the installation costs for emissions control equipment at the Dave Johnston generating facility related to the addition of a new sulfur dioxide scrubber on Unit 3 and the replacement of an existing sulfur dioxide scrubber on Unit 4, which is expected to be placed into service during 2012. Additional projects included installation of sulfur dioxide scrubbers on various other generating facilities.

- The development and construction of wind-powered generating facilities totaling $220 million, including 127 MW placed in service in September 2009 and construction costs for the 111-MW Dunlap Ranch I wind-powered generating facility.

- Distribution, generation, mining and other infrastructure needed to serve existing and expected demand totaling $1.056 billion.

*Financing Activities*

*Short-term Debt and Revolving Credit Facilities*

Regulatory authorities limit PacifiCorp to $1.5 billion of short-term debt. PacifiCorp had $688 million of short-term debt outstanding as of December 31, 2011 at a weighted-average interest rate of 0.5% as compared to $36 million of short-term debt outstanding as of December 31, 2010 at a weighted-average interest rate of 0.3%. PacifiCorp had no outstanding borrowings under its unsecured revolving credit facilities as of December 31, 2011 or 2010.

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 January 2012, PacifiCorp issued $350 million of its 2.95% First Mortgage Bonds due February 1, 2022 and $300 million of its 4.10% First Mortgage Bonds due February 1, 2042. The net proceeds were used to repay short-term debt, fund capital expenditures and for general corporate purposes. PacifiCorp currently has regulatory authority from the OPUC and the IPUC to issue an additional $950 million of long-term debt. PacifiCorp must make a notice filing with the WUTC prior to any future issuance.

In May 2011, PacifiCorp issued $400 million of its 3.85% First Mortgage Bonds due June 15, 2021. The net proceeds were used to fund capital expenditures, repay short-term debt and for general corporate purposes.

PacifiCorp made scheduled repayments on long-term debt totaling $587 million and $15 million during the years ended December 31, 2011 and 2010, respectively.

As of December 31, 2011, PacifiCorp had $601 million of letters of credit providing credit enhancement and liquidity support for variable-rate tax-exempt bond obligations totaling $587 million plus interest. These letters of credit were fully available at December 31, 2011 and expire periodically through November 2012.

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, 2011, PacifiCorp estimated it would be able to issue up to $8.2 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 debt 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.

*Common Shareholder's Equity*

In January 2012, PacifiCorp declared a dividend of $50 million, which was paid to PPW Holdings in February 2012.

In January 2011, PacifiCorp declared a dividend of $275 million, which was paid to PPW Holdings in February 2011.

In March 2011, PacifiCorp declared a dividend of $275 million, which was paid to PPW Holdings in April 2011.

Cash capital contributions from MEHC were $100 million and $125 million during the years ended December 31, 2010 and 2009, respectively.

*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.

Under existing authoritative accounting guidance, such as guidance pertaining to consolidations and leases, 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 under financing agreements and 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 has available a variety of sources of liquidity and capital resources, both internal and external, including net cash flows from operating activities, 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 market, including the condition of the utility industry in general.

*Capital Expenditures*

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; outcomes of regulatory proceedings; 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. Prudently incurred expenditures for compliance-related items, such as pollution-control technologies, replacement generation, hydroelectric relicensing, hydroelectric decommissioning and associated operating costs are generally incorporated into PacifiCorp's rates.

PacifiCorp estimates that it will spend approximately $4.8 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.

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

| | 2012 | 2013 | 2014 |
|---|---|---|---|
| **Forecasted capital expenditures[(1)]:** | | | |
| Generation development | $ 308 | $ 415 | $ 400 |
| Transmission system investment | 296 | 418 | 491 |
| Environmental | 166 | 227 | 264 |
| Other | 728 | 518 | 576 |
| Total | $ 1,498 | $ 1,578 | $ 1,731 |

(1) Includes amounts for expenditures accrued but not yet paid and excludes amounts for non-cash equity AFUDC.

The capital expenditure estimate for generation development projects primarily consists of construction of Lake Side 2 adjacent to the existing Lake Side generating facility that is expected to be placed in service in 2014, and initial development and construction of another combined-cycle combustion turbine natural gas-fueled generating facility planned to be placed in service in 2016.

The capital expenditure estimate for transmission system investment includes projects associated with the Energy Gateway Transmission Expansion Program totaling $905 million, including the following estimated costs:

- $245 million for the 100-mile high-voltage transmission line being built between the Mona substation in central Utah and the Oquirrh substation in the Salt Lake Valley. A 65-mile segment of the Mona to Oquirrh transmission project will be a single-circuit 500-kV transmission line, while the remaining 35-mile segment will be a double-circuit 345-kV transmission line. The project is estimated to cost $374 million and is expected to be placed in service in 2013.

- $288 million for the 160-mile single-circuit 345-kV transmission line being built between the Sigurd Substation in central Utah and the Red Butte Substation in southwest Utah. The Sigurd to Red Butte project is estimated to cost $380 million and is expected to be placed in service in 2015.

- $372 million for other segments associated with the Energy Gateway Transmission Expansion Program that are expected to be placed in service through 2021, depending on siting, permitting and construction schedules.

The capital expenditure estimate for environmental projects includes emissions control equipment to meet anticipated air quality and visibility targets, including the reduction of sulfur dioxide, nitrogen oxides and particulate matter emissions. This estimate includes the installation of new or the replacement of existing emissions control equipment at a number of units at several of PacifiCorp's coal-fueled generating facilities.

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

## Obligations and Commitments

*Contractual Obligations*

PacifiCorp has contractual cash obligations that may affect its consolidated financial condition. The following table summarizes PacifiCorp's material contractual cash obligations as of December 31, 2011 (in millions):

| | Payments Due By Periods | | | | |
|---|---|---|---|---|---|
| | 2012 | 2013-2014 | 2015-2016 | 2017 and After | Total |
| Long-term debt, including interest: | | | | | |
| Fixed-rate obligations | $ 344 | $ 1,067 | $ 615 | $ 9,562 | $ 11,588 |
| Variable-rate obligations[1] | 4 | 87 | 170 | 404 | 665 |
| Short-term debt, including interest | 688 | — | — | — | 688 |
| Capital leases, including interest | 7 | 20 | 14 | 80 | 121 |
| Operating leases and easements | 11 | 16 | 5 | 44 | 76 |
| Asset retirement obligations | 20 | 17 | 27 | 245 | 309 |
| Power purchase agreements[2]: | | | | | |
| Electricity commodity contracts | 160 | 79 | 36 | 121 | 396 |
| Electricity capacity contracts | 74 | 143 | 126 | 280 | 623 |
| Electricity mixed contracts | 11 | 14 | 16 | 46 | 87 |
| Transmission | 108 | 182 | 116 | 702 | 1,108 |
| Fuel purchase agreements[2]: | | | | | |
| Natural gas supply and transportation | 63 | 50 | 48 | 253 | 414 |
| Coal supply and transportation | 614 | 1,182 | 854 | 2,137 | 4,787 |
| Other purchase obligations | 582 | 310 | 26 | 101 | 1,019 |
| Other long-term liabilities[3] | 59 | 11 | 6 | 57 | 133 |
| Total contractual cash obligations | $ 2,745 | $ 3,178 | $ 2,059 | $ 14,032 | $ 22,014 |

(1) Consists of principal and interest for tax-exempt bond obligations with interest rates scheduled to reset periodically prior to maturity. Future variable interest rates are set at December 31, 2011 rates. Refer to "Interest Rate Risk" in Item 7A of this Form 10-K for additional discussion related to variable-rate liabilities.

(2) 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.

(3) 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 2012 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.

## Regulatory Matters

PacifiCorp is subject to comprehensive regulation. In addition to the discussion contained herein regarding regulatory matters, refer to Item 1 of this Form 10-K for further discussion regarding PacifiCorp's general regulatory framework.

*State Regulatory Matters*

*Utah*

In March 2009, PacifiCorp filed for an ECAM with the UPSC. The filing recommended that the UPSC adopt the mechanism to recover the difference between base net power costs set in the next Utah general rate case and actual net power costs. In July 2010, the UPSC issued an order approving a stipulation that would establish deferred accounts for both net power costs and REC revenues in excess of the levels currently included in rates, subject to the UPSC's final determination of the ratemaking treatment of the deferrals. In December 2010, the UPSC approved a separate stipulation that provided a $3 million monthly credit to customers effective January 1, 2011 to be applied toward the UPSC's final decision. In March 2011, the UPSC issued its final order approving the use of an EBA in Utah to begin at the conclusion of the general rate case described below. Under the EBA, which has been established as a four year pilot program, 70% of any difference between actual net power costs incurred and the amount of net power costs recovered through base rates are deferred during the calendar year. PacifiCorp must then file by March 15 of the following year to initiate collection or refund of the deferred balance. In April 2011, PacifiCorp filed a petition with the UPSC for clarification and reconsideration of certain aspects of the EBA order, including reconsideration of the UPSC's decision to exclude financial swaps from the EBA, which was granted in May 2011.

In January 2011, PacifiCorp filed a general rate case with the UPSC requesting a rate increase of $232 million, or an average price increase of 14%. In June 2011, PacifiCorp filed its rebuttal testimony with the UPSC reducing the requested rate increase to $188 million, or an average price increase of 11%. In July 2011, PacifiCorp filed a settlement with the UPSC, which was approved by the UPSC in August 2011 and resulted in a $117 million rate increase, or an average price increase of 7% effective September 21, 2011. The settlement resolved all major dockets outstanding before the UPSC. Under the terms of the settlement, financial swaps are included in the EBA and a collaborative process with Utah stakeholders may result in future modifications to PacifiCorp's risk management and hedging policies. The settlement also concluded the ratemaking treatment of deferred accounts for net power costs and estimated sales of RECs in excess of the levels included in rates since the 2009 general rate case. The settlement provides for $60 million of net power costs in excess of amounts included in base rates to be recovered from Utah customers over a three-year period beginning June 1, 2012, without carrying charges. The settlement also provides for a $33 million credit to customers related to sales of RECs that substantially occurred in prior years and that will be credited to Utah customers over a period of approximately nine months beginning September 21, 2011, plus carrying charges. The settlement also establishes a balancing account for prospective REC sales. The settlement stipulation defers decisions regarding the ratemaking treatment associated with the Klamath hydroelectric system's four mainstem dams and relicensing and settlement costs as described in Note 8 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

In November 2011, PacifiCorp filed with the UPSC to decrease its DSM cost recovery tariff in Utah by 1% of a customer's eligible monthly charges. In January 2012, the UPSC approved an all-party stipulation to reduce the DSM surcharge by 0.4% effective February 1, 2012. In addition, approximately $5 million will be credited to customers over a one-year period beginning June 1, 2012.

In February 2012, PacifiCorp filed a general rate case with the UPSC requesting a rate increase of $172 million, or an average price increase of 10%.

*Oregon*

In March 2011, PacifiCorp made its initial filing for the annual TAM with the OPUC for an annual increase of $62 million to recover the anticipated net power costs forecasted for calendar year 2012. In July 2011, PacifiCorp filed updated net power costs, reflecting an increase in the overall request to $63 million. In August 2011, PacifiCorp filed its surrebuttal testimony in the TAM proceeding decreasing the overall request to $59 million due to a reduction in forecasted net power costs. In September 2011, PacifiCorp reached a settlement with several parties, including the OPUC staff, to reduce the requested increase to $51 million, or an average price increase of 4%, subject to final net power cost updates in November 2011. In November 2011, the OPUC approved the overall rate increase of $51 million, or an average price increase of 4%. The new rates were effective January 1, 2012.

In October 2010, PacifiCorp filed its 2009 tax report under SB 408. In January 2011, PacifiCorp entered into a stipulation with the OPUC staff and the Citizens' Utility Board of Oregon, whereby PacifiCorp, the OPUC staff and the Citizens' Utility Board of Oregon agreed to a surcharge of $13 million, plus interest. In April 2011, the OPUC issued an order adopting the stipulation without significant modification. The $13 million, plus interest, was recorded in earnings in the second quarter of 2011 and is being collected over a one-year period that began in June 2011.

In May 2011, Oregon Senate Bill 967 ("SB 967") was enacted into law. SB 967 repealed and replaced SB 408, and as a result, PacifiCorp will no longer be required to file tax reports under SB 408. Among other matters, SB 967 directs the OPUC to consider the income tax component of rates when conducting ratemaking proceedings. The enactment of SB 967 did not impact PacifiCorp's consolidated financial results.

*Wyoming*

In April 2010, PacifiCorp filed an application with the WPSC requesting approval of a new ECAM to replace the existing PCAM. The PCAM concluded with the final deferral of net power costs in November 2010 and collection through March 2012. In February 2011, the WPSC issued an order approving an ECAM effective December 1, 2010, under which 70% of any difference between actual net power costs incurred and the amount of net power costs recovered through base rates, subject to certain other adjustments, are deferred as incurred during the calendar year. PacifiCorp must then file by March 15 of the following year to initiate collection or refund of the deferred balance beginning June 1.

In November 2010, PacifiCorp filed a general rate case with the WPSC requesting a rate increase of $98 million, or an average price increase of 17%. In May 2011, PacifiCorp filed its rebuttal testimony with the WPSC reducing the requested rate increase to $80 million. In June 2011, the WPSC approved a multi-party stipulation resulting in an annual rate increase of $62 million, or an average price increase of 11%. The stipulation also established a surcredit and a balancing account to pass on to or collect from customers any difference between the amount of the REC sales established in the surcredit and actual REC sales. The surcredit will be established annually based on PacifiCorp's forecasted REC sales, and the difference between the surcredit and actual REC sales will be tracked in the balancing account. For 2011, the surcredit was set at $17 million, or a 3% reduction. The rates were effective September 22, 2011.

In February 2011, PacifiCorp filed its final PCAM application with the WPSC requesting recovery of $16 million in deferred net power costs over the 12-month period ending March 31, 2012. PacifiCorp requested and received approval from the WPSC to implement an $11 million interim rate increase over the $5 million reflected in the tariff to be effective from April 1, 2011 until the WPSC issues a final order. In September 2011, PacifiCorp reached an agreement with intervening parties and filed a stipulation with the WPSC to recover $14 million in deferred net power costs. In October 2011, the WPSC approved the stipulation with an effective date of November 1, 2011.

In December 2011, PacifiCorp filed a general rate case with the WPSC requesting an annual increase of $63 million, or an average price increase of 10%. If approved by the WPSC, the new rates are expected to be effective October 9, 2012.

*Washington*

In May 2010, PacifiCorp filed a general rate case with the WUTC requesting an annual increase of $57 million, or an average price increase of 21%. In November 2010, the requested annual increase was reduced to $49 million, or an average price increase of 18%. In March 2011, the WUTC issued a final order and clarification letter approving an annual increase of $33 million, or an average price increase of 12%, reduced in the first year by a customer bill credit of $5 million, or 2%, related to the sale of RECs expected during the twelve-month period ended March 31, 2012, as well as requiring PacifiCorp to submit additional information to the WUTC regarding the sales of RECs. The new rates were effective in April 2011. Although both PacifiCorp and the WUTC staff filed petitions for reconsideration of various items on the final order, the WUTC denied the petitions for reconsideration. In May 2011, PacifiCorp submitted to the WUTC the additional information required by the March 2011 order regarding PacifiCorp's proceeds from sales of RECs for the period January 1, 2009 forward and a detailed proposal for a tracking mechanism for proceeds of RECs. Intervening parties and WUTC staff are proposing that PacifiCorp refund to customers the amount of REC sales in excess of the amount included in base rates since January 1, 2009. Initial and reply briefs from all parties were filed in November 2011. Oral arguments were held before the WUTC in January 2012 and an order is expected during the first quarter of 2012.

In July 2011, PacifiCorp filed a general rate case with the WUTC requesting an annual increase of $13 million, or an average price increase of 4%, with an effective date no later than June 1, 2012. In February 2012, the parties to the proceeding filed a settlement agreement with the WUTC reflecting an annual increase of $5 million, or an average price increase of 2%. A hearing on the settlement agreement is scheduled for March 2012.

*Idaho*

In May 2010, PacifiCorp filed a general rate case with the IPUC requesting an annual increase of $28 million, or an average price increase of 14%. In November 2010, the requested annual increase was reduced to $25 million, or an average price increase of 12%. In December 2010, the IPUC issued an interim order approving an annual increase of $14 million, or an average price increase of 7% with an effective date of December 28, 2010. In February 2011, the IPUC issued its final order with no revisions to the December 2010 increase. In March 2011, PacifiCorp petitioned the IPUC seeking reconsideration or rehearing on certain aspects of the order, including the IPUC's conclusion that 27% of PacifiCorp's Populus to Terminal transmission line investment is not currently used and useful and should be carried as plant held for future use. The Idaho-allocated share of 27% of the investment is approximately $13 million. In April 2011, the IPUC issued an order, accepting in part and rejecting in part, PacifiCorp's motion for reconsideration, resulting in no significant changes to the IPUC's initial order. In May 2011, PacifiCorp filed an appeal of the Populus to Terminal decision to the Idaho Supreme Court requesting a determination on the legality of the IPUC's decision to exclude 27% of the Populus to Terminal line as a result of its conclusion that the line is not fully used and useful. As a result of the general rate case settlement process discussed below, PacifiCorp joined in a motion filed with the Idaho Supreme Court in October 2011, to stay the procedural schedule associated with the appeal until January 30, 2012, and the Idaho Supreme Court granted the motion. The matter was settled in the general rate case described below and the appeal was dismissed.

In May 2011, PacifiCorp filed a general rate case with the IPUC requesting an annual increase of $33 million, or an average price increase of 15%. In October 2011, a settlement was reached with the majority of parties in the case providing for a two-year agreement to increase rates by $17 million each year effective January 1, 2012 and January 1, 2013, representing average price increases of 8% and 7%, respectively. The settlement also resolved the dispute over the 27% of PacifiCorp's Populus to Terminal investment, providing for recovery of PacifiCorp's investment beginning on or after January 1, 2014. In January 2012, PacifiCorp received an order from the IPUC approving the settlement.

In February 2011, PacifiCorp filed an ECAM application with the IPUC requesting recovery of $13 million in deferred net power costs. In March 2011, the IPUC issued an order approving recovery of $10 million beginning April 1, 2011 and the remaining $3 million beginning in 2012.

In February 2012, PacifiCorp filed an ECAM application with the IPUC requesting recovery of $18 million in deferred net power costs through an increase to the current ECAM surcharge rate established in 2011. If approved, the new rates will be effective April 1, 2012.

*California*

In October 2011, PacifiCorp filed its annual PTAM attrition adjustment with the CPUC. The filing requested an increase of $1 million, or an average price increase of 1%. The CPUC approved the new rates, which became effective January 1, 2012.

In January 2012, PacifiCorp and the California Division of Ratepayer Advocates filed a joint motion for commission adoption and approval of a written stipulation for an overall rate increase of $2 million, or an average price increase of 2%, under the ECAC. If approved by the CPUC, PacifiCorp expects that the new rates will be effective in the first quarter of 2012.

*FERC*

As a result of a 2007 multi-party settlement with the FERC regarding long-term shared usage, coordinated operation and maintenance, and planning of certain 500-kV transmission lines, PacifiCorp agreed to file a Federal Power Act Section 205 rate change filing for its system-wide transmission service rates no later than June 1, 2011. In May 2011, PacifiCorp filed its Federal Power Act Section 205 rate case seeking to modify its transmission and ancillary services rates and adopt a formula transmission rate. In August 2011, the FERC issued an order accepting PacifiCorp's filing and allowing the proposed rates to become effective December 25, 2011, subject to refund. Billing at the new rates commenced in early 2012. The FERC established settlement proceedings to encourage the parties to reach agreement on final rates. If a settlement is not reached, hearings will be held before the FERC to arrive at final approved rates. Settlement discussions are underway with the parties to the case.

## Environmental Laws and Regulations

PacifiCorp is subject to federal, state and local laws and regulations regarding air and water quality, RPS, emissions performance standards, climate change, coal combustion byproduct disposal, hazardous and solid waste disposal, protected species and other environmental matters that have the potential to impact PacifiCorp's current and future operations. In addition to imposing continuing compliance obligations, these laws and regulations provide regulators with the authority to levy substantial penalties for noncompliance including fines, injunctive relief and other sanctions. These laws and regulations are administered by the EPA and various other state and local agencies. All such laws and regulations are subject to a range of interpretation, which may ultimately be resolved by the courts. Environmental laws and regulations continue to evolve, and PacifiCorp is unable to predict the impact of the changing laws and regulations on its operations and consolidated financial results. PacifiCorp believes it is in material compliance with all applicable laws and regulations. Refer to "Future Uses of Cash" for discussion of PacifiCorp's forecasted environmental-related capital expenditures.

### *Clean Air Standards*

The Clean Air Act is a federal law, administered by the EPA that provides a framework for protecting and improving the nation's air quality and controlling sources of air emissions. The implementation of new standards is generally outlined in SIPs. SIPs, which are a collection of regulations, programs and policies to be followed, vary by state and are subject to public hearings and EPA approval. Some states may adopt additional or more stringent requirements than those implemented by the EPA. The major Clean Air Act programs, most directly affecting PacifiCorp's operations, are described below.

#### *National Ambient Air Quality Standards*

Under the authority of the Clean Air Act, the EPA sets minimum national ambient air quality standards for six principal pollutants, consisting of carbon monoxide, lead, nitrogen oxides, particulate matter, ozone and sulfur dioxide, considered harmful to public health and the environment. 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 that are determined to contribute to the nonattainment are required to reduce emissions. Most air quality standards require measurement over a defined period of time to determine the average concentration of the pollutant present.

In December 2009, the EPA designated the Utah counties of Davis and Salt Lake, as well as portions of Box Elder, Cache, Tooele, Utah and Weber counties, to be in nonattainment of the fine particulate matter standard. This designation has the potential to impact PacifiCorp's Lake Side and Gadsby generating facilities, depending on the requirements to be established in the Utah SIP. The impact, if any, on PacifiCorp's generating facilities is not anticipated to be significant.

In January 2010, the EPA proposed a rule to strengthen the national ambient air quality standard for ground level ozone. The proposed rule arose out of legal challenges claiming that a March 2008 rule that reduced the standard from 80 parts per billion to 75 parts per billion was not strict enough. The new rule proposed a standard between 60 and 70 parts per billion. In September 2011, the President requested that the EPA withdraw the proposed ozone standard and allow the review of the standards to proceed through the regularly scheduled review in 2013. The EPA is, therefore, proceeding with implementation of the March 2008 ozone standards and, in December 2011, issued its response to states' recommendations on area attainment designations. Part of the EPA's response recommended that the Upper Green River Basin Area in Wyoming, including all of Sublette and portions of Lincoln and Sweetwater Counties, be designated as nonattainment for the March 2008 ozone standard. While PacifiCorp's Jim Bridger plant is located in Sweetwater County, it is not in the portion proposed for designation as nonattainment and is not expected to be impacted by the proposed designation. The EPA also published a proposed consent decree in the Federal Register in December 2011, requiring it to sign final designations for the March 2008 ozone standard by May 31, 2012.

In January 2010, the EPA finalized a one-hour air quality standard for nitrogen dioxide at 0.10 part per million. The EPA published final designations that are effective February 29, 2012, indicating that based on air quality monitoring data, all areas of the country are designated as "unclassifiable/attainment" for the 2010 nitrogen dioxide national ambient air quality standard.

In June 2010, the EPA finalized a new national ambient air quality standard for sulfur dioxide. Under the new rule, the existing 24-hour and annual standards for sulfur dioxide, which were 140 parts per billion measured over 24 hours and 30 parts per billion measured over an entire year, were replaced with a new one-hour standard of 75 parts per billion. The new rule will utilize a three-year average to determine attainment. The rule will utilize source modeling, in addition to the installation of ambient monitors where sulfur dioxide emissions impact populated areas, with new monitors required to be placed in service no later than January 2013. Attainment designations are due by June 2012, with SIPs due by 2014 and final attainment demonstrations by August 2017.

As new, more stringent standards are adopted, the number of counties designated as nonattainment areas is likely to increase. Businesses operating in newly designated nonattainment counties could face increased regulation and costs to monitor or reduce emissions. For instance, existing major emissions sources may have to install reasonably available control technologies to achieve certain reductions in emissions and undertake additional monitoring, recordkeeping and reporting. The construction or modification of facilities that are sources of emissions could become more difficult in nonattainment areas. Until additional monitoring and modeling is conducted, the impacts on PacifiCorp cannot be determined.

*Mercury and Air Toxics Standards*

The Clean Air Mercury Rule ("CAMR"), issued by the EPA in March 2005, was the United States' first attempt to regulate mercury emissions from coal-fueled generating facilities through the use of a market-based cap-and-trade system. The CAMR, which mandated emissions reductions of approximately 70% by 2018, was overturned by the United States Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") in February 2008. In March 2011, the EPA proposed a new rule that would require coal-fueled generating facilities to reduce mercury emissions and other hazardous air pollutants through the establishment of "Maximum Achievable Control Technology" standards rather than a cap-and-trade system. The final rule, MATS, was released by the EPA in December 2011 and published in the Federal Register on February 16, 2012, and requires that new and existing coal-fueled facilities achieve emission standards for mercury, acid gases and other non-mercury hazardous air pollutants. Existing sources are required to comply with the new standards within three years after the rule is final, with individual sources granted an additional year to complete installation of controls if approved by the permitting authority. While the final MATS continues to be reviewed by PacifiCorp, PacifiCorp believes that its emissions reduction projects completed to date or currently permitted or planned for installation, including scrubbers, baghouses and electrostatic precipitators are consistent with the EPA's MATS and will support PacifiCorp's ability to comply with the final rule's standards for acid gases and non-mercury metallic hazardous air pollutants. PacifiCorp will be required to take additional actions to reduce mercury emissions through the installation of controls or use of sorbent injection at certain of its coal-fueled generating facilities and otherwise comply with the final rule's standards and is evaluating whether or not to close certain units. Incremental costs to install and maintain mercury emissions control equipment at PacifiCorp's coal-fueled generating facilities and any requirements to shut down generating facilities will increase the cost of providing service to customers.

*Regional Haze*

The EPA has initiated a regional haze program intended to improve visibility in designated federally protected areas ("Class I areas"). Some of PacifiCorp's coal-fueled generating facilities in Utah and Wyoming meet the threshold applicability criteria to be eligible units 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 towards achieving natural visibility conditions in Class I areas by requiring emissions controls, known as best available retrofit technology, on sources constructed between 1962 and 1977 with emissions that are anticipated to cause or contribute to impairment of visibility. Utah submitted its most recent regional haze SIP amendments in 2011 and suggested that the emissions reduction projects planned by PacifiCorp are sufficient to meet its initial emissions reduction requirements. In September 2011, PacifiCorp received a Section 114 request for information from the EPA Region VIII requiring PacifiCorp to submit a five-factor best available retrofit technology analysis for PacifiCorp's Hunter Units 1 and 2 and the Huntington generating facility in Utah within 30 days based on the EPA's assertion that Utah failed to submit such an analysis. PacifiCorp responded to the request in November 2011 and indicated it would work with the Utah Division of Air Quality to complete the requested analysis which, based on a schedule proposed by Utah to the EPA, will be part of a process to conclude with a submittal to the EPA in February 2013. Wyoming submitted its regional haze SIP to the EPA in January 2011. The EPA is currently under a consent decree to issue a proposed decision on the Wyoming SIP by May 15, 2012, and a final decision by October 15, 2012. PacifiCorp believes that its planned emissions reduction projects will satisfy the regional haze requirements in Utah and Wyoming. It is possible that additional controls may be required after the respective SIPs have been considered by the EPA or that the timing of installation of planned controls could change.

The EPA's rejection of regional haze SIPs based on the state's selection of less stringent controls than the EPA believes are warranted has resulted in lawsuits being filed by states and affected entities. Cases are pending before the Tenth Circuit Court of Appeals by New Mexico and Oklahoma and additional cases are likely to be filed.

*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 (a) beginning construction of a new major stationary source of a regulated pollutant or (b) 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 require 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 an analysis to determine the best available control technology and evaluate the most effective emissions controls after consideration of a number of factors. Violations of NSR regulations, which may be alleged by the EPA, states, environmental groups and others, potentially subject a company to material fines and other sanctions and remedies, including installation of enhanced pollution controls and funding of supplemental environmental projects.

Numerous changes have been proposed to the NSR rules and regulations over the last several years. In addition to the proposed changes, differing interpretations by the EPA and the courts create risk and uncertainty for entities when seeking permits for new projects and installing emissions controls at existing facilities under NSR requirements. PacifiCorp monitors these changes and interpretations to ensure permitting activities are conducted in accordance with the applicable requirements.

As part of an industry-wide investigation to assess compliance with the NSR and PSD provisions, the EPA has requested information and supporting documentation from numerous utilities regarding their capital projects for various coal-fueled generating facilities. A NSR enforcement case against an unrelated utility has been decided by the United States Supreme Court, holding that an increase in the annual emissions of a generating facility, when combined with a modification (i.e., a physical or operational change), may trigger NSR permitting. Between 2001 and 2003, PacifiCorp responded to requests for information relating to its capital projects at its coal-fueled generating facilities. PacifiCorp engaged in periodic discussions with the EPA over several years regarding PacifiCorp's historical projects and their compliance with NSR and PSD provisions. In September 2011, PacifiCorp received a letter from the EPA concluding these discussions. PacifiCorp cannot predict the next steps in this process and 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.

*Climate Change*

In April 2011, the United States House of Representatives voted 255-177 on a bill (H.R. 910) that would prevent the EPA from regulating GHG emissions. No action has been taken by the Senate on the bill. While significant measures to regulate GHG emissions at the federal level were considered by the United States Congress in 2010, comprehensive climate change legislation has not been adopted. International discussions regarding climate change continue to be held periodically, but agreement has not been reached on how nations will address future climate change commitments upon the expiration of the Kyoto Protocol in December 2012.

In December 2009, the EPA published its findings that GHG threaten the public health and welfare and is pursuing regulation of GHG emissions under the Clean Air Act. Additionally, in May 2010, the EPA issued the GHG "Tailoring Rule" to address permitting requirements for GHG after determining that GHG are subject to regulation and would trigger Clean Air Act permitting requirements for stationary sources beginning in January 2011. Numerous lawsuits have been filed on both the EPA's endangerment finding and the tailoring rule and are pending in the D.C. Circuit with arguments scheduled to take place in February 2012.

While the debate continues at the federal and international level over the direction of climate change policy, several states have developed or are developing state-specific laws or regional initiatives to report or mitigate GHG emissions. In addition, governmental, non-governmental and environmental organizations have become more active in pursuing climate change related litigation under existing laws.

California mandatory GHG reporting requirements began with 2008 emissions and PacifiCorp has reported its GHG emissions annually since their inception. In September 2009, the EPA issued its final rule regarding mandatory reporting of GHG beginning January 1, 2010. Under GHG Reporting, suppliers of fossil fuels, manufacturers of vehicles and engines, and facilities that emit 25,000 metric tons or more per year of GHG are required to submit annual reports to the EPA. PacifiCorp is subject to this requirement and submitted its first report prior to September 30, 2011. The EPA released the 2010 GHG emissions reports in January 2012.

In the absence of comprehensive climate legislation or regulation, PacifiCorp has continued to invest in lower- and non-carbon generating resources and to operate in an environmentally responsible manner. Examples of PacifiCorp's significant investments in programs and facilities that will mitigate its GHG emissions include:

- PacifiCorp owns the second largest portfolio of wind-powered generating capacity in the United States among rate-regulated utilities. As of December 31, 2011, PacifiCorp owned 1,031 MW of operating wind-powered generating capacity. PacifiCorp has invested $2.1 billion in wind-powered generating facilities and has power purchase agreements with 749 MW of wind-powered generating capacity.

- PacifiCorp owns 1,145 MW of hydroelectric generating capacity.

- PacifiCorp's Energy Gateway Transmission Expansion Program represents a plan to build approximately 2,000 miles of new high-voltage transmission lines with an estimated cost exceeding $6 billion. The plan includes several transmission line segments that will: (a) address customer load growth; (b) improve system reliability; (c) reduce transmission system constraints; (d) provide access to diverse generation resources, including renewable resources; and (e) improve the flow of electricity throughout PacifiCorp's six-state service area.

- PacifiCorp has offered customers a comprehensive set of DSM programs for more than 20 years. The programs assist customers to manage the timing of their usage, as well as to reduce overall energy consumption, resulting in lower utility bills.

- PacifiCorp has installed and upgraded emissions control equipment at certain of its coal-fueled generating facilities to reduce emissions of sulfur dioxide and nitrogen oxides.

The impact of potential federal, regional, state and international accords, legislation, regulation, or judicial proceedings related to climate change cannot be quantified in any meaningful range at this time. New requirements limiting GHG emissions could have a material adverse impact on PacifiCorp, the United States and the global economy. Companies and industries with higher GHG emissions, such as utilities with significant coal-fueled generating facilities, will be subject to more direct impacts and greater financial and regulatory risks. The impact is dependent on numerous factors, none of which can be meaningfully quantified at this time. These factors include, but are not limited to, the magnitude and timing of GHG emissions reduction requirements; the design of the requirements; the cost, availability and effectiveness of emissions control technology; the price, distribution method and availability of offsets and allowances used for compliance; government-imposed compliance costs; and the existence and nature of incremental cost recovery mechanisms. Examples of how new requirements may impact PacifiCorp include:

- Additional costs may be incurred to purchase required emissions allowances under any market-based cap-and-trade system in excess of allocations that are received at no cost. These purchases would be necessary until new technologies could be developed and deployed to reduce emissions or lower carbon generation is available;

- Acquiring and renewing construction and operating permits for new and existing generating facilities may be costly and difficult;

- Additional costs may be incurred to purchase and deploy new generating technologies;

- Costs may be incurred to retire existing coal-fueled generating facilities before the end of their otherwise useful lives or to convert them to burn fuels, such as natural gas or biomass, that result in lower emissions;

- Operating costs may be higher and generating unit outputs may be lower;

- Higher interest and financing costs and reduced access to capital markets may result to the extent that financial markets view climate change and GHG emissions as a business risk; and

- PacifiCorp's electric transmission and retail sales may be impacted in response to changes in customer demand and requirements to reduce GHG emissions.

The impact of events or conditions caused by climate change, whether from natural processes or human activities, could vary widely, from highly localized to worldwide, and the extent to which a utility's operations may be affected is uncertain. Climate change may cause physical and financial risk through, among other things, sea level rise, changes in precipitation and extreme weather events. Consumer demand for energy may increase or decrease, based on overall changes in weather and as customers promote lower energy consumption through the continued use of energy efficiency programs or other means. 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 generating portfolio. These issues may have a direct impact on the costs of electricity production and increase the price customers pay or their demand for electricity.

*International Accords*

Under the United Nations Framework Convention on Climate Change adopted in 1992, members of the convention meet periodically to discuss international responses to climate change. To date, the United States has not made a binding reduction commitment as a result of these international discussions.

*Federal Legislation*

Legislation introduced in the 112th Congress has been focused on repeal or delay of the EPA's ability to regulate GHG emissions. There is currently no federal legislation pending to regulate GHG emissions.

*GHG Tailoring Rule*

The EPA finalized the GHG "Tailoring Rule" in May 2010 requiring new or modified sources of GHG emissions with increases of 75,000 or more tons per year of total GHG to determine the best available control technology for their GHG emissions beginning in January 2011. New or existing major sources will also be subject to Title V operating permit requirements for GHG. Beginning July 1, 2011 through June 30, 2013, new construction projects that emit GHG emissions of at least 100,000 tons per year and modifications of existing facilities that increase GHG emissions by at least 75,000 tons per year will be subject to permitting requirements and facilities that were previously not subject to Title V permitting requirements will be required to obtain Title V permits if they emit at least 100,000 tons per year of carbon dioxide equivalents. Several legal challenges to the GHG Tailoring Rule have been filed in the D.C. Circuit. The EPA issued a GHG best available control technology guidance document in November 2010 in an effort to provide permitting authorities guidance on how to conduct a best available control technology review for GHG.

PacifiCorp's permitting of certain existing generating facilities to install emissions reduction equipment to comply with the Regional Haze Rules assessed the impacts of the projects on GHG emissions under the GHG Tailoring Rule. No GHG emissions limit was included in the permits. However, Lake Side 2 was subject to a best available control technology review and the permit includes a limit for carbon dioxide equivalent emissions. To date, permitting authorities implementing the GHG Tailoring Rule have included efficiency improvements to demonstrate compliance with best available control technology for GHG, as well as requiring emissions limits for GHGs in permits; as such, the impacts of the Tailoring Rule on PacifiCorp have not been material.

*GHG New Source Performance Standards*

Under the Clean Air Act, the EPA may establish emissions standards that reflect the degree of emissions reductions achievable through the best technology that has been demonstrated, taking into consideration the cost of achieving those reductions and any non-air quality health and environmental impact and energy requirements. The EPA entered into a settlement agreement with a number of parties, including certain state governments and environmental groups, in December 2010 to promulgate emissions standards covering GHG by September 30, 2011, as amended, and issue final regulations by May 26, 2012. However, in mid-September, the EPA indicated it would not meet the September 30, 2011 deadline to promulgate the standards and it has not yet established a new schedule for issuing the proposed rules. It is unclear what standards the EPA will establish for new and modified sources or what the guidelines will be for existing sources. Until the standards are proposed and finalized, the impact on PacifiCorp cannot be determined.

*Regional and State Activities*

Several states have promulgated or otherwise participate in state-specific or regional laws or initiatives to report or mitigate GHG emissions. These are expected to impact PacifiCorp and include:

- The Western Climate Initiative was established as a comprehensive regional effort to reduce GHG emissions by 15% below 2005 levels by 2020 through a cap-and-trade program that includes the electricity sector. The Western Climate Initiative initially included the states of California, Montana, New Mexico, Oregon, Utah and Washington and the Canadian provinces of British Columbia, Manitoba, Ontario and Quebec. However, only California, British Columbia and Quebec are moving forward under the initiative, with the other states focused on efforts to design, promote and implement cost-effective policies to reduce GHG emissions and create economic opportunities.

- In October 2011, the California Air Resources Board adopted a GHG cap-and-trade program with an effective date of January 1, 2012; compliance obligations will be imposed on entities beginning in 2013. In addition, California law imposes a GHG emissions performance standard to all electricity generated within the state or delivered from outside the state that is no higher than the GHG emissions levels of a state-of-the-art combined-cycle natural gas-fueled generating facility, as well as legislation that adopts an economy-wide cap on GHG emissions to 1990 levels by 2020.

- Over the past several years, the states of California, Washington and Oregon have adopted GHG emissions performance standards for base load electrical generating resources. Under the laws in all three states, the emissions performance standards provide that emissions must not exceed 1,100 pounds of carbon dioxide per MWh. These GHG emissions performance standards generally prohibit electric utilities from entering into long-term financial commitments (e.g., new ownership investments, upgrades, or new or renewed contracts with a term of five or more years) unless any base load generation supplied under long-term financial commitments comply with the GHG emissions performance standards.

- The Washington and Oregon governors enacted legislation in May 2007 and August 2007, respectively, establishing goals for the reduction of GHG emissions in their respective states. Washington's goals seek to: (a) reduce emissions to 1990 levels by 2020; (b) reduce emissions to 25% below 1990 levels by 2035; and (c) reduce emissions to 50% below 1990 levels by 2050, or 70% below Washington's forecasted emissions in 2050. Oregon's goals seek to: (a) cease the growth of Oregon GHG emissions by 2010; (b) reduce GHG levels to 10% below 1990 levels by 2020; and (c) reduce GHG levels to at least 75% below 1990 levels by 2050. Each state's legislation also calls for state government to develop policy recommendations in the future to assist in the monitoring and achievement of these goals.

*Renewable Portfolio Standards*

The RPS described below could significantly impact PacifiCorp's consolidated 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 noncompliance.

In November 2006, Washington voters approved a ballot initiative establishing a RPS requirement for qualifying electric utilities, including PacifiCorp. The requirements are 3% of retail sales by January 1, 2012 through 2015, 9% of retail sales by January 1, 2016 through 2019 and 15% of retail sales by January 1, 2020. The WUTC has adopted final rules to implement the initiative.

In June 2007, the Oregon Renewable Energy Act ("OREA") was adopted, providing a comprehensive renewable energy policy and RPS 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.

In April 2011, the California governor signed into law Senate Bill 2 of the First Extraordinary Session that expanded the RPS to require all California retail sellers to procure an average of 20% of retail load from renewable resources by December 31, 2013, 25% by December 31, 2016 and 33% by December 31, 2020 and each year thereafter. In December 2011, the CPUC adopted a decision confirming that multi-jurisdictional utilities, such as PacifiCorp, are not subject to the percentage limits within the three categories of RPS-eligible resources established by the legislation that have been imposed on other California retail sellers. The CPUC is in the process of an extensive rulemaking to implement the new requirements under the legislation.

In March 2008, Utah's governor signed Utah Senate Bill 202. 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 DSM programs. Qualifying renewable energy sources can be located anywhere in the WECC areas, and renewable energy credits can be used.

*Water Quality Standards*

The federal Water Pollution Control Act ("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 technology-based performance standards for existing electric generating facilities that take in more than 50 million gallons of water per day. These rules were 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 remanded almost all aspects of the rule to the EPA, without addressing whether companies with cooling water intake structures were required to comply with these requirements. On appeal from the Second Circuit, in April 2009, the United States Supreme Court ruled that the EPA permissibly relied on a cost-benefit analysis in setting the national performance standards regarding "best technology available for minimizing adverse environmental impact" at cooling water intake structures and in providing for cost-benefit variances from those standards as part of the §316(b) Clean Water Act Phase II regulations. The United States Supreme Court remanded the case back to the Second Circuit to conduct further proceedings consistent with its opinion.

In March 2011, the EPA released a proposed rule under §316(b) of the Clean Water Act to regulate cooling water intakes at existing facilities. The proposed rule establishes requirements for all power generating facilities that withdraw more than two million gallons per day, based on total design intake capacity, of water from waters of the United States and use at least 25% of the withdrawn water exclusively for cooling purposes. PacifiCorp's Dave Johnston generating facility withdraws more than two million gallons per day of water from waters of the United States. PacifiCorp's Jim Bridger, Naughton, Gadsby, Hunter, Carbon and Huntington generating facilities currently utilize closed cycle cooling towers but withdraw more than two million gallons of water per day. The proposed rule includes impingement (i.e., when fish and other organisms are trapped against screens when water is drawn into a facility's cooling system) mortality standards to be met through average impingement mortality or intake velocity design criteria and entrainment (i.e., when organisms are drawn into the facility) standards to be determined on a case-by-case basis. The standards are required to be met as soon as possible after the effective date of the final rule, but no later than eight years thereafter. The rule is required to be finalized by the EPA by July 2012. Assuming the final rule is issued by July 2012, PacifiCorp's generating facilities impacted by the final rule will be required to complete impingement and entrainment studies in 2013. The costs of compliance with the cooling water intake structure rule cannot be determined until the rule is final and the prescribed studies are conducted. In the event that PacifiCorp's existing intake structures require modification, the costs are not anticipated to be significant.

*Coal Combustion Byproduct 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 and 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 the storage and disposal of coal combustion byproducts. In May 2010, the EPA released a proposed rule to regulate the management and disposal of coal combustion byproducts, presenting two alternatives to regulation under the RCRA. Under the first option, coal combustion byproducts would be regulated as special waste under RCRA Subtitle C and the EPA would establish requirements for coal combustion byproducts from the point of generation to disposition, including the closure of disposal units. Alternatively, the EPA is considering regulation under RCRA Subtitle D under which it would establish minimum nationwide standards for the disposal of coal combustion byproducts. Under both options, surface impoundments utilized for coal combustion byproducts would have to be cleaned and closed unless they could meet more stringent regulatory requirements; in addition, more stringent requirements would be implemented for new ash landfills and expansions of existing ash landfills. PacifiCorp operates 16 surface impoundments and six landfills that contain coal combustion byproducts. These ash impoundments and landfills may be impacted by the newly proposed regulation, particularly if the materials are regulated as hazardous or special waste under RCRA Subtitle C, and could pose significant additional costs associated with ash management and disposal activities at PacifiCorp's coal-fueled generating facilities. The public comment period closed in November 2010. The EPA has not indicated when the rule will be finalized and the substance of the final rule is not known. The United States House of Representatives passed H.R. 2273 in October 2011, which would regulate coal combustion byproducts under RCRA Subtitle D. A Senate bill similar to the House bill has been introduced, but action has not been taken on the bill. The impact of the proposed regulations on coal combustion byproducts cannot be determined at this time; however, PacifiCorp has begun developing surface impoundment and landfill compliance plan options to ensure that physical infrastructure decisions are aligned with the potential outcomes of the rulemaking.

*Other*

Other laws, regulations and agencies to which PacifiCorp is subject to include, but are not limited to:

- The federal Comprehensive Environmental Response, Compensation and Liability Act and similar state laws 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.

- 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.

- 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 facilities.

PacifiCorp expects that it will be allowed to recover the prudently incurred costs to comply with the environmental laws and regulations discussed above. PacifiCorp's planning efforts take into consideration the complexity of balancing factors such as: (a) pending environmental regulations and requirements to reduce emissions, address waste disposal, ensure water quality and protect wildlife; (b) avoidance of excessive reliance on any one generation technology; (c) costs and trade-offs of various resource options including energy efficiency, demand response programs and renewable generation; (d) state-specific energy policies, resource preferences and economic development efforts; (e) additional transmission investment to reduce power costs and increase efficiency and reliability of the integrated transmission system; and (f) keeping rates as affordable as possible. Due to the number of generating units impacted by environmental regulations, deferring installation of compliance-related projects is often not feasible or cost effective and places PacifiCorp at risk of not having access to necessary capital, material and labor while attempting to perform major equipment installations in a compressed timeframe concurrent with other utilities across the country. Therefore, PacifiCorp has established installation schedules with permitting agencies that coordinate compliance timeframes with construction and tie-in of major environmental compliance projects as units are scheduled off-line for planned maintenance outages; these coordinated efforts help reduce costs associated with replacement power and maintain system reliability.

**Collateral and Contingent Features**

Debt and preferred securities of PacifiCorp are rated by 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. As of December 31, 2011, PacifiCorp's credit ratings for its senior secured and senior unsecured debt from the three recognized credit rating agencies were investment grade.

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 the 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 ratings 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.

In accordance with industry practice, certain wholesale energy agreements, including derivative contracts, contain provisions that require PacifiCorp to maintain specific credit ratings on its unsecured debt from one or more of the three recognized credit rating agencies. These agreements may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance" in the event of a material adverse change in PacifiCorp's creditworthiness. These rights can vary by contract and by counterparty. If all credit-risk-related contingent features or adequate assurance provisions for these agreements, including derivative contracts, had been triggered as of December 31, 2011, PacifiCorp would have been required to post $282 million of additional collateral. PacifiCorp's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation, or other factors. Refer to Note 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for a discussion of PacifiCorp's collateral requirements specific to PacifiCorp's derivative contracts.

In July 2010, the President signed into law the Dodd-Frank Reform Act. The Dodd-Frank Reform Act reshapes financial regulation in the United States by creating new regulators, regulating new markets and firms and providing new enforcement powers to regulators. Virtually all major areas of the Dodd-Frank Reform Act, including collateral requirements on derivative contracts, are the subject of regulatory interpretation and implementation rules requiring rulemaking proceedings, some of which have been completed and others that are expected to be finalized in 2012.

PacifiCorp is a party to derivative contracts, including over-the-counter derivative contracts. The Dodd-Frank Reform Act provides for extensive new regulation of over-the-counter derivative contracts and certain market participants, including imposition of mandatory clearing, exchange trading, capital and margin requirements for "swap dealers" and "major swap participants." The Dodd-Frank Reform Act provides certain exemptions from these regulations for commercial end-users that use derivatives to hedge and manage the commercial risk of their businesses. Although PacifiCorp generally does not enter into over-the-counter derivative contracts for purposes unrelated to hedging of commercial risk and does not believe it will be considered a swap dealer or major swap participant, the outcome of the rulemaking proceedings cannot be predicted and, therefore, the impact of the Dodd-Frank Reform Act on PacifiCorp's consolidated financial results cannot be determined at this time.

## 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 1.0. Management believes that PacifiCorp could have borrowed an additional $6.7 billion as of December 31, 2011 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, 2011, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to MEHC or PPW Holdings LLC without prior state regulatory approval to the extent that it would reduce PacifiCorp's common stock equity below 45.25% of its total capitalization, excluding short-term debt and current maturities of long-term debt. This minimum level of common equity declines to 44% for the year ending December 31, 2012 and thereafter. 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, 2011, PacifiCorp's actual common stock equity percentage, as calculated under this measure, was 54.2%, and management believes that PacifiCorp could have declared a dividend of $2.2 billion under this commitment.

These commitments also restrict PacifiCorp from making any distributions to either PPW Holdings LLC or MEHC if PacifiCorp's senior 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, 2011, PacifiCorp's senior unsecured debt was rated A- by Standard & Poor's Rating Services, BBB+ by Fitch Ratings and Baa1 by Moody's Investor Service.

## Inflation

Historically, overall inflation and changing prices in the economies where PacifiCorp operates have not had a significant impact on PacifiCorp's consolidated financial results. PacifiCorp operates under a cost-of-service based rate structure administered by various state commissions and the FERC. Under this rate structure, PacifiCorp is allowed to include prudent costs in its rates, including the impact of inflation. PacifiCorp attempts to minimize the potential impact of inflation on its operations by employing prudent risk management and hedging strategies and by considering, among other areas, its impact on purchases of energy, operating expenses, materials and equipment costs, contract negotiations, future capital spending programs and long-term debt issuances. There can be no assurance that such actions will be successful.

## 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 authoritative accounting guidance. 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 Estimates**

Certain accounting measurements require management to make estimates and judgments concerning transactions that will be settled several years in the future. Amounts recognized on the Consolidated Financial Statements based on such estimates involve numerous assumptions subject to varying and potentially significant degrees of judgment and uncertainty and will likely change in the future as additional information becomes available. The following critical accounting estimates are impacted significantly by PacifiCorp's methods, judgments and assumptions used in the preparation of the Consolidated Financial Statements and should be read in conjunction with PacifiCorp's Summary of Significant Accounting Policies included in Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

*Accounting for the Effects of Certain Types of Regulation*

PacifiCorp prepares its financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, PacifiCorp is required to defer the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future rates.

PacifiCorp continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future rates 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 continuous evaluation, PacifiCorp believes the application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in future rates. The evaluation reflects the current political and regulatory climate at both the federal and state levels and is subject to change in the future. If it becomes no longer probable that the deferred costs or income will be included in future rates, the related regulatory assets and liabilities will be written off to net income, returned to customers or re-established as accumulated other comprehensive income. Total regulatory assets were $1.884 billion and total regulatory liabilities were $893 million as of December 31, 2011. 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 liabilities.

*Derivatives*

PacifiCorp is exposed to the impact of market fluctuations in commodity prices and interest rates. PacifiCorp is principally exposed to electricity and natural gas commodity price risk as it has an obligation to serve retail customer load in its service territories. PacifiCorp's load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity and wholesale electricity that is purchased and sold. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage and transmission and transportation constraints. Interest rate risk exists on variable-rate debt and future debt issuances. PacifiCorp has established a risk management process that is designed to identify, assess, monitor, report, manage and mitigate each of the various types of risk involved in its business. PacifiCorp employs a number of different derivative contracts, which may include forwards, options, swaps and other agreements, to manage price risk for electricity, natural gas and other commodities and interest rate risk. PacifiCorp does not hedge all of its commodity price and interest rate risks, thereby exposing the unhedged portion to changes in market prices. As of December 31, 2011, PacifiCorp had no derivative contracts outstanding related to hedges of interest rate risk. Refer to Notes 6 and 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding PacifiCorp's derivative contracts.

*Measurement Principles*

Derivative contracts are recorded on 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 exception afforded by GAAP. When available, the fair value of derivative contracts is estimated using unadjusted quoted prices for identical contracts in the market in which PacifiCorp transacts. When quoted prices for identical contracts are not available, PacifiCorp uses 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 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; therefore, PacifiCorp's forward price curves for those locations and periods reflect observable market quotes. As of December 31, 2011, PacifiCorp had a net derivative liability of $265 million related to contracts valued using either quoted prices or forward price curves based upon observable market quotes. Market price quotations for other electricity and natural gas trading hubs are not as readily obtainable for the first six years. Given that limited market data exists for these contracts, as well as for those contracts that are 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 unobservable inputs. The estimated fair value of these derivative contracts 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 estimated fair value of the contracts. As of December 31, 2011, PacifiCorp had a net derivative asset of $1 million related to contracts where PacifiCorp uses internal models with 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. Option components are valued using Black-Scholes-type models, such as the European option, spread option and best-of option, with the appropriate forward price curve and other inputs.

*Classification and Recognition Methodology*

Almost all of PacifiCorp's derivative contracts are probable of inclusion in rates. Therefore, changes in the estimated fair value of derivative contracts are generally recorded as net regulatory assets. Accordingly, amounts are generally not recognized in earnings until the contracts are settled and the forecasted transaction has occurred. As of December 31, 2011, PacifiCorp had $264 million recorded as net regulatory assets related to derivative contracts on the Consolidated Balance Sheets. If it becomes no longer probable that a derivative contract will be included in rates, the net regulatory asset will be written off and recognized in earnings.

*Pension 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 multiemployer plans to which PacifiCorp contributes. PacifiCorp recognizes the funded status of its defined benefit pension and other postretirement benefit plans on 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, 2011, PacifiCorp recognized a net liability totaling $551 million for the under-funded status of its defined benefit pension and other postretirement benefit plans. As of December 31, 2011, amounts not yet recognized as a component of net periodic benefit cost that were included in regulatory assets and accumulated other comprehensive income (loss) totaled $727 million and $(14) million, respectively.

The expense and benefit obligations relating to these defined benefit 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 healthcare cost trend rates. These key 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 plan experience and current market and economic conditions. Refer to Note 11 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for disclosures about PacifiCorp's defined benefit 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, 2011.

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

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

PacifiCorp chooses a healthcare cost trend rate that reflects the near and long-term expectations of increases in medical costs and corresponds to the expected benefit payment periods. The healthcare cost trend rate gradually declines to 5% in 2016, 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 healthcare cost trend rate sensitivity disclosures.

The key 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 pension and other postretirement benefits expense and the funded status. If changes were to occur for the following key assumptions, the approximate effect on the Consolidated 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, 2011 Benefit Obligations:** | | | | |
| Discount rate | $ (69) | $ 76 | $ (33) | $ 36 |
| **Effect on 2011 Periodic Cost:** | | | | |
| Discount rate | $ (4) | $ 4 | $ (2) | $ 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 PacifiCorp's funding policy for each plan. Additionally, federal laws may require PacifiCorp to increase future contributions to its pension plans, which may create more volatility in annual contributions than historically experienced and could have a material impact on PacifiCorp's consolidated financial results.

*Income Taxes*

In determining PacifiCorp's income taxes, management is required to interpret complex income tax laws and regulations, which includes consideration of regulatory implications imposed by PacifiCorp's various regulatory jurisdictions. PacifiCorp's income tax returns are 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. PacifiCorp recognizes the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. Although the ultimate resolution of PacifiCorp's federal, state and local tax examinations is uncertain, PacifiCorp believes it has made adequate provisions for these tax positions. The aggregate amount of any additional tax liabilities that may result from these examinations, if any, is not expected to have a material adverse impact on PacifiCorp's consolidated financial results. Refer to Note 12 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding PacifiCorp's income taxes.

PacifiCorp is required to pass income tax benefits related to certain property-related basis differences and other various differences on to its customers. These amounts were recognized as a net regulatory asset totaling $422 million as of December 31, 2011 and will be included in rates when the temporary differences reverse.

*Revenue Recognition - Unbilled Revenue*

Unbilled revenue was $237 million as of December 31, 2011. Revenue is recognized as electricity is delivered or services are provided. The determination of customer billings is based on a systematic reading of meters. At the end of each month, energy provided to customers since the date of the last meter reading is 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, total volumes supplied to the system, line losses, economic impacts and composition of sales among customer classes. Estimates are reversed in the following month and actual revenue is recorded based on subsequent meter readings.

## 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, interest rates and the extension of credit to counterparties with which PacifiCorp transacts. The following discussion addresses the significant market risks associated with PacifiCorp's business activities. PacifiCorp has established guidelines for credit risk management. Refer to Notes 2 and 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding PacifiCorp's contracts accounted for as derivatives.

### 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 approved products, which are reviewed frequently to respond to changing market conditions.

Risk is an inherent part of PacifiCorp's business and activities. PacifiCorp has established a risk management process that is designed to identify, assess, monitor, report, manage and mitigate each of the various types of risk involved in PacifiCorp's business. 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 contracts that have a similar volume or price relationship to its portfolio of assets, liabilities or anticipated transactions. PacifiCorp does not engage in a material amount of proprietary trading activities.

### Commodity Price Risk

PacifiCorp is principally exposed to electricity, natural gas, coal and fuel oil commodity price risk as PacifiCorp has an obligation to serve retail customer load in its service territories. PacifiCorp's load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity and wholesale electricity that is purchased and sold. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather; market liquidity; generating facility availability; customer usage; storage; and transmission and transportation constraints. PacifiCorp does not engage in a material amount of proprietary trading activities. To mitigate a portion of its commodity price risk, PacifiCorp uses commodity derivative contracts, which may be accounted for as derivatives, including forwards, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. PacifiCorp does not hedge all of its commodity price risk, thereby exposing the unhedged portion to changes in market prices. PacifiCorp's exposure to commodity price risk is generally limited by its ability to include the costs in rates, which is subject to regulatory lag that occurs between the time the costs are incurred and when the costs are included in rates, as well as the impact of any customer sharing resulting from PacifiCorp's cost adjustment mechanisms.

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 commodity contracts, 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, 2011, 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 $15 million, as measured by the VaR computations described above, compared to $13 million as of December 31, 2010. The minimum, average and maximum daily VaR (one-day holding periods) were as follows for the years ended December 31 (in millions):

| | 2011 | 2010 | 2009 |
|---|---|---|---|
| Minimum VaR (measured) | $ 6 | $ 9 | $ 11 |
| Average VaR (calculated) | 10 | 12 | 18 |
| Maximum VaR (measured) | 15 | 23 | 23 |

PacifiCorp maintained compliance with its VaR limit procedures during the year ended December 31, 2011. Changes in markets inconsistent with historical trends or assumptions used could cause actual results to exceed estimated VaR levels.

**Fair Value of Derivatives**

The table that follows summarizes PacifiCorp's price risk on commodity contracts accounted for as derivatives, excluding collateral netting of $123 million and $127 million, as of December 31, 2011 and 2010, respectively, 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) | Estimated Fair Value after Hypothetical Change in Price | |
|---|---|---|---|
| | | 10% increase | 10% decrease |
| **As of December 31, 2011:** | | | |
| Total commodity derivative contracts | $ (264) | $ (229) | $ (299) |
| **As of December 31, 2010:** | | | |
| Total commodity derivative contracts | $ (487) | $ (465) | $ (509) |

PacifiCorp's commodity derivative contracts are generally recoverable from customers in rates; therefore, net unrealized gains and losses associated with interim price movements on commodity derivative contracts do not expose PacifiCorp to earnings volatility. As of December 31, 2011 and 2010, net regulatory assets of $264 million and $487 million, respectively, were recorded related to the net derivative liability of $264 million and $487 million, respectively. Consolidated financial results would be negatively impacted if the costs of wholesale electricity, natural gas or fuel are higher or the level of wholesale electricity sales are lower than what is included in rates, including the impacts of adjustment mechanisms.

**Interest Rate Risk**

PacifiCorp is exposed to interest rate risk on its outstanding variable-rate short- and long-term debt and future debt issuances. PacifiCorp manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. As a result of the fixed interest rates, PacifiCorp's fixed-rate long-term debt does not expose PacifiCorp to the risk of earnings loss due to changes in market interest rates. Additionally, because fixed-rate long-term debt is not carried at fair value on the Consolidated Balance Sheets, changes 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. PacifiCorp may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate PacifiCorp's exposure to interest rate risk. The nature and amount of PacifiCorp's short- and long-term debt can be expected to vary from period to period as a result of future business requirements, market conditions and other factors. Refer to Notes 6, 8 and 9 of Notes to Consolidated Financial Statements in Item 1 of this Form 10-K for additional discussion of PacifiCorp's short- and long-term debt.

As of December 31, 2011 and 2010, PacifiCorp had short- and long-term variable-rate obligations totaling $1,343 million and $691 million, respectively, that expose PacifiCorp to the risk of increased interest expense in the event of increases in short-term interest rates. The market risk related to PacifiCorp's variable-rate debt as of December 31, 2011 is not hedged. If 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. The carrying value of the variable-rate obligations approximates fair value as of December 31, 2011 and 2010.

**Credit Risk**

PacifiCorp extends unsecured credit to other utilities, energy marketing companies, financial institutions and other market participants in conjunction with wholesale energy supply and purchases activities. Credit risk relates to the risk of loss that might occur as a result of nonperformance by counterparties on 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 the 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 obtains third-party guarantees, letters of credit and cash deposits. Counterparties may be assessed interest fees for delayed payments. If required, PacifiCorp exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

As of December 31, 2011, PacifiCorp's aggregate credit exposure from wholesale activities totaled $338 million, based on settlement and mark-to-market exposures, net of collateral. As of December 31, 2011, $333 million, or 99%, of PacifiCorp's credit exposure was with counterparties having investment grade credit ratings by either Moody's Investor Service or Standard & Poor's Rating Services. As of December 31, 2011, $5 million, or 1%, of such credit exposure was with counterparties having externally rated "non-investment grade" credit ratings. As of December 31, 2011, four counterparties comprised $274 million, or 81%, of the aggregate credit exposure. All four counterparties are rated investment grade by Moody's Investor Service and Standard & Poor's Rating Services and PacifiCorp is not aware of any factors that would likely result in a downgrade of the counterparties' credit ratings to below investment grade over the remaining term of transactions outstanding as of December 31, 2011.

## Item 8. Financial Statements and Supplementary Data

**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 subsidiaries (the "Company") as of December 31, 2011 and 2010, and the related consolidated statements of operations, cash flows, changes in equity and comprehensive income for each of the three years in the period ended December 31, 2011. 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 subsidiaries as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 27, 2012

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

| | As of December 31, 2011 | 2010 |
|---|---|---|
| **ASSETS** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 47 | $ 31 |
| Accounts receivable, net | 653 | 628 |
| Income taxes receivable | 70 | 345 |
| Inventories: | | |
| Materials and supplies | 196 | 186 |
| Fuel | 237 | 188 |
| Derivative contracts | 11 | 114 |
| Deferred income taxes | 129 | 83 |
| Other current assets | 140 | 120 |
| Total current assets | 1,483 | 1,695 |
| Property, plant and equipment, net | 17,374 | 16,392 |
| Regulatory assets | 1,810 | 1,654 |
| Derivative contracts | 4 | 9 |
| Other assets | 435 | 396 |
| **Total assets** | $ 21,106 | $ 20,146 |

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, 2011 | As of December 31, 2010 |
|---|---|---|
| **LIABILITIES AND EQUITY** | | |
| Current liabilities: | | |
| Accounts payable | $ 582 | $ 479 |
| Accrued employee expenses | 72 | 81 |
| Accrued interest | 105 | 110 |
| Accrued property and other taxes | 66 | 63 |
| Derivative contracts | 90 | 84 |
| Short-term debt | 688 | 36 |
| Current portion of long-term debt and capital lease obligations | 19 | 588 |
| Other current liabilities | 192 | 121 |
| Total current liabilities | 1,814 | 1,562 |
| Regulatory liabilities | 826 | 825 |
| Derivative contracts | 66 | 399 |
| Long-term debt and capital lease obligations | 6,194 | 5,813 |
| Deferred income taxes | 3,863 | 3,448 |
| Other long-term liabilities | 1,031 | 788 |
| Total liabilities | 13,794 | 12,835 |
| Commitments and contingencies (Note 13) | | |
| Equity: | | |
| PacifiCorp 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 | 4,479 | 4,479 |
| Retained earnings | 2,801 | 2,798 |
| Accumulated other comprehensive loss, net | (9) | (7) |
| Total common equity | 7,271 | 7,270 |
| Total PacifiCorp shareholders' equity | 7,312 | 7,311 |
| Noncontrolling interest | — | — |
| Total equity | 7,312 | 7,311 |
| **Total liabilities and equity** | $ 21,106 | $ 20,146 |

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, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| **Operating revenue** | $ 4,586 | $ 4,432 | $ 4,457 |
| **Operating costs and expenses:** | | | |
| Energy costs | 1,636 | 1,618 | 1,677 |
| Operations and maintenance | 1,103 | 1,081 | 1,035 |
| Depreciation and amortization | 611 | 561 | 549 |
| Taxes, other than income taxes | 152 | 136 | 136 |
| Total operating costs and expenses | 3,502 | 3,396 | 3,397 |
| **Operating income** | 1,084 | 1,036 | 1,060 |
| **Other income (expense):** | | | |
| Interest expense | (392) | (387) | (394) |
| Allowance for borrowed funds | 25 | 45 | 35 |
| Allowance for equity funds | 47 | 79 | 64 |
| Interest income | 5 | 5 | 19 |
| Other, net | (1) | (1) | — |
| Total other income (expense) | (316) | (259) | (276) |
| **Income before income tax expense** | 768 | 777 | 784 |
| Income tax expense | 213 | 211 | 234 |
| **Net income** | 555 | 566 | 550 |
| Net income attributable to noncontrolling interest | — | — | 8 |
| **Net income attributable to PacifiCorp** | $ 555 | $ 566 | $ 542 |

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, | | |
|---|---|---|---|
| | 2011 | 2010 | 2009 |
| **Cash flows from operating activities:** | | | |
| Net income | $ 555 | $ 566 | $ 550 |
| Adjustments to reconcile net income to net cash flows from operating activities: | | | |
| Depreciation and amortization | 611 | 561 | 549 |
| Deferred income taxes and amortization of investment tax credits | 374 | 710 | 645 |
| Changes in regulatory assets and liabilities | (23) | 4 | 5 |
| Other, net | (25) | (58) | (32) |
| Changes in other operating assets and liabilities: | | | |
| Accounts receivable and other assets | (42) | (14) | (5) |
| Derivative collateral, net | 4 | (102) | 57 |
| Inventories | (59) | (26) | (39) |
| Income taxes receivable, net | 275 | (96) | (206) |
| Accounts payable and other liabilities | (34) | (135) | (24) |
| Net cash flows from operating activities | 1,636 | 1,410 | 1,500 |
| **Cash flows from investing activities:** | | | |
| Capital expenditures | (1,506) | (1,607) | (2,328) |
| Purchases of available-for-sale securities | — | — | (21) |
| Proceeds from sales of available-for-sale securities | — | — | 36 |
| Other, net | (23) | (6) | 5 |
| Net cash flows from investing activities | (1,529) | (1,613) | (2,308) |
| **Cash flows from financing activities:** | | | |
| Net proceeds from (repayments of) short-term debt | 652 | 36 | (85) |
| Proceeds from long-term debt | 399 | — | 992 |
| Proceeds from equity contributions | — | 100 | 125 |
| Repayments and redemptions of long-term debt and capital lease obligations | (588) | (16) | (144) |
| Preferred stock dividends | (2) | (2) | (2) |
| Common stock dividends | (550) | — | — |
| Other, net | (2) | (1) | (20) |
| Net cash flows from financing activities | (91) | 117 | 866 |
| **Net change in cash and cash equivalents** | 16 | (86) | 58 |
| **Cash and cash equivalents at beginning of period** | 31 | 117 | 59 |
| **Cash and cash equivalents at end of period** | $ 47 | $ 31 | $ 117 |

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

# PACIFICORP AND SUBSIDIARIES
# CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(Amounts in millions)

| | PacifiCorp Shareholders' Equity | | | | | | |
|---|---|---|---|---|---|---|---|
| | Preferred Stock | Common Stock | Additional Paid-in Capital | Retained Earnings | Accumulated Other Comprehensive Loss, Net | Noncontrolling Interest | Total Equity |
| **Balance, December 31, 2008** | $ 41 | $ — | $ 4,254 | $ 1,694 | $ (2) | $ 80 | $ 6,067 |
| Net income | — | — | — | 542 | — | 8 | 550 |
| Other comprehensive loss | — | — | — | — | (4) | — | (4) |
| Contributions - PacifiCorp's shareholders' equity | — | — | 125 | — | — | — | 125 |
| Contributions - noncontrolling interest | — | — | — | — | — | 28 | 28 |
| Distributions - noncontrolling interest | — | — | — | — | — | (38) | (38) |
| Preferred stock dividends declared | — | — | — | (2) | — | — | (2) |
| Other equity transactions | — | — | — | — | — | 6 | 6 |
| **Balance, December 31, 2009** | 41 | — | 4,379 | 2,234 | (6) | 84 | 6,732 |
| Deconsolidation of Bridger Coal | — | — | — | — | — | (84) | (84) |
| Net income | — | — | — | 566 | — | — | 566 |
| Other comprehensive loss | — | — | — | — | (1) | — | (1) |
| Contributions - PacifiCorp's shareholders' equity | — | — | 100 | — | — | — | 100 |
| Preferred stock dividends declared | — | — | — | (2) | — | — | (2) |
| **Balance, December 31, 2010** | 41 | — | 4,479 | 2,798 | (7) | — | 7,311 |
| Net income | — | — | — | 555 | — | — | 555 |
| Other comprehensive loss | — | — | — | — | (2) | — | (2) |
| Preferred stock dividends declared | — | — | — | (2) | — | — | (2) |
| Common stock dividends declared | — | — | — | (550) | — | — | (550) |
| **Balance, December 31, 2011** | $ 41 | $ — | $ 4,479 | $ 2,801 | $ (9) | $ — | $ 7,312 |

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

**PACIFICORP AND SUBSIDIARIES**
**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**
(Amounts in millions)

| | Years Ended December 31, | | |
|---|---|---|---|
| | **2011** | **2010** | **2009** |
| Net income | $ 555 | $ 566 | $ 550 |
| Other comprehensive income (loss), net of tax: | | | |
| Unrecognized amounts on retirement benefits, net of tax of $(1), $(1) and $(1) | (2) | (1) | (4) |
| Comprehensive income | 553 | 565 | 546 |
| Comprehensive income attributable to noncontrolling interest | — | — | 8 |
| Comprehensive income attributable to PacifiCorp | $ 553 | $ 565 | $ 538 |

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, financial institutions and incorporated municipalities. PacifiCorp is subject to comprehensive state and federal regulation. PacifiCorp's subsidiaries support its electric utility operations by providing coal mining and environmental remediation services. PacifiCorp is an indirect subsidiary of MidAmerican Energy Holdings Company ("MEHC"), a holding company based in Des Moines, Iowa that owns subsidiaries principally engaged in energy businesses. MEHC is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

## (2) Summary of Significant Accounting Policies

*Basis of Consolidation and Presentation*

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. Intercompany accounts and transactions have been eliminated.

As of December 31, 2011, PacifiCorp changed its presentation of regulatory assets and liabilities, which previously had been classified entirely as noncurrent, to present such regulatory assets and liabilities as either current or noncurrent based on the timing of the collection or refund of the respective regulatory asset or liability. To conform to the presentation as of December 31, 2011, PacifiCorp reclassified on the Consolidated Balance Sheet as of December 31, 2010, $61 million from noncurrent regulatory assets to other current assets and $24 million from noncurrent regulatory liabilities to other current liabilities.

*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 revenue and expenses during the period. These estimates include, but are not limited to, the effects of regulation; certain assumptions made in accounting for pension and other postretirement benefits; asset retirement obligations ("AROs"); income taxes; unbilled revenue; valuation of certain financial assets and liabilities, including derivative contracts; and accounting for contingencies. Actual results may differ from the estimates used in preparing the Consolidated Financial Statements.

*Accounting for the Effects of Certain Types of Regulation*

PacifiCorp prepares its financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, PacifiCorp is required to defer the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future rates.

PacifiCorp continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future rates 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 continuous evaluation, PacifiCorp believes the application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in future rates. The evaluation reflects the current political and regulatory climate at both the federal and state levels and is subject to change in the future. If it becomes no longer probable that the deferred costs or income will be included in future rates, the related regulatory assets and liabilities will be written off to net income, returned to customers or re-established as accumulated other comprehensive income (loss) ("AOCI").

*Fair Value Measurements*

As defined under GAAP, fair value is the price that would be received to sell an asset or paid to transfer a liability between market participants in the principal market or in the most advantageous market when no principal market exists. Adjustments to transaction prices or quoted market prices may be required in illiquid or disorderly markets in order to estimate fair value. Different valuation techniques may be appropriate under the circumstances to determine the value that would be received to sell an asset or paid to transfer a liability in an orderly transaction. Market participants are assumed to be independent, knowledgeable, able and willing to transact an exchange and not under duress. Nonperformance or credit risk is considered in determining fair value. Considerable judgment may be required in interpreting market data used to develop the estimates of fair value. Accordingly, estimates of fair value presented herein are not necessarily indicative of the amounts that could be realized in a current or future market exchange.

*Cash Equivalents and Restricted Cash and Investments*

Cash equivalents consist of funds invested in United States Treasury Bills, money market funds and 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 other assets on the Consolidated Balance Sheets.

*Investments*

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 AOCI, net of tax. As of December 31, 2011 and 2010, PacifiCorp had no unrealized gains and losses on available-for-sale securities.

PacifiCorp utilizes the equity method of accounting with respect to investments when it possesses the ability to exercise significant influence, but not control, over the operating and financial policies of the investee. The ability to exercise significant influence is presumed when an investor possesses more than 20% of the voting interests of the investee. This presumption may be overcome based on specific facts and circumstances that demonstrate that the ability to exercise significant influence is restricted. In applying the equity method, PacifiCorp records the investment at cost and subsequently increases or decreases the carrying value of the investment by PacifiCorp's proportionate share of the net earnings or losses and other comprehensive income (loss) ("OCI") of the investee. PacifiCorp records dividends or other equity distributions as reductions in the carrying value of the investment.

Effective January 1, 2010, PacifiCorp deconsolidated Bridger Coal Company ("Bridger Coal") as a result of new accounting guidance. As a result, Bridger Coal has been accounted for under the equity method since that date.

*Allowance for Doubtful Accounts*

Accounts receivable are stated at the outstanding principal amount, net of estimated allowances for doubtful accounts. The allowance for doubtful accounts is based on PacifiCorp's assessment of the collectibility of amounts owed to PacifiCorp by its customers. This assessment requires judgment regarding the ability of customers to pay 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 on the Consolidated Balance Sheets is summarized as follows for the years ended December 31 (in millions):

| | 2011 | 2010 | 2009 |
|---|---|---|---|
| Beginning balance | $ 8 | $ 7 | $ 9 |
| Charged to operating costs and expenses, net | 13 | 12 | 12 |
| Write-offs, net | (12) | (11) | (14) |
| Ending balance | $ 9 | $ 8 | $ 7 |

*Derivatives*

PacifiCorp employs a number of different derivative contracts, including forwards, options, swaps and other agreements, to manage price risk for electricity, natural gas and other commodities and interest rate risk. Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at estimated fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. Derivative balances reflect offsetting permitted under master netting arrangements with counterparties and cash collateral paid or received under such agreements.

Commodity derivatives 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. Normal purchases or normal sales contracts are not marked-to-market and settled amounts are recognized as operating revenue or energy costs on the Consolidated Statements of Operations.

For PacifiCorp's derivatives not designated as hedging contracts, the settled amount is generally included in rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives and probable of inclusion in rates are recorded as net regulatory assets. For a derivative contract not probable of inclusion in rates, changes in the fair value are recognized in earnings.

*Inventories*

Inventories consist 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*

Additions to property, plant and equipment are recorded at cost. PacifiCorp capitalizes all construction related material, direct labor and contract services, as well as indirect construction costs, which include debt and equity allowance for funds used during construction ("AFUDC"). The cost of additions and betterments are capitalized, while costs incurred that do not improve or extend the useful lives of the related assets are generally expensed.

Depreciation and amortization are generally computed on the straight-line method based on composite asset class lives prescribed by PacifiCorp's various regulatory authorities or over the assets' estimated useful lives. Depreciation studies are completed periodically to determine the appropriate composite asset class lives, net salvage and depreciation rates. These studies are reviewed and rates are ultimately approved by the various regulatory authorities. Net salvage includes the estimated future residual values of the assets and any estimated removal costs recovered through approved depreciation rates. Estimated removal costs are recorded as either a cost of removal regulatory liability or an ARO liability on the Consolidated Balance Sheets, depending on whether the obligation meets the requirements of an ARO. As actual removal costs are incurred, the associated liability is reduced.

Generally when PacifiCorp retires or sells a component of regulated property, plant and equipment, it charges the original cost and any net proceeds from the disposition to accumulated depreciation. Any gain or loss on disposals of all other assets is recorded through earnings.

PacifiCorp records debt and equity 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. AFUDC is computed based on guidelines set forth by the Federal Energy Regulatory Commission ("FERC"). After construction is completed, PacifiCorp is permitted to earn a return on these costs as a component of the related assets, as well as recover these costs through depreciation expense over the useful lives of the related assets.

*Asset Retirement Obligations*

PacifiCorp recognizes AROs when it has a legal obligation to perform decommissioning, reclamation or removal activities upon retirement of an asset. PacifiCorp's AROs are primarily associated with its generating facilities. 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 original estimate of undiscounted cash flows (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, net and amounts recovered in rates to satisfy such liabilities is recorded as a regulatory asset or liability.

*Revenue Recognition*

Revenue is recognized as electricity is delivered or services are provided. Revenue recognized includes billed, as well as unbilled, amounts. As of December 31, 2011 and 2010, unbilled revenue was $237 million and $206 million, respectively, and is included in accounts receivable, net on the Consolidated Balance Sheets. Rates charged are established by regulators or contractual arrangements.

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, energy provided to customers since the date of the last meter reading is 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, total volumes supplied to the system, line losses, economic impacts and composition of customer classes.

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

*Income Taxes*

Berkshire Hathaway includes PacifiCorp in its United States federal income tax return. Consistent with established regulatory practice, PacifiCorp's provision for income taxes has been computed on a stand-alone basis.

Deferred income tax assets and liabilities are based on differences between the financial statement and income tax basis of assets and liabilities using estimated income tax rates expected to be 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 OCI are charged or credited directly to OCI. 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 are charged or credited directly to a regulatory asset or liability. These amounts were recognized as a net regulatory asset totaling $422 million and $426 million as of December 31, 2011 and 2010, 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 are included in other long-term liabilities on the Consolidated Balance Sheets and were $38 million and $42 million as of December 31, 2011 and 2010, respectively.

In determining PacifiCorp's income taxes, management is required to interpret complex tax laws and regulations, which includes consideration of regulatory implications imposed by PacifiCorp's various regulatory jurisdictions. PacifiCorp's tax returns are 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. PacifiCorp recognizes the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. Although the ultimate resolution of PacifiCorp's federal, state and local tax examinations is uncertain, PacifiCorp believes it has made adequate provisions for these tax positions. The aggregate amount of any additional tax liabilities that may result from these examinations, if any, is not expected to have a material adverse effect on PacifiCorp's consolidated financial results. PacifiCorp's unrecognized tax benefits are primarily included in accrued property and other taxes and other long-term liabilities on the Consolidated Balance Sheets. Estimated interest and penalties, if any, related to uncertain tax positions are included as a component of income tax expense on the Consolidated Statements of Operations.

*Segment Information*

PacifiCorp currently has one segment, which includes its regulated electric utility operations.

*New Accounting Pronouncements*

In December 2011, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2011-11, which amends FASB Accounting Standards Codification ("ASC") Topic 210, "Balance Sheet." The amendments in this guidance require an entity to provide quantitative disclosures about offsetting financial instruments and derivative instruments. Additionally, this guidance requires qualitative and quantitative disclosures about master netting agreements or similar agreements when the financial instruments and derivative instruments are not offset. This guidance is effective for fiscal years beginning on or after January 1, 2013, and for interim periods within those fiscal years. PacifiCorp is currently evaluating the impact of adopting this guidance on its disclosures included within Notes to Consolidated Financial Statements.

In September 2011, the FASB issued ASU No. 2011-09, which amends FASB ASC Subtopic 715-80, "Compensation-Retirement Benefits-Multiemployer Plans." The amendments in this guidance require additional disclosures regarding an entity's participation in multiemployer pension plans and other postretirement benefit plans, as well as certain qualitative and quantitative disclosures regarding individually significant multiemployer pension plans. PacifiCorp adopted this guidance as of December 31, 2011. Refer to the additional disclosures required by ASU No. 2011-09 at Note 11.

In June 2011, the FASB issued ASU No. 2011-05, which amends FASB ASC Topic 220, "Comprehensive Income." ASU No. 2011-05 provides an entity with the option to present the total of comprehensive income, the components of net income and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. Regardless of the option chosen, this guidance also requires presentation of items on the face of the financial statements that are reclassified from other comprehensive income to net income. This guidance does not change the items that must be reported in other comprehensive income, when an item of other comprehensive income must be reclassified to net income or how tax effects of each item of other comprehensive income are presented. This guidance is effective for interim and annual reporting periods beginning after December 15, 2011. PacifiCorp is currently evaluating which presentation option will be implemented. In December 2011, the FASB issued ASU No. 2011-12, which also amends FASB ASC Topic 220 to defer indefinitely the ASU No. 2011-05 requirement to present items on the face of the financial statements that are reclassified from other comprehensive income to net income. ASU No. 2011-12 is also effective for interim and annual reporting periods beginning after December 15, 2011.

In May 2011, the FASB issued ASU No. 2011-04, which amends FASB ASC Topic 820, "Fair Value Measurements and Disclosures." The amendments in this guidance are not intended to result in a change in current accounting. ASU No. 2011-04 requires additional disclosures relating to fair value measurements categorized within Level 3 of the fair value hierarchy, including quantitative information about unobservable inputs, the valuation process used by the entity and the sensitivity of unobservable input measurements. Additionally, entities are required to disclose the level of the fair value hierarchy for assets and liabilities that are not measured at fair value in the balance sheet, but for which disclosure of the fair value is required. This guidance is effective for interim and annual reporting periods beginning after December 15, 2011. PacifiCorp is currently evaluating the impact of adopting this guidance on its disclosures included within Notes to Consolidated Financial Statements.

In January 2010, the FASB issued ASU No. 2010-06, which amends FASB ASC Topic 820, "Fair Value Measurements and Disclosures." ASU No. 2010-06 requires disclosure of (a) the amount of significant transfers into and out of Levels 1 and 2 of the fair value hierarchy and the reasons for those transfers and (b) gross presentation of purchases, sales, issuances and settlements in the Level 3 fair value measurement rollforward. This guidance clarifies that existing fair value measurement disclosures should be presented for each class of assets and liabilities. The existing disclosures about the valuation techniques and inputs used to measure fair value for both recurring and nonrecurring fair value measurements have also been clarified to ensure such disclosures are presented for the Levels 2 and 3 fair value measurements. PacifiCorp adopted this guidance as of January 1, 2010, with the exception of the disclosure requirement to present purchases, sales, issuances and settlements gross in the Level 3 fair value measurement rollforward, which PacifiCorp adopted as of January 1, 2011. The adoption of this guidance did not have a material impact on PacifiCorp's disclosures included within Notes to Consolidated Financial Statements.

## (3) Property, Plant and Equipment, Net

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

| | Depreciable Life | 2011 | 2010 |
|---|---|---|---|
| **Property, plant and equipment:** | | | |
| Generation | 20 - 80 years | $ 10,429 | $ 9,901 |
| Transmission | 25 - 75 years | 4,503 | 4,335 |
| Distribution | 20 - 65 years | 5,683 | 5,491 |
| Intangible plant[1] | 5 - 65 years | 854 | 848 |
| Other | 5 - 50 years | 1,586 | 1,459 |
| Property, plant and equipment in service | | 23,055 | 22,034 |
| Accumulated depreciation and amortization | | (6,888) | (6,646) |
| Net property, plant and equipment in service | | 16,167 | 15,388 |
| Construction work-in-progress | | 1,207 | 1,004 |
| Total property, plant and equipment, net | | $ 17,374 | $ 16,392 |

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

The average depreciation and amortization rate applied to depreciable property, plant and equipment was 2.8% for the years ended December 31, 2011 and 2010 and 2.9% for the year ended December 31, 2009.

*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 $159 million as of December 31, 2011 and 2010 and accumulated depreciation of $107 million and $102 million as of December 31, 2011 and 2010, respectively.

## (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, transmission and distribution facilities. PacifiCorp accounts for its proportionate share of each facility, and each joint owner has provided financing for its share of each facility. Operating costs of each facility are assigned to joint owners based on their percentage of ownership or energy production, depending on the nature of the cost. Operating costs and expenses on 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, 2011 (dollars in millions):

| | PacifiCorp Share | Facility in Service | Accumulated Depreciation and Amortization | Construction Work-in-Progress |
|---|---|---|---|---|
| Jim Bridger Nos. 1 - 4 | 67% | $ 1,074 | $ 491 | $ 21 |
| Hunter No. 1 | 94 | 342 | 146 | 43 |
| Hunter No. 2 | 60 | 291 | 80 | 12 |
| Wyodak | 80 | 449 | 152 | 1 |
| Colstrip Nos. 3 and 4 | 10 | 222 | 116 | 2 |
| Hermiston (1) | 50 | 171 | 52 | 1 |
| Craig Nos. 1 and 2 | 19 | 176 | 88 | — |
| Hayden No. 1 | 25 | 51 | 24 | — |
| Hayden No. 2 | 13 | 32 | 15 | — |
| Foote Creek | 79 | 37 | 18 | — |
| Transmission and distribution facilities | Various | 315 | 50 | 1 |
| Total | | $ 3,160 | $ 1,232 | $ 81 |

(1) As discussed in Note 17, PacifiCorp has contracted to purchase the remaining 50% of the output of the Hermiston generating facility.

## (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 on the Consolidated Balance Sheets consist of the following as of December 31 (in millions):

| | Weighted Average Remaining Life | 2011 | 2010 |
|---|---|---|---|
| Employee benefit plans[1] | 10 years | $ 727 | $ 595 |
| Unrealized loss on derivative contracts | 1 year | 264 | 487 |
| Deferred income taxes[2] | 33 years | 444 | 448 |
| Unamortized contract values[3] | 9 years | 187 | — |
| Other | Various | 188 | 124 |
| Noncurrent regulatory assets | | 1,810 | 1,654 |
| Current regulatory assets | | 74 | 61 |
| Total regulatory assets | | $ 1,884 | $ 1,715 |

(1) Substantially represents amounts not yet recognized as a component of net periodic benefit cost that are expected to be included in rates when recognized. Amounts are partially offset by $4 million and $12 million of the unamortized portion of net regulatory deferrals related to curtailment gains and the measurement date change transitional adjustment as of December 31, 2011 and 2010, respectively.

(2) Amounts primarily represent income tax benefits related to certain property-related basis differences and other various items that PacifiCorp is required to pass on to its customers.

(3) Represents frozen values of contracts previously accounted for as derivatives and recorded at fair value, including $168 million reclassified from unrealized loss on derivative contracts to unamortized contract values as a result of designating certain commodity derivatives as normal purchases or normal sales in December 2011. Refer to Note 6 for additional information.

PacifiCorp had regulatory assets not earning a return on investment of $1.662 billion and $1.575 billion as of December 31, 2011 and 2010, respectively.

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

| | Weighted Average Remaining Life | 2011 | 2010 |
|---|---|---|---|
| Cost of removal[1] | 33 years | $ 782 | $ 782 |
| Deferred income taxes | Various | 22 | 22 |
| Other | Various | 22 | 21 |
| Noncurrent regulatory liabilities | | 826 | 825 |
| Current regulatory liabilities | | 67 | 24 |
| Total regulatory liabilities | | $ 893 | $ 849 |

(1) Amounts represent estimated costs, as accrued through depreciation rates and exclusive of ARO liabilities, of removing property, plant and equipment in accordance with accepted regulatory practices. Amounts are deducted from rate base or otherwise accrue a carrying cost.

## (6) Fair Value Measurements

The carrying value of PacifiCorp's cash, certain cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximates fair value because of the short-term maturity of these instruments. PacifiCorp has various financial assets and liabilities that are measured at fair value on the Consolidated Financial Statements 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 or 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 its own data.

The following table presents PacifiCorp's assets and liabilities recognized on the Consolidated Balance Sheets and measured at fair value on a recurring basis (in millions):

| | Input Levels for Fair Value Measurements | | | | |
|---|---|---|---|---|---|
| | **Level 1** | **Level 2** | **Level 3** | **Other**[1] | **Total** |
| **As of December 31, 2011** | | | | | |
| **Assets:** | | | | | |
| Commodity derivatives | $ — | $ 114 | $ 1 | $ (100) | $ 15 |
| Investments in available-for-sale securities - Money market mutual funds[2] | 33 | — | — | — | 33 |
| | $ 33 | $ 114 | $ 1 | $ (100) | $ 48 |
| **Liabilities - Commodity derivatives** | $ — | $ (379) | $ — | $ 223 | $ (156) |
| **As of December 31, 2010** | | | | | |
| **Assets:** | | | | | |
| Commodity derivatives | $ — | $ 263 | $ 5 | $ (145) | $ 123 |
| Investments in available-for-sale securities - Money market mutual funds[2] | 29 | — | — | — | 29 |
| | $ 29 | $ 263 | $ 5 | $ (145) | $ 152 |
| **Liabilities - Commodity derivatives** | $ — | $ (405) | $ (350) | $ 272 | $ (483) |

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $123 million and $127 million as of December 31, 2011 and 2010, respectively.

(2) Amounts are included in cash and cash equivalents, other current assets and other assets on the Consolidated Balance Sheets. The fair value of these money market mutual funds approximates cost.

Derivative contracts are recorded on 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 exception afforded by GAAP. When available, the fair value of derivative contracts is estimated using unadjusted quoted prices for identical contracts in the market in which PacifiCorp transacts. When quoted prices for identical contracts are not available, PacifiCorp uses 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 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; 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 first six years. Given that limited market data exists for these contracts, as well as for those contracts that are 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 unobservable inputs. The estimated fair value of these derivative contracts is a function of underlying forward commodity prices, interest rates, currency rates, related volatility, counterparty creditworthiness and duration of contracts. Refer to Note 7 for further discussion regarding PacifiCorp's risk management and hedging activities.

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

PacifiCorp's investments in money market mutual funds are accounted for as available-for-sale securities and are stated at fair value. PacifiCorp uses a readily observable quoted market price or net asset value of an identical security in an active market to record the fair value.

The following table reconciles the beginning and ending balances of PacifiCorp's commodity derivative assets and liabilities measured at fair value on a recurring basis using significant Level 3 inputs for the years ended December 31 (in millions):

| | 2011 | 2010 | 2009 |
|---|---|---|---|
| **Beginning balance** | $ (345) | $ (380) | $ (408) |
| Changes in fair value recognized in net regulatory assets | 132 | (38) | (5) |
| Contracts designated as normal purchases or normal sales | 168 | — | — |
| Settlements | 46 | 73 | 56 |
| Net transfers to Level 2 | — | — | (23) |
| **Ending balance** | $ 1 | $ (345) | $ (380) |

In December 2011, PacifiCorp elected to designate certain derivative contracts as normal purchases or normal sales, an exception afforded by GAAP. As a result of making the designation, the fair value of the contracts was frozen as of December 31, 2011 and $168 million of net derivative liabilities was reclassified from derivative contracts to other assets and liabilities. The frozen liability and associated regulatory asset will be amortized over the remaining terms of the agreements.

PacifiCorp's long-term debt is carried at cost on the Consolidated Financial Statements. The fair value of PacifiCorp's long-term debt has been estimated based upon quoted market prices, where available, or at the present value of future cash flows discounted at rates consistent with comparable maturities with similar credit risks. The carrying value of PacifiCorp's 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 value and estimated fair value of PacifiCorp's long-term debt as of December 31 (in millions):

| | 2011 | | 2010 | |
|---|---|---|---|---|
| | **Carrying Value** | **Fair Value** | **Carrying Value** | **Fair Value** |
| Long-term debt | $ 6,157 | $ 7,804 | $ 6,344 | $ 7,086 |

## (7) Risk Management and Hedging Activities

PacifiCorp is exposed to the impact of market fluctuations in commodity prices and interest rates. PacifiCorp is principally exposed to electricity, natural gas, coal and fuel oil commodity price risk as it has an obligation to serve retail customer load in its regulated service territories. PacifiCorp's load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity and wholesale electricity that is purchased and sold. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. Interest rate risk exists on variable-rate debt and future debt issuances. PacifiCorp does not engage in a material amount of proprietary trading activities.

PacifiCorp has established a risk management process that is designed to identify, assess, monitor, report, manage and mitigate each of the various types of risk involved in its business. To mitigate a portion of its commodity price risk, PacifiCorp uses commodity derivative contracts, which may include forwards, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. PacifiCorp manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. Additionally, PacifiCorp may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate PacifiCorp's exposure to interest rate risk. No interest rate derivatives were in place during the periods presented. PacifiCorp does not hedge all of its commodity price and interest rate risks, thereby exposing the unhedged portion to changes in market prices.

There have been no significant changes in PacifiCorp's accounting policies related to derivatives. Refer to Notes 2 and 6 for additional information on derivative contracts.

The following table, which reflects master netting arrangements and excludes contracts that have been designated as normal under the normal purchases or normal sales exception afforded by GAAP, summarizes the fair value of PacifiCorp's derivative contracts, on a gross basis, and reconciles those amounts to the amounts presented on a net basis on the Consolidated Balance Sheets (in millions):

| | Derivative Assets | | Derivative Liabilities | | |
|---|---|---|---|---|---|
| | Current | Noncurrent | Current | Noncurrent | Total |
| **As of December 31, 2011** | | | | | |
| **Not designated as hedging contracts[(1)(2)]:** | | | | | |
| Commodity assets | $ 30 | $ 7 | $ 66 | $ 12 | $ 115 |
| Commodity liabilities | (17) | (3) | (242) | (117) | (379) |
| Total | 13 | 4 | (176) | (105) | (264) |
| **Total derivatives** | 13 | 4 | (176) | (105) | (264) |
| Cash collateral (payable) receivable | (2) | — | 86 | 39 | 123 |
| **Total derivatives - net basis** | $ 11 | $ 4 | $ (90) | $ (66) | $ (141) |
| **As of December 31, 2010** | | | | | |
| **Not designated as hedging contracts[(1)(2)]:** | | | | | |
| Commodity assets | $ 185 | $ 13 | $ 34 | $ 36 | $ 268 |
| Commodity liabilities | (62) | (4) | (213) | (476) | (755) |
| Total | 123 | 9 | (179) | (440) | (487) |
| **Total derivatives** | 123 | 9 | (179) | (440) | (487) |
| Cash collateral (payable) receivable | (9) | — | 95 | 41 | 127 |
| **Total derivatives - net basis** | $ 114 | $ 9 | $ (84) | $ (399) | $ (360) |

(1) Derivative contracts within these categories subject to master netting arrangements are presented on a net basis on the Consolidated Balance Sheets.

(2) PacifiCorp's commodity derivatives are generally included in rates and as of December 31, 2011 and 2010, a net regulatory asset of $264 million and $487 million, respectively, was recorded related to the net derivative liability of $264 million and $487 million, respectively.

For PacifiCorp's commodity derivatives, the settled amount is generally included in rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives and probable of inclusion in rates are recorded as net regulatory assets. The following table reconciles the beginning and ending balances of PacifiCorp's net regulatory assets and summarizes the pre-tax gains and losses on commodity derivative contracts recognized in net regulatory assets, as well as amounts reclassified to earnings for the years ended December 31 (in millions):

| | 2011 | 2010 |
|---|---|---|
| **Beginning balance** | $ 487 | $ 367 |
| Changes in fair value recognized in net regulatory assets | (2) | 90 |
| Net losses reclassified to unamortized contract value regulatory asset | (168) | — |
| Net gains reclassified to operating revenue | 18 | 64 |
| Net losses reclassified to energy costs | (71) | (34) |
| **Ending balance** | $ 264 | $ 487 |

For PacifiCorp's derivatives for which changes in fair value are not recorded as a net regulatory asset, unrealized gains and losses are recognized on the Consolidated Statements of Operations as operating revenue for sales contracts and energy costs and operations and maintenance for purchase contracts and electricity, natural gas and fuel oil swap contracts. During the years ended December 31, 2011, 2010 and 2009, these amounts were insignificant.

*Derivative Contract Volumes*

The following table summarizes the net notional amounts of outstanding commodity derivative contracts with fixed price terms that comprise the mark-to-market values as of December 31 (in millions):

| | Unit of Measure | 2011 | 2010 |
|---|---|---|---|
| **Commodity contracts:** | | | |
| Electricity sales | Megawatt hours | (2) | (13) |
| Natural gas purchases | Decatherms | 96 | 159 |
| Fuel oil purchases | Gallons | 17 | 16 |

*Credit Risk*

PacifiCorp extends unsecured credit to other utilities, energy marketing companies, financial institutions and other market participants in conjunction with its wholesale energy supply and marketing activities. Credit risk relates to the risk of loss that might occur as a result of nonperformance by counterparties on 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 the 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 obtains third-party guarantees, letters of credit and cash deposits. Counterparties may be assessed fees for delayed payments. If required, PacifiCorp exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

*Collateral and Contingent Features*

In accordance with industry practice, certain wholesale derivative contracts contain provisions that require PacifiCorp to maintain specific credit ratings from one or more of the major credit rating agencies on its unsecured debt. These derivative contracts may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance" in the event of a material adverse change in PacifiCorp's creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2011, PacifiCorp's credit ratings from the three recognized credit rating agencies were investment grade.

The aggregate fair value of PacifiCorp's derivative contracts in liability positions with specific credit-risk-related contingent features totaled $378 million and $448 million as of December 31, 2011 and 2010, respectively, for which PacifiCorp had posted collateral of $125 million and $136 million, respectively. If all credit-risk-related contingent features for derivative contracts in liability positions had been triggered as of December 31, 2011 and 2010, PacifiCorp would have been required to post $155 million and $129 million, respectively, of additional collateral. PacifiCorp's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation or other factors.

**(8) Short-term Debt and Other Financing Agreements**

PacifiCorp has a $635 million unsecured credit facility expiring in October 2012 and an unsecured credit facility with $720 million available until July 2012, and $630 million until July 2013. The credit facilities include a fixed or variable borrowing option for which rates vary based on the borrowing option and PacifiCorp's credit ratings for its senior unsecured long-term debt securities. These facilities support PacifiCorp's commercial paper program and certain variable-rate tax-exempt bond obligations. As of December 31, 2011, PacifiCorp had $688 million of commercial paper borrowings outstanding at a weighted-average interest rate of 0.5% and no borrowings outstanding under its credit facilities. As discussed in Note 9, in January 2012, PacifiCorp issued $650 million of long-term debt, the proceeds of which were in part used to repay a significant portion of the commercial paper borrowings outstanding as of December 31, 2011. As of December 31, 2010, PacifiCorp had $36 million of commercial paper borrowings outstanding at a weighted-average interest rate of 0.3% and no borrowings outstanding under its credit facilities.

As of December 31, 2011 and 2010, PacifiCorp had $601 million of letters of credit issued under committed arrangements, of which $304 million were issued under the revolving credit agreements. These letters of credit support PacifiCorp's variable-rate tax-exempt bond obligations, were fully available as of December 31, 2011 and 2010, and expire periodically from May 2012 through November 2012.

Each revolving credit agreement and letter of credit arrangement requires that PacifiCorp's ratio of consolidated debt, including current maturities, to total capitalization at no time exceed 0.65 to 1.0. As of December 31, 2011, PacifiCorp was in compliance with the covenants of its revolving credit agreements and letter of credit arrangements.

The following table summarizes PacifiCorp's availability under its two unsecured revolving credit facilities as of December 31 (in millions):

| | | |
|---|---|---|
| **2011:** | | |
| Available revolving credit facilities | $ | 1,355 |
| Less: | | |
| Short-term debt | | (688) |
| Letters of credit supporting tax-exempt bond obligations | | (304) |
| Net revolving credit facilities available | $ | 363 |
| **2010:** | | |
| Available revolving credit facilities | $ | 1,395 |
| Less: | | |
| Short-term debt | | (36) |
| Letters of credit supporting tax-exempt bond obligations | | (304) |
| Net revolving credit facilities available | $ | 1,055 |

As of December 31, 2011, PacifiCorp had approximately $13 million of additional letters of credit issued on its behalf to provide credit support for certain transactions as required by third parties. These letters of credit were all undrawn as of December 31, 2011 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.

## (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):

| | 2011 | | | 2010 | |
|---|---|---|---|---|---|
| | Par Value | Amount | Average Interest Rate | Amount | Average Interest Rate |
| First mortgage bonds: | | | | | |
| 5.0% to 8.8%, due through 2016 | $ 457 | $ 457 | 5.6% | $ 1,043 | 6.5% |
| 3.9% to 8.5%, due 2017 to 2021 | 1,271 | 1,268 | 5.1 | 869 | 5.7 |
| 6.7% to 8.3%, due 2022 to 2026 | 404 | 404 | 7.4 | 404 | 7.4 |
| 7.7% due 2031 | 300 | 299 | 7.7 | 299 | 7.7 |
| 5.3% to 6.1% due 2034 to 2036 | 850 | 848 | 5.8 | 848 | 5.8 |
| 5.8 % to 6.4%, due 2037 to 2039 | 2,150 | 2,142 | 6.0 | 2,142 | 6.0 |
| Tax-exempt bond obligations: | | | | | |
| Variable rates, due 2013 (1)(2) | 41 | 41 | 0.1 | 41 | 0.4 |
| Variable rates, due 2014 to 2025 (2) | 325 | 325 | 0.2 | 325 | 0.3 |
| Variable rates, due 2016 to 2024 (1)(2) | 221 | 221 | 0.1 | 221 | 0.3 |
| Variable rates, due 2014 to 2025 (1)(3) | 68 | 68 | 4.0 | 68 | 4.0 |
| 5.6 to 5.7%, due 2021 to 2023 (1) | 71 | 71 | 5.6 | 71 | 5.6 |
| 6.2%, due 2030 | 13 | 13 | 6.2 | 13 | 6.2 |
| Total long-term debt | 6,171 | 6,157 | | 6,344 | |
| Capital lease obligations: | | | | | |
| 8.8% to 14.8%, due through 2036 | 56 | 56 | 11.4 | 57 | 11.4 |
| Total long-term debt and capital lease obligations | $ 6,227 | $ 6,213 | | $ 6,401 | |

Reflected as:

| | 2011 | 2010 |
|---|---|---|
| Current portion of long-term debt and capital lease obligations | $ 19 | $ 588 |
| Long-term debt and capital lease obligations | 6,194 | 5,813 |
| Total long-term debt and capital lease obligations | $ 6,213 | $ 6,401 |

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

(2) Supported by $601 million of letters of credit issued under committed bank arrangements. These letters of credit were undrawn as of December 31, 2011 and expire periodically through November 2012.

(3) Interest rates are currently fixed at 3.9% to 4.1% and are scheduled to reset in 2013.

PacifiCorp's long-term debt may include provisions that allow PacifiCorp to redeem the long-term debt in whole or in part at any time. These provisions generally include make-whole premiums.

In January 2012, PacifiCorp issued $350 million of its 2.95% First Mortgage Bonds due February 1, 2022 and $300 million of its 4.10% First Mortgage Bonds due February 1, 2042. The net proceeds were used to repay short-term debt, fund capital expenditures and for general corporate purposes. PacifiCorp currently has regulatory authority from the Oregon Public Utility Commission ("OPUC") and the Idaho Public Utilities Commission to issue an additional $950 million of long-term debt. PacifiCorp must make a notice filing with the Washington Utilities and Transportation Commission prior to any future issuance. PacifiCorp currently has an effective shelf registration statement filed with the United States Securities and Exchange Commission expected to provide for future first mortgage bond issuances through November 2013.

In May 2011, PacifiCorp issued $400 million of its 3.85% First Mortgage Bonds due June 15, 2021. The net proceeds were used to fund capital expenditures, repay short-term debt and for general corporate purposes.

In September 2010, PacifiCorp completed a re-offering of variable-rate tax-exempt bond obligations totaling $38 million. Letters of credit totaling $39 million were issued under one of PacifiCorp's unsecured revolving credit facilities to provide credit enhancement and liquidity support for these previously unenhanced obligations.

In June 2010, PacifiCorp completed a re-offering of a $45 million series of tax-exempt bond obligations. The interest rate for this obligation was previously fixed for a term which, upon scheduled expiration, was converted to a variable rate with credit enhancement and liquidity support provided by a $46 million letter of credit issued under one of PacifiCorp's unsecured revolving credit facilities.

The issuance of PacifiCorp's first mortgage bonds is limited by available property, earnings tests and other provisions of PacifiCorp's mortgage. Approximately $22 billion of PacifiCorp's eligible property (based on original cost) was subject to the lien of the mortgage as of December 31, 2011.

PacifiCorp's letters of credit agreements generally contain similar covenants and default provisions as those contained in PacifiCorp's revolving credit facilities, 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 do not occur. As of December 31, 2011, PacifiCorp was in compliance with these covenants.

PacifiCorp has entered into long-term agreements that qualify as capital leases and expire at various dates through October 2036 for transportation services, power purchase agreements, real estate and for the use of certain equipment. 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 capital lease assets of $56 million and $57 million as of December 31, 2011 and 2010, respectively, were included in property, plant and equipment, net in the Consolidated Balance Sheets.

As of December 31, 2011, the annual maturities of long-term debt and capital lease obligations, excluding unamortized discounts and including interest on capital lease obligations, for 2012 and thereafter are as follows (in millions):

| | Long-term Debt | Capital Lease Obligations | Total |
|---|---|---|---|
| 2012 | $ 17 | $ 7 | $ 24 |
| 2013 | 261 | 12 | 273 |
| 2014 | 253 | 8 | 261 |
| 2015 | 122 | 7 | 129 |
| 2016 | 57 | 7 | 64 |
| Thereafter | 5,461 | 80 | 5,541 |
| Total | 6,171 | 121 | 6,292 |
| Unamortized discount | (14) | — | (14) |
| Amounts representing interest | — | (65) | (65) |
| Total | $ 6,157 | $ 56 | $ 6,213 |

## (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 on the Consolidated Financial Statements other than those included in the cost of removal regulatory liability established via approved depreciation rates and in accordance with accepted regulatory practices. These accruals totaled $782 million as of December 31, 2011 and 2010.

As a result of the deconsolidation of Bridger Coal on January 1, 2010, PacifiCorp deconsolidated $79 million of ARO liabilities and mine reclamation trust funds. The following table reconciles the beginning and ending balances of PacifiCorp's ARO liabilities for the years ended December 31 (in millions):

| | 2011 | | 2010 | |
|---|---|---|---|---|
| **Beginning balance** | $ | 105 | $ | 181 |
| Deconsolidation of Bridger Coal | | — | | (79) |
| Change in estimated costs[1] | | 2 | | 2 |
| Additions | | 29 | | 2 |
| Retirements | | (19) | | (6) |
| Accretion | | 6 | | 5 |
| **Ending balance** | $ | 123 | $ | 105 |
| **Reflected as:** | | | | |
| Other current liabilities | $ | 20 | $ | 4 |
| Other long-term liabilities | | 103 | | 101 |
| | $ | 123 | $ | 105 |

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

Certain of PacifiCorp's decommissioning and reclamation obligations relate to jointly owned facilities and mine sites. PacifiCorp is committed to pay a proportionate share of the decommissioning or reclamation costs. In the event of a default by any of the other joint participants, PacifiCorp 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 and other postretirement benefit plans that cover the majority of its employees. In addition, PacifiCorp sponsors a defined contribution 401(k) employee savings plan ("401(k) Plan") and contributes to multiemployer pension plans for benefits offered to certain bargaining units.

### Pension and Other Postretirement Benefit Plans

PacifiCorp's pension plans include a non-contributory defined benefit pension plan, the PacifiCorp Retirement Plan ("Retirement Plan"), and the Supplemental Executive Retirement Plan ("SERP"). The Retirement Plan is closed to employees hired after January 1, 2008 for all non-union employees. The SERP was closed to new participants as of March 21, 2006. All non-union Retirement Plan participants hired prior to January 1, 2008 that did not elect to receive equivalent fixed contributions to the 401 (k) Plan effective January 1, 2009, earn benefits based on a cash balance formula. In general for union employees, benefits under the Retirement Plan were frozen at various dates from December 31, 2007 through December 31, 2011 as they are now being provided with enhanced 401(k) Plan benefits. However, certain union Retirement Plan participants continue to earn benefits under the Retirement Plan based on the employee's years of service and a final average pay formula.

PacifiCorp's other postretirement benefit plan provides healthcare and life insurance benefits to eligible retirees.

*Plan Amendments and Curtailments*

Effective January 1, 2012, PacifiCorp changed the medical benefits for the majority of Medicare-eligible participants in its other postretirement benefit plan. Medicare-eligible participants now enroll in individual medical plans, rather than company-sponsored plans, under which PacifiCorp contributes fixed amounts to the participant's health reimbursement account. As a result of this change, PacifiCorp's benefit obligation for its other postretirement benefit plan and its related regulatory assets decreased $54 million as of December 31, 2011.

Effective March 31, 2010, the Utility Workers Union of America Local Union No. 127 ("Local 127") 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 127 participants' Retirement Plan benefits were frozen on March 31, 2010. This change resulted in a $2 million curtailment gain that was recorded as a regulatory deferral and is being amortized over periods similar to those required for other recent curtailments. Also as a result of this change, PacifiCorp's pension benefit obligation and regulatory assets each decreased by $14 million as of December 31, 2010.

*Healthcare Reform Legislation*

In March 2010, the President signed into law healthcare reform legislation that included provisions to reduce the tax deductibility of other postretirement costs by the amount of retiree drug subsidies received from the federal government beginning after December 31, 2012. As a result of the legislation, PacifiCorp increased deferred income tax liabilities and regulatory assets by $39 million during the year ended December 31, 2010. PacifiCorp has received authorization from various state regulatory commissions for deferral of substantially all of the $16 million portion of the adjustment that related to income tax benefits associated with amounts previously recognized as net periodic benefit costs. The remaining $23 million of the adjustment relates to income tax benefits that will no longer be realized in the future when the net periodic benefit cost is recognized and for which recovery of the resulting higher future income tax expense will be addressed through on-going ratemaking proceedings.

The law also contains a provision that requires a 40% excise tax for group health benefits that are provided to employees above certain premium thresholds beginning in 2018. The tax would apply to the amount of premiums in excess of the thresholds. Virtually all major areas of the healthcare reform legislation, including the 40% excise tax, are subject to interpretation and implementation rules that may take several years to complete. As of December 31, 2010, PacifiCorp's other postretirement benefit obligation increased by $12 million as a result of the projected impact of the excise tax on benefits provided to a certain bargaining unit.

*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.

Net periodic benefit cost for the plans included the following components for the years ended December 31 (in millions):

| | Pension | | | Other Postretirement | | |
|---|---|---|---|---|---|---|
| | 2011 | 2010 | 2009 | 2011 | 2010 | 2009 |
| Service cost | $ 10 | $ 12 | $ 16 | $ 7 | $ 6 | $ 5 |
| Interest cost | 63 | 66 | 71 | 31 | 31 | 33 |
| Expected return on plan assets | (75) | (74) | (70) | (30) | (30) | (29) |
| Net amortization | 29 | 23 | 10 | 17 | 14 | 12 |
| Net amortization of regulatory deferrals | (9) | (10) | (8) | 1 | 1 | 1 |
| Net periodic benefit cost | $ 18 | $ 17 | $ 19 | $ 26 | $ 22 | $ 22 |

*Funded Status*

The following table is a reconciliation of the fair value of plan assets for the years ended December 31 (in millions):

| | Pension | | Other Postretirement | |
|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 |
| **Plan assets at fair value, beginning of year** | $ 960 | $ 825 | $ 389 | $ 350 |
| Employer contributions | 71 | 117 | 28 | 24 |
| Participant contributions | — | — | 9 | 9 |
| Actual return on plan assets | (13) | 102 | (4) | 44 |
| Benefits paid | (87) | (84) | (38) | (38) |
| **Plan assets at fair value, end of year** | $ 931 | $ 960 | $ 384 | $ 389 |

The following table is a reconciliation of the benefit obligations for the years ended December 31 (in millions):

| | Pension | | Other Postretirement | |
|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 |
| **Benefit obligation, beginning of year** | $ 1,236 | $ 1,199 | $ 581 | $ 545 |
| Service cost | 10 | 12 | 7 | 6 |
| Interest cost | 63 | 66 | 31 | 31 |
| Participant contributions | — | — | 9 | 9 |
| Plan amendments | (4) | — | (54) | — |
| Curtailment | — | (14) | — | — |
| Actuarial loss | 73 | 57 | 36 | 25 |
| Benefits paid, net of Medicare subsidy | (87) | (84) | (35) | (35) |
| **Benefit obligation, end of year** | $ 1,291 | $ 1,236 | $ 575 | $ 581 |
| **Accumulated benefit obligation, end of year** | $ 1,289 | $ 1,230 | | |

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

| | Pension | | Other Postretirement | |
|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 |
| Plan assets at fair value, end of year | $ 931 | $ 960 | $ 384 | $ 389 |
| Less - Benefit obligation, end of year | 1,291 | 1,236 | 575 | 581 |
| Funded status | $ (360) | $ (276) | $ (191) | $ (192) |
| Amounts recognized on the Consolidated Balance Sheets: | | | | |
| Other current liabilities | $ (4) | $ (4) | $ — | $ — |
| Other long-term liabilities | (356) | (272) | (191) | (192) |
| Amounts recognized | $ (360) | $ (276) | $ (191) | $ (192) |

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 $41 million and $40 million as of December 31, 2011 and 2010, respectively. These assets are not included in the plan assets in the above table, but are reflected in noncurrent other assets on the Consolidated Balance Sheets. The portion of the pension plans' projected benefit obligation related to the SERP was $58 million and $56 million as of December 31, 2011 and 2010, respectively.

*Unrecognized Amounts*

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

| | Pension | | Other Postretirement | |
|---|---|---|---|---|
| | 2011 | 2010 | 2011 | 2010 |
| Net loss | $ 630 | $ 507 | $ 206 | $ 142 |
| Prior service credit | (45) | (50) | (46) | — |
| Net transition obligation | — | — | — | 19 |
| Regulatory deferrals | (7) | (16) | 3 | 4 |
| Total | $ 578 | $ 441 | $ 163 | $ 165 |

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2011 and 2010 is as follows (in millions):

| | Regulatory Asset | Accumulated Other Comprehensive Loss | Total |
|---|---|---|---|
| Pension | | | |
| **Balance, December 31, 2009** | $ 430 | $ 9 | $ 439 |
| Net loss arising during the year | 27 | 2 | 29 |
| Curtailment | (14) | — | (14) |
| Net amortization | (13) | — | (13) |
| Total | — | 2 | 2 |
| **Balance, December 31, 2010** | 430 | 11 | 441 |
| Net loss arising during the year | 157 | 4 | 161 |
| Prior service credit arising during the year | (4) | — | (4) |
| Net amortization | (19) | (1) | (20) |
| Total | 134 | 3 | 137 |
| **Balance, December 31, 2011** | $ 564 | $ 14 | $ 578 |

| | Regulatory Asset | Deferred Income Taxes | Total |
|---|---|---|---|
| Other Postretirement | | | |
| **Balance, December 31, 2009** | $ 146 | $ 23 | $ 169 |
| Net loss arising during the year | 11 | — | 11 |
| Income tax benefits no longer realizable [(1)] | 23 | (23) | — |
| Net amortization | (15) | — | (15) |
| Total | 19 | (23) | (4) |
| **Balance, December 31, 2010** | 165 | — | 165 |
| Net loss arising during the year | 70 | — | 70 |
| Prior service credit arising during the year | (46) | — | (46) |
| Reduction in net transition obligation | (8) | — | (8) |
| Net amortization | (18) | — | (18) |
| Total | (2) | — | (2) |
| **Balance, December 31, 2011** | $ 163 | $ — | $ 163 |

(1) Represents adjustments to regulatory assets associated with income tax benefits that will no longer be realized when the net periodic benefit cost is recognized as a result of the healthcare reform legislation.

The net loss, prior service credit and regulatory deferrals that will be amortized in 2012 into net periodic benefit cost are estimated to be as follows (in millions):

| | Net Loss | Prior Service Credit | Regulatory Deferrals | Total |
|---|---|---|---|---|
| Pension | $ 44 | $ (8) | $ (2) | $ 34 |
| Other postretirement | 10 | (7) | 1 | 4 |
| Total | $ 54 | $ (15) | $ (1) | $ 38 |

*Plan Assumptions*

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

| | Pension | | | Other Postretirement | | |
|---|---|---|---|---|---|---|
| | 2011 | 2010 | 2009 | 2011 | 2010 | 2009 |
| Benefit obligations as of December 31: | | | | | | |
| Discount rate | 4.90% | 5.35% | 5.80% | 4.95% | 5.45% | 5.85% |
| Rate of compensation increase | 3.50 | 3.50 | 3.00 | N/A | N/A | N/A |
| Net periodic benefit cost for the years ended December 31: | | | | | | |
| Discount rate | 5.35% | 5.80% | 6.90% | 5.45% | 5.85% | 6.90% |
| Expected return on plan assets | 7.50 | 7.75 | 7.75 | 7.50 | 7.75 | 7.75 |
| Rate of compensation increase | 3.50 | 3.00 | 3.50 | N/A | N/A | N/A |

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

| | 2011 | 2010 |
|---|---|---|
| Assumed healthcare cost trend rates as of December 31: | | |
| Healthcare cost trend rate assumed for next year | 8.50% | 8.00% |
| Rate that the cost trend rate gradually declines to | 5.00% | 5.00% |
| Year that the rate reaches the rate it is assumed to remain at | 2016 | 2016 |

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

| | Increase (Decrease) | |
|---|---|---|
| | One Percentage-Point Increase | One Percentage-Point Decrease |
| Increase (decrease) in: | | |
| Total service and interest cost | $ 3 | $ (2) |
| Other postretirement benefit obligation | 45 | (36) |

*Contributions and Benefit Payments*

Employer contributions to the pension and other postretirement benefit plans are expected to be $49 million and $9 million, respectively, during 2012. Funding to PacifiCorp's Retirement Plan trust is based upon the actuarially determined costs of the plan and the requirements of the Internal Revenue Code, the Employee Retirement Income Security Act of 1974 ("ERISA") and the Pension Protection Act of 2006, as amended ("PPA"). PacifiCorp considers contributing additional amounts from time to time in order to achieve certain funding levels specified under the PPA. PacifiCorp's funding policy for its other postretirement benefit plan is to contribute an amount equal to the sum of the net periodic benefit cost and the amount of Medicare subsidies expected to be earned during the period.

The expected benefit payments to participants in PacifiCorp's pension and other postretirement benefit plans for 2012 through 2016 and for the five years thereafter are summarized below (in millions):

| | Projected Benefit Payments | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | Other Postretirement | | | | | |
| | Pension | | Gross | | Medicare Subsidy | | Net of Subsidy | |
| 2012 | $ | 99 | $ | 35 | $ | — | $ | 35 |
| 2013 | | 103 | | 36 | | (1) | | 35 |
| 2014 | | 104 | | 36 | | (1) | | 35 |
| 2015 | | 105 | | 37 | | (1) | | 36 |
| 2016 | | 108 | | 38 | | (1) | | 37 |
| 2017 - 2021 | | 492 | | 203 | | (9) | | 194 |

*Plan Assets*

*Investment Policy and Asset Allocations*

PacifiCorp's investment policy for its pension and other postretirement benefit plans is to balance risk and return through a diversified portfolio of debt securities, equity securities and other alternative investments. Maturities for debt securities are managed to targets consistent with prudent risk tolerances. The plans retain outside investment advisors to manage plan investments within the parameters outlined by the PacifiCorp Pension Committee. The investment portfolio is managed in line with the investment policy with sufficient liquidity to meet near-term benefit payments. The return on assets assumption for each plan is based on a weighted-average of the expected performance for the types of assets in which the plans invest.

The target allocations (percentage of plan assets) for PacifiCorp's pension and other postretirement benefit plan assets are as follows as of December 31, 2011:

| | Pension[1] | Other Postretirement[1] |
|---|---|---|
| | % | % |
| Debt securities[2] | 33 - 37 | 33 - 37 |
| Equity securities[2] | 53 - 57 | 61 - 65 |
| Limited partnership interests | 8 - 12 | 1 - 3 |
| Other | 0 - 1 | 0 - 1 |

(1) PacifiCorp's Retirement 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 the other postretirement benefit plans are held in two Voluntary Employees' Beneficiary Association ("VEBA") trusts, each of which has its own investment allocation strategies. Target allocations for the other postretirement benefit plan include the separate account of the Retirement Plan trust and the two VEBA trusts.

(2) For purposes of target allocation percentages and consistent with the plans' investment policy, investment funds have been allocated based on the underlying investments in debt and equity securities.

*Fair Value Measurements*

The following table presents the fair value of plan assets, by major category, for PacifiCorp's defined benefit pension plan (in millions):

| | Input Levels for Fair Value Measurements | | | |
|---|---|---|---|---|
| | Level 1[1] | Level 2[1] | Level 3[1] | Total |
| **As of December 31, 2011** | | | | |
| Cash equivalents | $ — | $ 9 | $ — | $ 9 |
| Debt securities: | | | | |
| United States government obligations | 21 | — | — | 21 |
| International government obligations | — | 73 | — | 73 |
| Corporate obligations | — | 63 | — | 63 |
| Municipal obligations | — | 7 | — | 7 |
| Agency, asset and mortgage-backed obligations | — | 45 | — | 45 |
| Equity securities: | | | | |
| United States companies | 366 | — | — | 366 |
| International companies | 7 | — | — | 7 |
| Investment funds[2] | 104 | 165 | — | 269 |
| Limited partnership interests[3] | — | — | 71 | 71 |
| Total | $ 498 | $ 362 | $ 71 | $ 931 |
| **As of December 31, 2010** | | | | |
| Cash equivalents | $ — | $ 8 | $ — | $ 8 |
| Debt securities: | | | | |
| United States government obligations | 20 | — | — | 20 |
| International government obligations | — | 81 | — | 81 |
| Corporate obligations | — | 52 | — | 52 |
| Municipal obligations | — | 4 | — | 4 |
| Agency, asset and mortgage-backed obligations | — | 49 | — | 49 |
| Equity securities: | | | | |
| United States companies | 366 | — | — | 366 |
| International equity companies | 7 | — | — | 7 |
| Investment funds[2] | 109 | 180 | — | 289 |
| Limited partnership interests[3] | — | — | 84 | 84 |
| Total | $ 502 | $ 374 | $ 84 | $ 960 |

(1) Refer to Note 6 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds are substantially comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 59% and 41%, respectively, for 2011 and 60% and 40%, respectively, for 2010. Additionally, these funds are invested in United States and international securities of approximately 49% and 51%, respectively, for 2011 and 47% and 53%, respectively, for 2010.

(3) Limited partnership interests include several funds that invest primarily in buyout, growth equity and venture capital.

The following table presents the fair value of plan assets, by major category, for PacifiCorp's defined benefit other postretirement plan (in millions):

| | Input Levels for Fair Value Measurements | | | |
|---|---|---|---|---|
| | Level 1[1] | Level 2[1] | Level 3[1] | Total |
| **December 31, 2011** | | | | |
| Cash and cash equivalents | $ 3 | $ — | $ — | $ 3 |
| Debt securities: | | | | |
| United States government obligations | 2 | — | — | 2 |
| International government obligations | — | 5 | — | 5 |
| Corporate obligations | — | 5 | — | 5 |
| Municipal obligations | — | 1 | — | 1 |
| Agency, asset and mortgage-backed obligations | — | 3 | — | 3 |
| Equity securities: | | | | |
| United States companies | 131 | — | — | 131 |
| International companies | 2 | — | — | 2 |
| Investment funds[2] | 132 | 94 | — | 226 |
| Limited partnership interests[3] | — | — | 6 | 6 |
| Total | $ 270 | $ 108 | $ 6 | $ 384 |
| **December 31, 2010** | | | | |
| Cash and cash equivalents | $ 2 | $ 1 | $ — | $ 3 |
| Debt securities: | | | | |
| United States government obligations | 2 | — | — | 2 |
| International government obligations | — | 7 | — | 7 |
| Corporate obligations | — | 4 | — | 4 |
| Agency, asset and mortgage-backed obligations | — | 4 | — | 4 |
| Equity securities: | | | | |
| United States companies | 134 | — | — | 134 |
| International companies | 3 | — | — | 3 |
| Investment funds[2] | 118 | 107 | — | 225 |
| Limited partnership interests[3] | — | — | 7 | 7 |
| Total | $ 259 | $ 123 | $ 7 | $ 389 |

(1) Refer to Note 6 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds are substantially comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 48% and 52%, respectively, for 2011, and 47% and 53%, respectively, for 2010. Additionally, these funds are invested in United States and international securities of approximately 69% and 31%, respectively, for both 2011 and 2010.

(3) Limited partnership interests include several funds that invest primarily in buyout, growth equity and venture capital.

When available, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value. In the absence of a quoted market price or net asset value of an identical security, the fair value is determined using pricing models or net asset values based on observable market inputs and quoted market prices of securities with similar characteristics. When observable market data is not available, the fair value is determined using unobservable inputs, such as estimated future cash flows, purchase multiples paid in other comparable third-party transactions or other information. Investments in limited partnership interests are valued at estimated fair value based on the Plan's proportionate share of the partnerships' fair value as recorded in the partnerships' most recently available financial statements adjusted for recent activity and forecasted returns. The fair values recorded in the partnerships' financial statements are generally determined based on closing public market prices for publicly traded securities and as determined by the general partners for other investments based on factors including estimated future cash flows, purchase multiples paid in other comparable third-party transactions, comparable public company trading multiples and other information.

The following table reconciles the beginning and ending balances of PacifiCorp's plan assets measured at fair value using significant Level 3 inputs for the years ended December 31 (in millions):

| | Private Equity Funds | |
|---|---|---|
| | Pension | Other Postretirement |
| **Balance, December 31, 2008** | $ 78 | $ 7 |
| Actual return on plan assets still held at December 31, 2009 | 5 | 1 |
| Purchases, sales, distributions and settlements | (3) | — |
| **Balance, December 31, 2009** | 80 | 8 |
| Actual return on plan assets still held at December 31, 2010 | 10 | — |
| Purchases, sales, distributions and settlements | (6) | (1) |
| **Balance, December 31, 2010** | 84 | 7 |
| Actual return on plan assets still held at December 31, 2011 | 7 | 1 |
| Purchases, sales, distributions and settlements | (20) | (2) |
| **Balance, December 31, 2011** | $ 71 | $ 6 |

### Multiemployer Plans

PacifiCorp contributes to the following two multiemployer pension plans under the terms of collective bargaining agreements: (a) the United Mine Workers of America 1974 Pension Plan ("UMWA Pension Plan") (plan number 002); and (b) the PacifiCorp/ IBEW Local Union 57 Retirement Trust Fund ("Local 57 Trust Fund") (plan number 001). The risk of participating in multiemployer pension plans generally differs from single-employer plans in that assets are pooled such that contributions by one employer may be used to provide benefits to employees of other participating employers and plan assets cannot revert back to employers. If participating employers withdraw from the plan, the unfunded obligations of the plan may be borne by the remaining participating employers, including any employers that may have recently withdrawn. If an employer ceases participation in the plan, the employer may be obligated to pay a withdrawal liability based on the participants' unfunded, vested benefits in the plan.

The following table presents PacifiCorp's participation in its individually significant multiemployer pension plans for the years ended December 31 (dollars in millions):

| Plan name | Employer Identification Number | PPA zone status or plan funded status percentage for plan years beginning July 1,[1] 2011 | 2010 | 2009 | Funding improvement plan | Surcharge Imposed under PPA | PacifiCorp's contributions[2] 2011 | 2010 | 2009 | Year contributions to plan exceeded more than 5% of total contributions[5] |
|---|---|---|---|---|---|---|---|---|---|---|
| UMWA Pension Plan | 52-1050282 | Yellow | Green[3] | Green[4] | Pending | None | $ 3 | $ 3 | $ 2 | None |
| Local 57 Trust Fund | 87-0640888 | At least 80%[6] | At least 80% | Between 65% and 80% | None | None | $ 12 | $ 9 | $ 9 | 2010, 2009, 2008 |

(1) Among other factors, multiemployer plans in the red zone are generally less than 65 percent funded, multiemployer plans in the yellow zone are at least 65 percent but less than 80 percent funded and multiemployer plans in the green zone are at least 80 percent funded.

(2) PacifiCorp's minimum contributions to the multiemployer pension plans are based on the number of mining hours worked for the UMWA Pension Plan or the amount of wages paid to employees covered by the Local 57 Trust Fund collective bargaining agreement, subject to ERISA minimum funding requirements.

(3) The UMWA Pension Plan elected to extend recognition of investment losses incurred during the plan year ended June 30, 2009 pursuant to the Preservation of Access to Care for Medicare Beneficiaries and Pension Relief Act of 2010. Had the election not been made, the PPA zone status would have been yellow for the plan year beginning July 1, 2010.

(4) The UMWA Pension Plan elected to retain the green PPA zone status from the plan year beginning July 1, 2008 for the plan year beginning July 1, 2009 pursuant to Section 204 of the Worker, Retiree and Employer Recovery Act of 2008. Had the election not been made, the PPA zone status would have been yellow for the plan year beginning July 1, 2009.

(5) For the UMWA Pension Plan, information is for plan years beginning July 1, 2009 and 2008. Information for the plan years beginning July 1, 2010 and 2011 is not available. For the Local 57 Trust Fund, information is for plan years beginning July 1, 2010, 2009 and 2008. Information for the plan years beginning July 1, 2011 is not yet available.

(6) The preliminary plan funded status for the plan year beginning July 1, 2011 was at least 80%. PacifiCorp expects the final plan funded status, which is determined after the plan year end, will be at least 80%.

The current collective bargaining agreements governing the UMWA Pension Plan and the Local 57 Trust Fund expire in January 2013.

**Defined Contribution Plan**

PacifiCorp sponsors a defined contribution plan (401(k) plan) covering 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. PacifiCorp's contributions to the 401(k) plan were $38 million, $39 million and $34 million for the years ended December 31, 2011, 2010 and 2009, respectively.

## (12) Income Taxes

Income tax expense consists of the following for the years ended December 31 (in millions):

| | 2011 | 2010 | 2009 |
|---|---|---|---|
| **Current:** | | | |
| Federal | $ (151) | $ (498) | $ (417) |
| State | (10) | (1) | 6 |
| Total | (161) | (499) | (411) |
| **Deferred:** | | | |
| Federal | 338 | 684 | 619 |
| State | 40 | 30 | 30 |
| Total | 378 | 714 | 649 |
| **Investment tax credits** | (4) | (4) | (4) |
| Total income tax expense | $ 213 | $ 211 | $ 234 |

A reconciliation of the federal statutory income tax rate to the effective income tax rate applicable to income before income tax expense is as follows for the years ended December 31:

| | 2011 | 2010 | 2009 |
|---|---|---|---|
| Federal statutory income tax rate | 35% | 35% | 35% |
| State income taxes, net of federal benefit | 3 | 3 | 3 |
| Tax credits[1] | (10) | (8) | (6) |
| Effects of ratemaking | — | (2) | — |
| Other | — | (1) | (2) |
| Effective income tax rate | 28% | 27% | 30% |

(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 income tax liability consists of the following as of December 31 (in millions):

| | 2011 | 2010 |
|---|---|---|
| **Deferred tax assets:** | | |
| Regulatory liabilities | $ 339 | $ 322 |
| Employee benefits | 212 | 190 |
| Derivative contracts | 100 | 184 |
| Unamortized contract values | 72 | — |
| Other | 217 | 196 |
| | 940 | 892 |
| **Deferred tax liabilities:** | | |
| Property, plant and equipment | (3,919) | (3,580) |
| Regulatory assets | (715) | (650) |
| Other | (40) | (27) |
| | (4,674) | (4,257) |
| Net deferred tax liability | $ (3,734) | $ (3,365) |
| **Reflected as:** | | |
| Deferred income taxes - current assets | $ 129 | $ 83 |
| Deferred income taxes - noncurrent liabilities | (3,863) | (3,448) |
| | $ (3,734) | $ (3,365) |

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.

The United States Internal Revenue Service has closed its examination of PacifiCorp's income tax returns through the 2003 tax year. In most cases, state jurisdictions have closed their examinations of PacifiCorp's income tax returns through 1993.

As of December 31, 2011 and 2010, net unrecognized tax benefits totaled $64 million and $70 million, respectively, which included $8 million and $9 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.

## (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 impact on its consolidated financial results.

*FERC Investigation*

During 2007, the Western Electricity Coordinating Council ("WECC") audited PacifiCorp's compliance with several of the reliability standards developed by the North American Electric Reliability Corporation ("NERC"). In April 2008, PacifiCorp received 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. Also in November 2008, in conjunction with the reliability standards review, the FERC assumed control of certain aspects of the WECC's 2007 audit. In December 2011, the FERC approved a settlement among PacifiCorp, the FERC and the NERC resolving the WECC audit items that were under the FERC's control, as well as the inquiry into the February 2008 outage. The results of the settlement did not have a material impact on PacifiCorp's consolidated financial results.

*Northwest Refund Case*

In October 2011, the FERC issued an order on remand by the United States Court of Appeals for the Ninth Circuit, in which it determined that additional procedures are needed to address possible unlawful activity that may have influenced prices in the Pacific Northwest wholesale spot market during the period from December 2000 through June 2001. PacifiCorp was a participant in the Pacific Northwest wholesale spot market during this period. The FERC ordered an evidentiary, trial-type hearing before an administrative law judge to permit parties to present evidence of alleged unlawful market activity. However, the FERC held the hearing in abeyance pending settlement discussions with all parties, which are ongoing. PacifiCorp does not believe that the outcome of this proceeding will have a material impact on its consolidated financial results.

**Environmental Laws and Regulations**

PacifiCorp is subject to federal, state and local laws and regulations regarding air and water quality, renewable portfolio standards, emissions performance standards, climate change, coal combustion byproduct disposal, hazardous and solid waste disposal, protected species and other environmental matters that have the potential to impact PacifiCorp's current and future operations. PacifiCorp believes it is in material compliance with all applicable laws and regulations.

*Hydroelectric Relicensing*

PacifiCorp's hydroelectric portfolio consists of 44 generating facilities with an aggregate facility net owned capacity of 1,145 megawatts ("MW"). The FERC regulates 98% of the net capacity of this portfolio through 15 individual licenses, which have terms of 30 to 50 years. PacifiCorp expects to incur ongoing operating and maintenance expense and capital expenditures associated with the terms of its renewed hydroelectric licenses and settlement agreements, including natural resource enhancements. PacifiCorp's Klamath hydroelectric system is currently operating under annual licenses. Substantially all of PacifiCorp's remaining hydroelectric generating facilities are operating under licenses that expire between 2030 and 2058.

*Klamath Hydroelectric System - Klamath River, Oregon and California*

In February 2010, PacifiCorp, the United States Department of the Interior, the United States Department of Commerce, the State of California, the State of Oregon and various other governmental and non-governmental settlement parties signed the Klamath Hydroelectric Settlement Agreement ("KHSA"). Among other things, the KHSA provides that the United States Department of the Interior conduct scientific and engineering studies to assess whether removal of the Klamath hydroelectric system's four mainstem dams is in the public interest and will advance restoration of the Klamath Basin's salmonid fisheries. If it is determined that dam removal should proceed, dam removal is expected to commence no earlier than 2020.

Under the KHSA, PacifiCorp and its customers are protected from uncapped dam removal costs and liabilities. For dam removal to occur, federal legislation consistent with the KHSA must be enacted to provide, among other things, protection for PacifiCorp from all liabilities associated with dam removal activities. If Congress does not enact legislation, then PacifiCorp will resume relicensing at the FERC. In November 2011, bills were introduced in both chambers of the United States Congress that, if passed, would enact the KHSA and a companion agreement that seeks to resolve other water-related conflicts and restore habitat in the Klamath basin. PacifiCorp expects that congressional hearings on the legislation may begin in early 2012.

In addition, the KHSA limits PacifiCorp's contribution to dam removal costs to no more than $200 million, of which up to $184 million would be collected from PacifiCorp's Oregon customers with the remainder to be collected from PacifiCorp's California customers. An additional $250 million for dam removal costs is expected to be raised through a California bond measure or other appropriate State of California financing mechanism. If dam removal costs exceed $200 million and if the State of California is unable to raise the additional funds necessary for dam removal costs, sufficient funds would need to be provided by an entity other than PacifiCorp in order for the KHSA and dam removal to proceed.

PacifiCorp has begun collection of surcharges from Oregon customers for their share of dam removal costs, as approved by the OPUC, and is depositing the proceeds in a trust account maintained by the OPUC. PacifiCorp will begin collection of surcharges from California customers for their share of dam removal costs as approved by the California Public Utilities Commission ("CPUC"), upon the establishment of two trust accounts. In January 2012, the CPUC notified PacifiCorp that the necessary trust accounts had been established to allow PacifiCorp to begin collecting the dam removal surcharge from California customers. PacifiCorp is authorized to collect the surcharge over the next nine years.

As of December 31, 2011, PacifiCorp's property, plant and equipment, net included $124 million of costs associated with the Klamath hydroelectric system's four mainstem dams and the associated relicensing and settlement costs. PacifiCorp has received approvals from the OPUC, the CPUC and the Wyoming Public Service Commission to depreciate the Klamath hydroelectric system's four mainstem dams and the associated relicensing and settlement costs through the expected dam removal date. The depreciation rate changes were effective January 1, 2011 and will allow for full depreciation of the assets by December 2019 for those jurisdictions. PacifiCorp filed for consistent ratemaking treatment in the last Idaho general rate case, which was settled in January 2012. PacifiCorp expects to seek similar approval in Washington. As part of the July 2011 Utah general rate case settlement that was approved by the Utah Public Service Commission ("UPSC") in August 2011, PacifiCorp and the other parties to the settlement agreed to defer a decision regarding the acceleration of the depreciation rates for the Klamath hydroelectric system's four mainstem dams to a future rate proceeding, at which time Utah's $34 million share of associated relicensing and settlement costs would be addressed.

*Hydroelectric Commitments*

As described above, certain of PacifiCorp's hydroelectric licenses contain requirements for PacifiCorp to make certain capital and operating expenditures related to its hydroelectric facilities. PacifiCorp estimates it is obligated to make capital expenditures of approximately $205 million over the next 10 years related to these licenses.

**Commitments**

PacifiCorp has the following firm commitments that are not reflected on the Consolidated Balance Sheet. Minimum payments as of December 31, 2011 are as follows (in millions):

| | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 and Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Purchased electricity contracts | $ 245 | $ 139 | $ 97 | $ 99 | $ 79 | $ 447 | $ 1,106 |
| Fuel contracts | 677 | 633 | 599 | 503 | 399 | 2,390 | 5,201 |
| Construction commitments | 550 | 247 | 24 | 7 | 8 | 52 | 888 |
| Transmission | 108 | 98 | 84 | 62 | 54 | 702 | 1,108 |
| Operating leases and easements | 11 | 12 | 4 | 3 | 2 | 44 | 76 |
| Maintenance, service and other contracts | 32 | 22 | 17 | 7 | 4 | 49 | 131 |
| Total commitments | $ 1,623 | $ 1,151 | $ 825 | $ 681 | $ 546 | $ 3,684 | $ 8,510 |

*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. Included in the purchased electricity payments are any power purchase agreements that meet the definition of an operating lease.

Included in the minimum fixed annual payments for purchased electricity above are commitments to purchase electricity from several hydroelectric 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 on 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 2011, 2010 and 2009 energy sources.

*Fuel*

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

*Construction Commitments*

PacifiCorp's construction commitments included in the table above relate to firm commitments and include the following major construction commitments.

- As part of the March 2006 acquisition of PacifiCorp, MEHC and PacifiCorp made a commitment to the state regulatory commissions in all six states in which PacifiCorp has retail customers to invest in certain transmission and distribution system projects that would enhance reliability, facilitate the receipt of renewable resources and enable further system optimization. As of December 31, 2011, PacifiCorp had two remaining capital projects to complete associated with this commitment: (a) the 100-mile high-voltage transmission line being built between the Mona substation in central Utah and the Oquirrh substation in the Salt Lake Valley that is expected to be placed in service in 2013 and (b) another segment of the Energy Gateway Transmission Expansion Program that is expected to be placed in service prior to 2021, depending on siting, permitting and construction schedules.

- PacifiCorp is constructing the 637-MW Lake Side 2 combined-cycle combustion turbine natural gas-fueled generating facility ("Lake Side 2"), which is expected to be placed in service in 2014.

*Transmission*

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

*Operating Leases and Easements*

PacifiCorp has non-cancelable operating leases primarily for office equipment, office space, certain operating facilities, land and equipment under operating leases that expire at various dates through the year ending December 31, 2092. These leases generally require PacifiCorp to pay for insurance, taxes and maintenance applicable to the leased property. Certain leases contain renewal options for varying periods and escalation clauses for adjusting rent to reflect changes in price indices. PacifiCorp also has non-cancelable easements for land on which its wind-powered generating facilities are located. Rent expense totaled $18 million for 2011, $15 million for 2010 and $13 million for 2009.

*Maintenance, Service and Other Contracts*

PacifiCorp has various non-cancelable maintenance, service and other contracts primarily related to turbine and equipment maintenance and various other service agreements.

*Guarantees*

PacifiCorp has entered into guarantees as part of the normal course of business and the sale of certain assets. These guarantees are not expected to have a material impact on PacifiCorp's consolidated financial results.

## (14) Preferred Stock

PacifiCorp's preferred stock was as follows as of December 31 (shares in thousands, dollars in millions, except per share amounts):

| | Redemption Price Per Share | 2011 Shares | 2011 Amount | 2010 Shares | 2010 Amount |
|---|---|---|---|---|---|
| Series: | | | | | |
| Serial Preferred, $100 stated value, | | | | | |
| 3,500 shares authorized | | | | | |
| 4.52% to 4.72% | $102.3 to $103.5 | 149 | $ 15 | 149 | $ 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 |
| | | 407 | $ 41 | 407 | $ 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 not yet due for payment on preferred stock were $1 million as of December 31, 2011 and 2010.

## (15) Common Shareholder's Equity

In January 2012, PacifiCorp declared a dividend of $50 million, which was paid to PPW Holdings LLC, a direct wholly owned subsidiary of MEHC and PacifiCorp's direct parent company, in February 2012.

In March 2011, PacifiCorp declared a dividend of $275 million, which was paid to PPW Holdings LLC in April 2011.

In January 2011, PacifiCorp declared a dividend of $275 million, which was paid to PPW Holdings LLC in February 2011.

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, 2011, 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 45.25% of its total capitalization, excluding short-term debt and current maturities of long-term debt. This minimum level of common equity declines to 44% for the year ending December 31, 2012 and thereafter. 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, 2011, PacifiCorp's actual common stock equity percentage, as calculated under this measure, was 54.2%, and PacifiCorp would have been permitted to dividend $2.2 billion under this commitment.

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, 2011, 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 a maximum debt-to-total capitalization percentage under various financing agreements as further discussed in Notes 8 and 9.

### (16) Components of Accumulated Other Comprehensive Loss, Net

Accumulated other comprehensive loss attributable to PacifiCorp, net consists of unrecognized amounts on retirement benefits of $9 million, net of tax of $5 million, and $7 million, net of tax of $4 million, as of December 31, 2011 and 2010, respectively.

### (17) Variable-Interest Entities

PacifiCorp holds an undivided interest in 50% of the 474-MW Hermiston generating facility (refer to Note 4), dictates when the generating facility operates, procures 100% of the natural gas for the generating facility 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 facility and is the primary beneficiary. PacifiCorp has been unable to obtain the information necessary to consolidate the entity because the entity has not agreed 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 $37 million during each of the years ended December 31, 2011 and 2010, and $36 million during the year ended December 31, 2009. 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.

PacifiCorp holds a two-thirds interest in Bridger Coal, which supplies coal to the Jim Bridger generating facility that is owned two-thirds by PacifiCorp and one-third by PacifiCorp's joint venture partner in Bridger Coal. PacifiCorp purchases two-thirds of the coal produced by Bridger Coal, while the remaining coal is purchased by the joint venture partner. The power to direct the activities that most significantly impact Bridger Coal's economic performance are shared with the joint venture partner. Bridger Coal's necessary working capital to carry out its mining operations is financed by contributions from PacifiCorp and its joint venture partner. PacifiCorp's equity investment in Bridger Coal was $204 million and $181 million as of December 31, 2011 and 2010, respectively. Refer to Note 18 for information regarding related-party transactions with Bridger Coal.

### (18) Related-Party Transactions

PacifiCorp has an intercompany administrative services agreement with MEHC and its subsidiaries. Amounts charged to PacifiCorp under this agreement totaled $16 million during the year ended December 31, 2011 and $9 million during each of the years ended December 31, 2010 and 2009. Payables associated with these administrative services were $7 million and $1 million as of December 31, 2011 and 2010, respectively. PacifiCorp also receives payments for services performed by PacifiCorp for MEHC and its affiliates primarily related to administrative and technology services and direct-assigned employees. These services were $2 million during each of the years ended December 31, 2011 and 2010 and $1 million during the year ended December 31, 2009. Receivables associated with these activities were $- million and $1 million as of December 31, 2011 and 2010, respectively.

PacifiCorp also engages in various transactions with several subsidiaries of MEHC in the ordinary course of business. Services provided by these affiliates in the ordinary course of business and charged to PacifiCorp relate to the transportation of natural gas and relocation services. These expenses totaled $6 million, $5 million and $3 million during the years ended December 31, 2011, 2010 and 2009, respectively.

PacifiCorp has long-term transportation contracts with BNSF Railway Company ("BNSF"), an indirect wholly owned subsidiary of Berkshire Hathaway, PacifiCorp's ultimate parent company. Transportation costs under these contracts were $33 million, $30 million and $29 million during the years ended December 31, 2011, 2010 and 2009, respectively. As of December 31, 2011 and 2010, PacifiCorp had $1 million and $2 million, respectively, of accounts payable to BNSF outstanding under these contracts, including indirect payables related to a jointly owned facility.

PacifiCorp participated in a captive insurance program provided by MEHC Insurance Services Ltd. ("MEISL"), a wholly owned subsidiary of MEHC. MEISL covered all or significant portions of the property damage and liability insurance deductibles in many of PacifiCorp's policies, as well as overhead distribution and transmission line property damage. The policy coverage period expired on March 20, 2011 and will not be renewed. Premium expenses were $2 million during the year ended December 31, 2011 and $7 million during each of the years ended December 31, 2010 and 2009. Prepayments to MEISL were $- million and $2 million as of December 31, 2011 and 2010, respectively. Receivables for claims were $6 million and $12 million as of December 31, 2011 and 2010, respectively. Proceeds from claims were $16 million, $14 million and $17 million during the years ended December 31, 2011, 2010 and 2009, 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, 2011 and 2010, income taxes receivable from MEHC were $70 million and $345 million, respectively. For the years ended December 31, 2011, 2010 and 2009, cash received for income taxes from MEHC totaled $425 million, $395 million and $252 million, respectively.

PacifiCorp transacts with its equity investees, Bridger Coal and Trapper Mining Inc. During the years ended December 31, 2011 and 2010, PacifiCorp charged Bridger Coal $2 million and $4 million, respectively, for administrative support and management services provided by PacifiCorp to Bridger Coal. Receivables for these services, as well as for certain expenses paid by PacifiCorp and reimbursed by Bridger Coal, were $3 million as of December 31, 2011 and 2010. Services provided by equity investees and charged to PacifiCorp primarily relate to coal purchases. During the years ended December 31, 2011 and 2010, coal purchases from PacifiCorp's equity investees totaled $126 million and $141 million, respectively. Payables to PacifiCorp's equity investees were $28 million and $17 million as of December 31, 2011 and 2010, respectively.

## (19) Supplemental Cash Flows Information

The summary of supplemental cash flows information for the years ended December 31 is as follows (in millions):

| | 2011 | 2010 | 2009 |
|---|---|---|---|
| Interest paid, net of amounts capitalized | $ 358 | $ 331 | $ 325 |
| Income taxes received, net | $ 425 | $ 395 | $ 252 |
| **Supplemental disclosure of non-cash investing and financing activities:** | | | |
| Accounts payable related to property, plant and equipment additions | $ 231 | $ 216 | $ 251 |

## (20) Unaudited Quarterly Operating Results (in millions)

| | Three-Month Periods Ended | | | |
|---|---|---|---|---|
| | March 31, 2011 | June 30, 2011 | September 30, 2011 | December 31, 2011 |
| Operating revenue | $ 1,119 | $ 1,091 | $ 1,198 | $ 1,178 |
| Operating income | 267 | 263 | 316 | 238 |
| Net income | 127 | 129 | 169 | 130 |
| Net income attributable to PacifiCorp | 127 | 129 | 169 | 130 |

| | Three-Month Periods Ended | | | |
|---|---|---|---|---|
| | March 31, 2010 | June 30, 2010 | September 30, 2010 | December 31, 2010 |
| Operating revenue | $ 1,106 | $ 1,052 | $ 1,165 | $ 1,109 |
| Operating income | 251 | 269 | 280 | 236 |
| Net income | 136 | 150 | 156 | 124 |
| Net income attributable to PacifiCorp | 136 | 150 | 156 | 124 |

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

None.

**Item 9A. 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, 2011 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, 2011 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, 2011.

PacifiCorp
February 27, 2012

**Item 9B. Other Information**

None.

## PART III

### Item 10. Directors, Executive Officers and Corporate Governance

PacifiCorp is an indirect subsidiary of MEHC, and its directors consist of executive management from both MEHC and PacifiCorp. Each director was elected based on individual responsibilities, experience in the energy industry and functional expertise. 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, 2012, with respect to the current directors and executive officers of PacifiCorp:

**Gregory E. Abel**, 49, Chairman of the Board of Directors and Chief Executive Officer of PacifiCorp since 2006. Mr. Abel has been Chief Executive Officer of MEHC since 2008, director since 2000, President since 1998, and was Chief Operating Officer from 1998 to 2008. Mr. Abel joined MEHC in 1992 and has extensive executive management experience in the energy industry.

**Douglas L. Anderson**, 53, Director. Mr. Anderson has been a director of PacifiCorp since 2006 and Senior Vice President, General Counsel and Corporate Secretary of MEHC since 2001. Mr. Anderson joined MEHC in 1993 and has significant legal experience, including expertise in corporate governance, mergers and acquisitions, and ethics and compliance programs.

**Micheal G. Dunn**, 46, President and Chief Executive Officer of PacifiCorp Energy and director of PacifiCorp since February 2010; President of Kern River Gas Transmission Company ("Kern River"), an indirect subsidiary of MEHC, from 2007 to January 2010; and Vice President of Operations, Information Technology and Engineering of Kern River from 2005 to 2007. Mr. Dunn joined Kern River in 1990 and has significant operational, engineering and leadership expertise in the energy industry, including managing large construction projects and asset management.

**Brent E. Gale**, 60, Director. Mr. Gale has been a director of PacifiCorp and Senior Vice President, Regulation and Legislation of MEHC since 2006 and was Senior Vice President, Legislation and Regulation of MidAmerican Energy Company, an indirect subsidiary of MEHC, from 2004 to 2006. Mr. Gale has been employed by MEHC and its predecessor companies since 1976 and has extensive regulatory experience in the utility industry at both the federal and state levels.

**Patrick J. Goodman**, 45, Director. Mr. Goodman has been a director of PacifiCorp since 2006 and Senior Vice President and Chief Financial Officer of MEHC since 1999. Mr. Goodman joined MEHC in 1995 and has significant financial experience, including expertise in mergers and acquisitions, accounting, treasury, and tax functions.

**Natalie L. Hocken**, 42, Vice President and General Counsel of Pacific Power and director of PacifiCorp since 2007 and Assistant General Counsel of PacifiCorp from 2005 to 2007. Ms. Hocken joined PacifiCorp in 2002 and has significant legal experience in the utility industry, including expertise in litigation and federal and state regulatory compliance.

**Mark C. Moench**, 56, Senior Vice President, General Counsel and Corporate Secretary of PacifiCorp since 2007; director of PacifiCorp and Senior Vice President and General Counsel of Rocky Mountain Power since 2006; Senior Vice President, Legal of MEHC from 2005 to 2006; and Vice President and General Counsel of Kern River from 2002 to 2005. Mr. Moench has significant experience regarding federal and state regulation, mergers and acquisitions, and transmission permitting.

**R. Patrick Reiten**, 50, President and Chief Executive Officer of Pacific Power and director of PacifiCorp since 2006. Mr. Reiten served as President and Chief Executive Officer of PNGC Power from 2002 to 2006 after joining PNGC Power in 1993. Mr. Reiten has significant operational, public policy and leadership experience in the energy industry, including expertise in transmission and distribution systems, community relations, and regulatory matters.

**Douglas K. Stuver**, 48, Senior Vice President and Chief Financial Officer of PacifiCorp since 2008, Controller of PacifiCorp Energy from 2006 to 2008 and Controller of PacifiCorp's commercial and trading business unit from 2004 to 2006. Mr. Stuver joined PacifiCorp in 2004 and has significant financial and energy risk management experience.

**A. Richard Walje**, 60, President and Chief Executive Officer of Rocky Mountain Power since 2006, director of PacifiCorp since 2001, Executive Vice President from 2004 to 2006 and Chief Information Officer from 2000 to 2006. Mr. Walje joined PacifiCorp in 1986 and has significant operational, engineering, and leadership experience in the utility industry, including expertise in transmission and distribution systems, customer services, and information technology.

### Board's Role in the Risk Oversight Process

PacifiCorp's Board of Directors is comprised of a combination of MEHC senior executives and PacifiCorp senior management who have direct and indirect responsibility for the management and oversight of risk. PacifiCorp's Board of Directors has not established a separate risk management and oversight committee.

### Audit Committee and Audit Committee Financial Expert

During the year ended December 31, 2011, and as of the date of this Annual Report on Form 10-K, PacifiCorp's Board of Directors did not have an audit committee and consisted of MEHC and PacifiCorp employees. PacifiCorp is not required to have an audit committee as its common stock is indirectly and wholly owned by MEHC. 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 Discussion and Analysis

*Compensation Philosophy and Overall Objectives*

Mr. Gregory E. Abel, our Chairman of the Board of Directors and Chief Executive Officer, or Chairman and CEO, receives no direct compensation from us. We reimburse our indirect parent company, MidAmerican Energy Holdings Company, or MEHC, for the cost of Mr. Abel's time spent on matters supporting us, 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, 2011 (File No. 001-14881) for executive compensation and post-termination payment information for Mr. Abel.

We believe that the compensation paid to each of 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, among which are customer service, operational excellence, financial strength, employee commitment and safety, environmental respect and regulatory integrity.

*How is Compensation Determined*

Our compensation committee consists solely of Mr. Abel. Mr. Abel also serves as MEHC's Chairman, President and Chief Executive Officer. Mr. Abel is responsible for the establishment and oversight of our compensation policy and for approving compensation decisions for our NEOs such as 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. We do not specifically use other 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. All merit increases are approved by Mr. Abel and take effect in the last payroll period of each year. An increase or decrease in base salary may also result from a promotion or other significant change in a NEO's responsibilities during the year. In 2011, base salaries for all NEOs, other than Mr. Abel, increased on average by 5.52% and became effective December 26, 2010.

*Short-Term Incentive Compensation*

The objective of short-term incentive compensation is to reward the achievement of our 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 at Mr. Abel's sole discretion and is not based on a specific formula or cap. Mr. Abel considers a variety of factors in determining each NEO's performance award including the NEO's performance, our overall performance and each NEO's contribution to that overall performance. Mr. Abel evaluates performance using financial and non-financial principles, including customer service; operational excellence; financial strength; 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. No factor was individually material to Mr. Abel's determination regarding the amounts paid to each NEO under the AIP for 2011. Approved awards are paid prior to year-end.

*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, other than Mr. Abel, to reward the accomplishment of significant non-recurring tasks or projects. These awards are discretionary and are approved by Mr. Abel. There were no performance awards granted to our NEOs during 2011.

*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. We do not utilize stock options or other forms of equity-based awards.

*Long-Term Incentive Partnership Plan*

The MidAmerican Energy Holdings Company 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. All of our NEOs, other than Mr. Abel, participate in the LTIP. The LTIP provides for annual discretionary 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 MEHC's Chairman, President and Chief Executive Officer who recommends awards to the MEHC compensation committee annually in the fourth quarter. Except for limited situations of extraordinary performance, awards are capped at 1.5 times base salary and 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. Gains or losses may be incurred based on investment performance. Participating NEOs may elect to defer all or a part of the award or receive payment in cash after the five-year mandatory deferral and vesting period. Vested balances (including any investment gains or losses thereon) of terminating participants are paid at the time of termination.

*Other Employee Benefits*

*Supplemental Executive Retirement Plan*

Our Supplemental Executive Retirement Plan, or SERP, provides additional retirement benefits to participants. Mr. Walje was the only NEO who participated in our SERP during 2011, and we have no plans to add new participants in the future. 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 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 and 100% of short-term incentive compensation awards. We include the DCP as part of the participating NEO's overall compensation in order to provide a comprehensive, competitive package. 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. The plan allows participants to choose from three forms of distribution. The plan permits us to make discretionary contributions on behalf of participants.

*Potential Payments Upon Termination*

Our NEOs, other than Mr. Abel, are not entitled to severance or enhanced benefits upon termination of employment or change in control. However, upon any termination of employment, our other NEOs would be entitled to the vested balances in the Retirement Plan, SERP, LTIP and the DCP.

**Compensation Committee Report**

Mr. Abel, our Chairman and CEO and sole member of our compensation committee, has reviewed the Compensation Discussion and Analysis and, based on this review, has recommended to the Board of Directors that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K.

Gregory E. Abel

**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 [1] | Change in Pension Value and Nonqualified Deferred Compensation Earnings [2] | All Other Compensation [3] | Total [4] |
|---|---|---|---|---|---|---|
| Gregory E. Abel [5] | 2011 | $ — | $ — | $ — | $ — | $ — |
| Chairman and | 2010 | — | — | — | — | — |
| Chief Executive Officer | 2009 | — | — | — | — | — |
| A. Richard Walje | 2011 | 368,000 | 516,548 | 670,980 | 32,676 | 1,588,204 |
| President and Chief Executive | 2010 | 357,150 | 721,364 | 548,195 | 35,096 | 1,661,805 |
| Officer, Rocky Mountain Power | 2009 | 351,900 | 583,217 | 733,231 | 54,617 | 1,722,965 |
| R. Patrick Reiten | 2011 | 291,528 | 747,678 | 650 | 23,643 | 1,063,499 |
| President and Chief Executive | 2010 | 265,740 | 828,466 | 445 | 24,301 | 1,118,952 |
| Officer, Pacific Power | 2009 | 265,740 | 623,417 | 355 | 24,105 | 913,617 |
| Micheal G. Dunn | 2011 | 278,820 | 463,169 | 13,856 | 26,500 | 782,345 |
| President and Chief Executive | 2010 | 230,114 | 355,000 | 12,925 | 24,638 | 622,677 |
| Officer, PacifiCorp Energy | 2009 | — | — | — | — | — |
| Douglas K. Stuver | 2011 | 239,269 | 269,216 | 11,010 | 31,971 | 551,466 |
| Senior Vice President and | 2010 | 233,525 | 268,455 | 8,014 | 34,460 | 544,454 |
| Chief Financial Officer | 2009 | 228,800 | 231,033 | 12,623 | 39,945 | 512,401 |

(1) Consists of annual cash incentive awards earned pursuant to the AIP for our NEOs and the vesting of LTIP awards and associated vested earnings/(losses). The breakout for 2011 is as follows:

| | | LTIP (a) | | |
|---|---|---|---|---|
| | AIP | Vested Awards | Vested Earnings/(Losses) | Total |
| A. Richard Walje | $ 200,000 | $ 372,259 | $ (55,711) | $ 316,548 |
| R. Patrick Reiten | 275,000 | 437,400 | 35,278 | 472,678 |
| Micheal G. Dunn | 275,000 | 195,000 | (6,831) | 188,169 |
| Douglas K. Stuver | 95,000 | 154,185 | 20,031 | 174,216 |

(a) The LTIP vested awards and vested earnings/(losses) columns exclude any amounts related to Mr. Dunn's awards granted prior to him transferring to PacifiCorp.

The ultimate payouts of LTIP awards are undeterminable as the amounts to be paid out 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 participants. Net income for determining the award and the award itself are subject to discretionary adjustment by MEHC's Chairman, President and Chief Executive Officer and its compensation committee. In 2011, the gross award and per-point value were determined based on the overall achievement of our financial and non-financial objectives.

| MEHC Net Income | Award |
|---|---|
| Less than or equal to net income target goal | None |
| Exceeds net income target goal by 0.01% - 6.50% | 25% of excess |
| Exceeds net income target goal by more than 6.50% | 25% of the first 6.50% excess; and |
| | 35% of excess over 6.50% |

Points are allocated among plan participants either as initial points or year-end performance points. A nominating committee recommends the point allocation, subject to approval by MEHC's Chairman, President and Chief Executive Officer, based upon a discretionary evaluation of individual achievement of financial and non-financial goals previously described herein. A participant's award equals the participant's allocated points multiplied by the final per-point value, capped at 1.5 times base salary except in extraordinary circumstances.

(2) Amounts are based upon the aggregate increase in the actuarial present value of all qualified and nonqualified defined benefit plans, which include the SERP and our non-contributory defined benefit pension plan, or the Retirement Plan, as applicable. Amounts are computed using assumptions consistent with those used in preparing the related pension disclosures in our Notes to Consolidated Financial Statements in Item 8 of this Form 10-K and are as of December 31, 2011. No participant in our DCP earned "above market" or "preferential" earnings on amounts deferred.

(3) Amounts consist of Employee Savings Plan, or 401(k) Plan, contributions we paid on behalf of the NEOs and registrant contributions to the DCP, as noted in the Nonqualified Deferred Compensation table. Items required to be reported and quantified are as follows: Mr. Walje - 401(k) contributions of $32,014; Mr. Reiten - 401(k) contributions of $23,643; Mr. Dunn - 401(k) contributions of $11,393 and DCP contributions of $15,107; and Mr. Stuver - 401(k) contributions of $31,971.

(4) Any amounts voluntarily deferred by the NEO, if applicable, are included in the appropriate column in the Summary Compensation Table.

(5) Mr. Abel receives no direct compensation from us. We reimburse MEHC for the cost of Mr. Abel's time spent on matters supporting us, 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, 2011 (File No. 001-14881) for executive compensation information for Mr. Abel.

### Pension Benefits

The following table sets forth certain information regarding the defined benefit pension plan accounts held by each of our NEOs as of December 31, 2011:

| Name | Plan name | Number of years of credited service | Present value of accumulated benefits [1] |
|---|---|---|---|
| Gregory E. Abel | Retirement | n/a | $ — |
| A. Richard Walje | SERP | 26 years | 3,228,738 |
| | Retirement | 23 years | 982,109 |
| R. Patrick Reiten | Retirement | 2 years | 16,482 |
| Micheal G. Dunn [2] | Retirement | 2 years | 26,781 |
| Douglas K. Stuver | Retirement | 5 years | 96,764 |

(1) Amounts are computed using assumptions, other than the expected retirement age, consistent with those used in preparing the related pension disclosures in our Notes to Consolidated Financial Statements in Item 8 of this Form 10-K and are as of December 31, 2011, which is the measurement date for the plans. The expected retirement age assumption has been determined in accordance with Instruction 2 to Item 402(h)(2) of Regulation S-K. 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; 35.0% joint and 100% survivor annuity and 15.0% 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 4.90%; an expected retirement age of 60; and postretirement mortality using the RP-2000 table projected to 2022. The present value assumptions used in calculating the present value of accumulated benefits for the Retirement Plan were as follows: a discount rate of 4.90%; an expected retirement age of 65; postretirement mortality using the RP-2000 table projected to 2022; a lump sum interest rate of 4.90%; and lump sum mortality using the Internal Revenue Code §417(e)(3) Applicable Mortality Table for 2013.

(2) The number of years of service and the present value of accumulated benefits for Mr. Dunn represents his service as a PacifiCorp employee only and does not include any vested benefits earned under Kern River Gas Transmission Company, an indirect wholly-owned subsidiary of MEHC.

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, plus amounts due to Retention Agreements entered into in 2000. 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.

We have adopted the Retirement Plan for the majority of our employees, other than employees subject to collective bargaining agreements that do not provide for coverage. 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(l)(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 pay credits to each participant's account of 6.5% (5.0% 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 (where such salary and incentive amounts are reduced for Internal Revenue Code §401 (a)(17) limits). However, the 4.0% portion of the formula was eliminated on August 1, 2009 and therefore for 2009 the 4.0% benefit was based on eligible compensation for the first seven months that exceeded $62,300 (7/12th of $106,800). 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. Effective January 1, 2009, non-union participants were offered the option to continue to receive pay credits in the Retirement Plan as of December 31, 2008 or receive equivalent fixed 401(k) contributions.

Participants in the Retirement Plan are entitled to receive full benefits upon retirement on or after age 65. Such participants are also entitled to receive reduced benefits upon early retirement after age 55 with at least five years of service or when age plus years of service equals 75. Participants in the SERP are entitled to receive full benefits upon retirement on or after age 60. Such participants are also entitled to receive reduced benefits upon early retirement after age 55 with at least five years of SERP participation or after age 50 with at least 15 years of service and five years of SERP participation.

In 2008, non-union employee participants in the Retirement Plan were offered the option to continue to receive pay credits in the Retirement Plan or receive equivalent fixed contributions to the 401(k) plan, with any such election becoming effective January 1, 2009. Messrs. Walje, Reiten and Stuver elected the equivalent fixed 401(k) contribution option and, therefore, no longer receive pay credits in the Retirement Plan; however, they each continue to receive interest credits.

**Nonqualified Deferred Compensation**

The following table sets forth certain information regarding the DCP accounts held by each of our NEOs as of December 31, 2011:

| Name | Executive contributions in 2011 (1) | Registrant contributions in 2011 (2) | Aggregate earnings/(losses) in 2011 | Aggregate withdrawals/ distributions | Aggregate balance as of December 31, 2011 (3) |
|---|---|---|---|---|---|
| Gregory E. Abel | $ — | $ — | $ — | $ — | $ — |
| A. Richard Walje | — | — | (36,535) | 12,201 | 1,971,773 |
| R. Patrick Reiten | — | — | (298) | — | 348,313 |
| Micheal G. Dunn | 13,750 | 15,107 | (291) | — | 54,900 |
| Douglas K. Stuver | — | — | (228) | — | 7,080 |

(1) The Executive contribution amount shown for Mr. Dunn is included in the 2011 total compensation reported for him in the Summary Compensation Table and is not additional earned compensation.

(2) The Registrant contribution amount shown for Mr. Dunn is included in the 2011 total compensation reported for him in the Summary Compensation Table and is not additional earned compensation. The amount was earned in 2011 but not contributed into the DCP until 2012.

(3) The aggregate balance as of December 31, 2011 for Messrs. Walje, Reiten, Dunn and Stuver includes $2,596, $1,960, $13,208 and $1,960, respectively, of compensation previously reported in 2010 in the Summary Compensation Table, and for Messrs. Walje and Stuver includes $5,959 and $5,290, respectively, for 2009. The aggregate balance for Mr. Reiten includes $346,651 of the 2006 LTIP award, which was deferred in 2010 and is not included in the 2011 total compensation reported for him in the Summary Compensation Table.

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 pretax 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 daily, and returns are posted to accounts based on participants' fund allocation elections. Participants can change their fund allocations as of the end of any day on which the market is open.

The DCP allows participants to maintain three accounts based upon when they want to receive payments: retirement account, in-service account and education account. 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

Our NEOs, other than 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, 2011 (File No. 001-14881) for information about potential post-termination payments to Mr. Abel.

The following table sets forth the estimated enhancements to payments pursuant to the termination scenarios indicated. Payments or benefits that are not enhanced in form or amount upon the occurrence of a particular termination scenario, which include 401 (k) and nonqualified deferred compensation account balances and those portions of long-term incentive payments that would have otherwise been paid, are not included herein. All estimated payments reflected in the table below assume termination on December 31, 2011, and are payable as lump sums unless otherwise noted.

| Termination Scenario | Incentive (1) | Pension (2) |
|---|---|---|
| Gregory E. Abel: | | |
| Retirement, Voluntary and Involuntary With or Without Cause | — | — |
| Death and Disability | — | — |
| A. Richard Walje (3): | | |
| Retirement, Voluntary and Involuntary With or Without Cause | — | 72,711 |
| Death and Disability | 707,009 | 72,711 |
| R. Patrick Reiten: | | |
| Retirement, Voluntary and Involuntary With or Without Cause | — | 2,548 |
| Death and Disability | 973,760 | 2,548 |
| Micheal G. Dunn: | | |
| Retirement, Voluntary and Involuntary With or Without Cause | — | 5,220 |
| Death and Disability | 674,753 | 5,220 |
| Douglas K. Stuver: | | |
| Retirement, Voluntary and Involuntary With or Without Cause | — | 4,196 |
| Death and Disability | 370,876 | 4,196 |

(1) Amounts represent the unvested portion of each NEO's LTIP account, which becomes 100% vested upon death or disability. For Mr. Dunn, this represents his unvested portion for service as a PacifiCorp employee only and does not include any additional vesting of awards granted while not employed by us.

(2) Pension values represent the excess of the present value of benefits payable under each termination scenario over the amount already reflected in the Pension Benefits table.

(3) Mr. Walje has already met the retirement criteria, therefore his termination and death scenarios under the Retirement Plan are based on assuming 50% lump sum payout and 50% annuity.

## Director Compensation Table

All of our directors serving in 2011 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 Dunn for whom compensation information is described in the Summary Compensation Table.

| Name | Change in Pension Value and Nonqualified Deferred Compensation Earnings (1) | All Other Compensation (2) | Total |
|---|---|---|---|
| Douglas L. Anderson | $ — | $ — | $ — |
| Brent E. Gale | 28,712 | 780,398 | 809,110 |
| Patrick J. Goodman | — | — | — |
| Natalie L. Hocken | 8,194 | 560,475 | 568,669 |
| Mark C. Moench | 27,157 | 483,772 | 510,929 |

(1) Amounts included in change in pension value and nonqualified deferred compensation earnings are based upon the aggregate increase in the actuarial present value of all qualified and nonqualified defined benefit plans, which includes the Retirement Plan. Amounts are computed using assumptions consistent with those used in preparing the applicable pension disclosures included in our Notes to the Consolidated Financial Statements in Item 8 of this Form 10-K and are as of the pension plans' measurement dates. No participant in our DCP earned "above market" or "preferential" earnings on amounts deferred.

(2) Amounts shown for the year ended December 31, 2011, include:

(i) Base salary in the amounts of $292,750 for Mr. Gale, $194,164 for Ms. Hocken and $222,525 for Mr. Moench.

(ii) Contributions to our 401(k) Plan of $6,622 for Mr. Gale, $26,936 for Ms. Hocken and $11,224 for Mr. Moench.

(iii) Life insurance premium paid by us on behalf of Mr. Gale in the amount of $13,550.

(iv) Performance award of $12,718 to Ms. Hocken for contributions made in 2011.

(v) Annual cash incentive awards earned pursuant to the AIP for our directors, the vesting of LTIP awards and associated vested earnings/(losses) for Mr. Gale, Ms. Hocken and Mr. Moench. The breakout of AIP and LTIP awards for 2011 is as follows:

| | | LTIP | | |
|---|---|---|---|---|
| | AIP | Vested Awards | Vested Earnings/ (Losses) | Total |
| Brent E. Gale | $ 160,000 | $ 282,977 | $ 24,499 | $ 307,476 |
| Natalie L. Hocken | 135,000 | 190,458 | (5,787) | 184,671 |
| Mark C. Moench | 95,000 | 152,469 | 2,447 | 154,916 |

## Compensation Committee Interlocks and Insider Participation

Mr. Abel is our Chairman and CEO and also the Chairman, President and Chief Executive Officer of MEHC. None of our executive officers serves 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 serves 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 Annual Report on Form 10-K.

## Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

We are a consolidated subsidiary of MEHC. Our common stock is indirectly owned by MEHC, 666 Grand Avenue, Des Moines, Iowa 50309. MEHC is a consolidated subsidiary of Berkshire Hathaway that, as of January 31, 2012, owns 89.85% of MEHC's common stock. The balance of MEHC's common stock is owned by Walter Scott, Jr. (along with family members and related entities), a member of MEHC's Board of Directors, 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, 2012 regarding the beneficial ownership of MEHC's common stock and the Class A and Class B shares of Berkshire Hathaway common stock held by each of our directors, executive officers and all of our directors and executive officers as a group as of January 31, 2012.

| | MEHC | | Berkshire Hathaway | | | |
|---|---|---|---|---|---|---|
| | Common Stock | | Class A Common Stock | | 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) | 595,940 | 0.8% | 5 | * | 2,289 | * |
| Douglas L. Anderson | — | — | 4 | * | 300 | * |
| Micheal G. Dunn | — | — | — | — | — | — |
| Brent E. Gale | — | — | — | — | — | — |
| Patrick J. Goodman | — | — | 4 | * | 660 | * |
| Natalie L. Hocken | — | — | — | — | — | — |
| Mark C. Moench | — | — | 3 | * | — | — |
| R. Patrick Reiten | — | — | — | — | — | — |
| Douglas K. Stuver | — | — | — | — | — | — |
| A. Richard Walje | — | — | — | — | — | — |
| All executive officers and directors as a group (10 persons) | 595,940 | 0.8% | 16 | * | 3,249 | * |

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

(1) Includes shares 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, 2012, Mr. Abel would be entitled to exchange his shares of MEHC common stock for either 1,120 shares of Berkshire Hathaway Class A stock or 1,676,651 shares of Berkshire Hathaway Class B stock. Assuming an exchange of all available MEHC shares into either Berkshire Hathaway Class A shares or Berkshire Hathaway Class B shares, Mr. Abel would beneficially own less than 1% of the outstanding shares of either class of stock.

### 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

### Certain Relationships and Related Transactions

The Berkshire Hathaway Inc. 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 costs 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 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 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 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 LLC, on which the common stock of our ultimate parent company, Berkshire Hathaway, is listed, our Board of Directors has determined that none of our directors are considered independent because of their employment by MEHC or PacifiCorp.

### Item 14. Principal Accountant Fees and Services

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):

| | 2011 | 2010 |
|---|---|---|
| Audit fees(1) | $ 1.4 | $ 1.4 |
| Audit-related fees(2) | 0.3 | 0.2 |
| Tax fees(3) | — | — |
| All other fees | — | — |
| Total | $ 1.7 | $ 1.6 |

(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 has considered whether the non-audit services provided to PacifiCorp by the Deloitte Entities impaired the independence of the Deloitte Entities and concluded that they did not. All of the services performed by the Deloitte Entities were pre-approved in accordance with the pre-approval policy adopted by the audit committee of MEHC. The policy provides guidelines for the audit, audit-related, tax and other non-audit services that may be provided by the Deloitte Entities to PacifiCorp. The policy (a) identifies the guiding principles that must be considered by the audit committee of MEHC in approving services to ensure that the Deloitte Entities' independence is not impaired; (b) describes the audit, audit-related and tax services that may be provided and the non-audit services that are prohibited; and (c) sets forth pre-approval requirements for all permitted services. Under the policy, requests to provide services that require specific approval by the audit committee of MEHC will be submitted to the audit committee of MEHC by both PacifiCorp's independent auditor and MEHC's Chief Financial Officer. All requests for services to be provided by the independent auditor that do not require specific approval by the audit committee of MEHC will be submitted to MEHC's Chief Financial Officer and must include a detailed description of the services to be rendered. MEHC's Chief Financial Officer will determine whether such services are included within the list of services that have received the general pre-approval of the audit committee of MEHC. The audit committee of MEHC will be informed on a timely basis of any such services rendered by the independent auditor.

## PART IV

**Item 15. Exhibits and Financial Statement Schedules**

(a) Financial Statements and Schedules

(i) Financial Statements:
Consolidated 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 on 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 2012.

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<br>Gregory E. Abel | Chairman of the Board of Directors and Chief Executive Officer (principal executive officer) | February 27, 2012 |
| /s/ Douglas K. Stuver<br>Douglas K. Stuver | Senior Vice President and Chief Financial Officer (principal financial and accounting officer) | February 27, 2012 |
| /s/ Douglas L. Anderson<br>Douglas L. Anderson | Director | February 27, 2012 |
| /s/ Micheal G. Dunn<br>Micheal G. Dunn | Director | February 27, 2012 |
| /s/ Brent E. Gale<br>Brent E. Gale | Director | February 27, 2012 |
| /s/ Patrick J. Goodman<br>Patrick J. Goodman | Director | February 27, 2012 |
| /s/ Natalie L. Hocken<br>Natalie L. Hocken | Director | February 27, 2012 |
| /s/ Mark C. Moench<br>Mark C. Moench | Director | February 27, 2012 |
| /s/ R. Patrick Reiten<br>R. Patrick Reiten | Director | February 27, 2012 |
| /s/ A. Richard Walje<br>A. Richard Walje | Director | February 27, 2012 |

## EXHIBIT INDEX

| Exhibit No. | Description |
|---|---|
| 3.1* | Third Restated Articles of Incorporation of PacifiCorp (Exhibit (3)a, 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 The Bank of New York Mellon Trust Company, N.A., Trustee, incorporated by reference to Exhibit 4-E, Form 8-B, File No. 1-5152, as supplemented and modified by 25 Supplemental Indentures, each incorporated by reference, 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 |
| 4.1 | 8-K | May 12, 2011 | 1-5152 |
| 4.1 | 8-K | January 6, 2012 | 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 listed on the signatures pages thereto, The Royal Bank of Scotland plc, as Syndication Agent, and Union Bank, N.A. (formerly known as 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 listed on the signatures pages thereto, 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). |
| 10.8* | First Amendment dated as of April 15, 2009, amends that certain Credit Agreement, dated as of October 23, 2007, among PacifiCorp, the banks listed on the signatures pages thereto, the Royal Bank of Scotland plc, as Syndication Agent and Union Bank, N.A., (formerly known as Union Bank of California, N.A.), as Administrative Agent. (Exhibit 10.1, Quarterly Report on Form 10-Q, filed May 8, 2009, File No. 1-5152). |
| 10.9* | First Amendment dated as of April 15, 2009, amends that certain Amended and Restated Credit Agreement, dated as of July 6, 2006, among PacifiCorp, the banks listed on the signature pages thereto, JPMorgan Chase Bank, N.A. as Administrative Agent and Issuing Bank, and the Royal Bank of Scotland plc, as Syndication Agent. (Exhibit 10.2, Quarterly Report on Form 10-Q, filed May 8, 2009, File No. 1-5152). |
| 10.10*† | Amendment No. 1 to the PacifiCorp Executive Voluntary Deferred Compensation Plan dated October 28, 2008. |
| 10.11 | Second Amendment dated as of January 6, 2012, amends that certain Amended and Restated Credit Agreement, dated as of July 6, 2006, among PacifiCorp, the banks listed on the signature pages thereto, JPMorgan Chase Bank, N.A., as Administrative Agent and Issuing Bank, and the Royal Bank of Scotland plc, as Syndication Agent. |
| 12.1 | Statements of Computation of Ratio of Earnings to Fixed Charges. |
| 12.2 | Statements of Computation of Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends. |
| 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. |
| 95 | Coal Mine Safety Disclosures Required by the Dodd-Frank Wall Street Reform and Consumer Protection Act. |
| 101 | The following financial information from PacifiCorp's Annual Report on Form 10-K for the year ended December 31, 2011 is formatted in XBRL (eXtensible Business Reporting Language) and included herein: (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Operations, (iii) the Consolidated Statements of Cash Flows, (iv) the Consolidated Statements of Changes in Equity, (v) the Consolidated Statements of Comprehensive Income and (vi) the Notes to Consolidated Financial Statements, tagged as blocks of text. |

*Incorporated herein by reference.
†Management contract or compensatory plan.

**EXHIBIT 10.1**

## SUMMARY OF KEY TERMS OF COMPENSATION ARRANGEMENTS WITH PACIFICORP'S NAMED EXECUTIVE OFFICERS AND DIRECTORS

PacifiCorp's named executive officers (other than its Chairman and Chief Executive Officer, Greg Abel) and its other employee directors each receive an annual salary and participate in health insurance and other benefit plans on the same basis as other employees, as well as certain other compensation and benefit plans described in PacifiCorp's Annual Report on Form 10-K. Mr. Abel is employed by PacifiCorp's parent company, MidAmerican Energy Holdings Company ("MEHC") and is not directly compensated by PacifiCorp. PacifiCorp reimburses 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.

The named executive officers and directors are also eligible to receive a cash incentive award under PacifiCorp's Annual Incentive Plan ("AIP"). The AIP provides for a discretionary annual cash award that is determined on a subjective basis and paid in December. In addition to the AIP, the named executive officers are eligible to receive discretionary cash performance awards periodically during the year to reward the accomplishment of significant non-recurring tasks or projects. The named executive officers and directors are participants in MEHC's Long-Term Incentive Partnership Plan ("LTIP"). A copy of the LTIP is attached as Exhibit 10.9 to the MEHC Annual Report on Form 10-K for the year ended December 31, 2011 and incorporated by reference herein.

Base salary for named executive officers and employee directors for PacifiCorp's fiscal year ending December 31, 2012 (excluding Mr. Abel) is shown in the following table:

| Name and Title | Base Salary |
|---|---|
| Douglas K. Stuver<br>Senior Vice President and Chief Financial Officer | $ 244,055 |
| A. Richard Walje<br>President and Chief Executive Officer, Rocky Mountain Power | 368,000 |
| R. Patrick Reiten<br>President and Chief Executive Officer, Pacific Power | 300,000 |
| Micheal G. Dunn<br>President and Chief Executive Officer, PacifiCorp Energy | 300,000 |
| Brent E. Gale<br>Director | 292,750 |
| Natalie L. Hocken<br>Director | 198,533 |
| Mark C. Moench<br>Director | 228,225 |

Messrs. Walje, Reiten, Dunn, Gale and Moench and Ms. Hocken are directors of PacifiCorp, but do not receive additional compensation for their service as directors other than what they receive as employees of PacifiCorp. Messrs. Abel, Anderson and Goodman are employees of MEHC, but do not receive additional compensation for their service as directors other than what they receive as employees of MEHC.

**EXHIBIT 12.1**

PACIFICORP
STATEMENTS OF COMPUTATION OF RATIO
OF EARNINGS TO FIXED CHARGES
(DOLLARS IN MILLIONS)

| | Years Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2011 | 2010 | 2009 | 2008 | 2007 |
| Earnings Available for Fixed Charges: | | | | | |
| Income from continuing operations before income tax expense | $ 768 | $ 777 | $ 784 | $ 703 | $ 665 |
| Add: | | | | | |
| Fixed charges | 397 | 392 | 398 | 349 | 322 |
| Deduct: | | | | | |
| Net income attributable to noncontrolling interest in subsidiary that has not incurred fixed charges | — | — | (8) | (7) | (6) |
| Total earnings available for fixed charges | $ 1,165 | $ 1,169 | $ 1,174 | $ 1,045 | $ 981 |
| Fixed Charges: | | | | | |
| Interest expense | $ 392 | $ 387 | $ 394 | $ 343 | $ 314 |
| Estimated interest portion of rentals charged to expense | 5 | 5 | 4 | 6 | 8 |
| Total fixed charges | $ 397 | $ 392 | $ 398 | $ 349 | $ 322 |
| Ratio of Earnings to Fixed Charges | 2.9x | 3.0 x | 2.9 x | 3.0 x | 3.0 x |

**EXHIBIT 12.2**

# PACIFICORP
## STATEMENTS OF COMPUTATION OF RATIO OF EARNINGS TO COMBINED FIXED CHARGES AND PREFERRED STOCK DIVIDENDS
## (DOLLARS IN MILLIONS)

| | Years Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2011 | 2010 | 2009 | 2008 | 2007 |
| Earnings Available for Fixed Charges: | | | | | |
| Income from continuing operations before income tax expense | $ 768 | $ 777 | $ 784 | $ 703 | $ 665 |
| Add: | | | | | |
| Fixed charges | 397 | 392 | 398 | 349 | 322 |
| Deduct: | | | | | |
| Net income attributable to noncontrolling interest in subsidiary that has not incurred fixed charges | — | — | (8) | (7) | (6) |
| Total earnings available for fixed charges | $ 1,165 | $ 1,169 | $ 1,174 | $ 1,045 | $ 981 |
| Fixed Charges and Preferred Stock Dividends: | | | | | |
| Interest expense | $ 392 | $ 387 | $ 394 | $ 343 | $ 314 |
| Estimated interest portion of rentals charged to expense | 5 | 5 | 4 | 6 | 8 |
| Total fixed charges | 397 | 392 | 398 | 349 | 322 |
| Preferred stock dividends [1] | 3 | 3 | 3 | 3 | 3 |
| Total fixed charges and preferred stock dividends | $ 400 | $ 395 | $ 401 | $ 352 | $ 325 |
| Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends | 2.9x | 3.0 x | 2.9 x | 3.0 x | 3.0 x |

(1) Represents actual preferred stock dividends grossed up for income taxes.

EXHIBIT 23.1

## CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-170954 on Form S-3ASR of our report dated February 27, 2012, relating to the consolidated financial statements of PacifiCorp and subsidiaries appearing in this Annual Report on Form 10-K of PacifiCorp for the year ended December 31, 2011.

/s/ Deloitte & Touche LLP
Deloitte & Touche LLP

Portland, Oregon
February 27, 2012

**EXHIBIT 31.1**

**CERTIFICATION PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002**

I, Gregory E. Abel, certify that:

1. I have reviewed this Annual Report on Form 10-K of PacifiCorp;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2012

/s/ Gregory E. Abel
Gregory E. Abel
Chairman of the Board of Directors and Chief Executive Officer
(principal executive officer)

**EXHIBIT 31.2**

**CERTIFICATION PURSUANT TO**
**SECTION 302 OF THE**
**SARBANES-OXLEY ACT OF 2002**

I, Douglas K. Stuver, certify that:

1. I have reviewed this Annual Report on Form 10-K of PacifiCorp;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 27, 2012

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

**EXHIBIT 32.1**

## CERTIFICATION PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

I, Gregory E. Abel, Chairman of the Board of Directors and Chief Executive Officer of PacifiCorp, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of the Company for the annual period ended December 31, 2011 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o (d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

Date: February 27, 2012

/s/ Gregory E. Abel
Gregory E. Abel
Chairman of the Board of Directors and Chief Executive Officer
(principal executive officer)

**EXHIBIT 32.2**

**CERTIFICATION PURSUANT TO**
**SECTION 906 OF THE**
**SARBANES-OXLEY ACT OF 2002**

I, Douglas K. Stuver, Senior Vice President and Chief Financial Officer of PacifiCorp, certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Annual Report on Form 10-K of the Company for the annual period ended December 31, 2011 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o (d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

Date: February 27, 2012

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

EXHIBIT 95

# MINE SAFETY VIOLATIONS AND OTHER LEGAL MATTER DISCLOSURES PURSUANT TO SECTION 1503(a) OF THE DODD-FRANK WALL STREET REFORM AND CONSUMER PROTECTION ACT

PacifiCorp and its subsidiaries operate certain coal mines and coal processing facilities (collectively, the "mining facilities") that are regulated by the Federal Mine Safety and Health Administration ("MSHA") under the Federal Mine Safety and Health Act of 1977 (the "Mine Safety Act"). MSHA inspects PacifiCorp's mining facilities on a regular basis. The total number of reportable Mine Safety Act citations, orders, assessments and legal actions for the year ended December 31, 2011 are summarized in the table below and are subject to contest and appeal. The severity and assessment of penalties may be reduced or, in some cases, dismissed through the contest and appeal process. Amounts are reported regardless of whether PacifiCorp has challenged or appealed the matter. Coal reserves that are not yet mined and mines that are closed or idled are not included in the information below as no reportable events occurred at those locations during the year ended December 31, 2011. There were no mining-related fatalities during the year ended December 31, 2011.

| | Mine Safety Act | | | Legal Actions | | |
|---|---|---|---|---|---|---|
| Coal Mine | Section 104 Significant and Substantial Citation[1] | Section 104(b) Orders[2] | Total Value of Proposed MSHA Assessments (in thousands) | Pending[3] | Instituted During Period | Closed During Period |
| Deer Creek | 18 | — | $ 38 | 12 | 9 | 14 |
| Bridger (surface) | 6 | — | 10 | 4 | 3 | 5 |
| Bridger (underground) | 43 | 1 | 155 | 17 | 11 | 11 |
| Cottonwood Preparatory Plant | 1 | — | — | — | — | — |
| Wyodak Coal Crushing Facility | — | — | — | — | — | — |

(1) Citations for alleged violations of mandatory health and safety standards that could significantly or substantially contribute to the cause and effect of a safety or health hazard under Section 104 of the Mine Safety Act.

(2) For alleged failure to totally abate the subject matter of a Mine Safety Act Section 104(a) citation within the period specified in the citation. This order was abated on May 10, 2011.

(3) Amounts are as of December 31, 2011 and (a) include contests of proposed penalties under Subpart C of the Federal Mine Safety and Health Review Commission's procedural rules and (b) are not exclusive to citations, notices, orders and penalties assessed by MSHA during the reporting period.