ORIGINAL

PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

825 NE Multnomah, Suite1900
Portland, Oregon 97232-2135

March 19, 2013

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

Docket No. 13-999-01

Dear Commission:

Enclosed is a copy of PacifiCorp's most recent annual report on Form 10-K for the period ended December 31, 2012, as filed with the Securities and Exchange Commission pursuant to the requirement of the Securities Exchange Act of 1934.

Very Truly Yours,

Elizabeth Craven

Elizabeth Craven
External Reporting Manager

Enclosure

ORIGINAL

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, 2012

or

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

For the transition period from _____ to _____

Commission File Number	Exact name of registrant as specified in its charter; State or other jurisdiction of incorporation or organization	IRS Employer Identification No.
1-5152	**PACIFICORP** **(An Oregon Corporation)** **825 N.E. Multnomah Street** **Portland, Oregon 97232** **503-813-5608**	**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 (None Outstanding)

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, Suite 500, Des Moines, Iowa 50309-2580. As of January 31, 2013, 357,060,915 shares of common stock were outstanding.

TABLE OF CONTENTS

Definition of Abbreviations and Industry Terms

When used in Forward-Looking Statements, Part I - Items 1 through 4, Part II - Items 5 through 7A and Items 9 through 9B, and Part III - Items 10 and 14, 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
Dodd-Frank Reform Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
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
FIP	Federal Implementation Plan
GHG	Greenhouse Gases
GHG Reporting	Greenhouse Gases Reporting
GWh	Gigawatt Hours
IPUC	Idaho Public Utilities Commission
IRP	Integrated Resource Plan
kV	Kilovolt
MATS	Mercury and Air Toxics Standard
MSHA	Federal Mine Safety and Health Administration
MW	Megawatts
MWh	Megawatt Hours
NERC	North American Electric Reliability Corporation
OPUC	Oregon Public Utility Commission
PCAM	Power Cost Adjustment Mechanism
PTAM	Post Test-year Adjustment Mechanism
RCRA	Resource Conservation and Recovery Act
REC	Renewable Energy Credit
RRA	Renewable Energy Credit and Sulfur Dioxide Revenue Adjustment Mechanism
RFPs	Requests for Proposals
RPS	Renewable Portfolio Standards
SEC	United States Securities and Exchange Commission
SIP	State Implementation Plan
TAM	Transition Adjustment Mechanism

Certain Industry Terms (continued)

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 or generation that could impact PacifiCorp's hedging strategy and the cost of balancing its generation resources with its retail load obligations;

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

- hydroelectric conditions and the cost, feasibility and eventual outcome of hydroelectric relicensing proceedings, that could have a significant impact on generating 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 PacifiCorp's 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 pension and other postretirement benefits expense and funding requirements;

- unanticipated construction delays, changes in costs, receipt of required permits and authorizations, ability to fund capital projects and other factors that could affect future generating facilities and infrastructure additions;

- the impact of new accounting 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, fires, 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 utility company serving 1.8 million retail customers, including residential, commercial, industrial, irrigation 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 10,579 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 to balance and optimize the economic benefits of electricity generation, retail loads and existing wholesale transactions. PacifiCorp is subject to comprehensive state and federal regulation. PacifiCorp's subsidiaries support its electric utility operations by providing coal mining 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

MEHC and Berkshire Hathaway entered into an Equity Commitment Agreement (the "Berkshire Equity Commitment") pursuant to which Berkshire Hathaway has agreed to purchase up to $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 645-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. PacifiCorp also continues to invest in its transmission system to improve system reliability, integrate and access generation resources, reduce transmission system constraints and address customer load growth.

Employees

As of December 31, 2012, PacifiCorp had approximately 6,300 employees, of which approximately 3,700 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

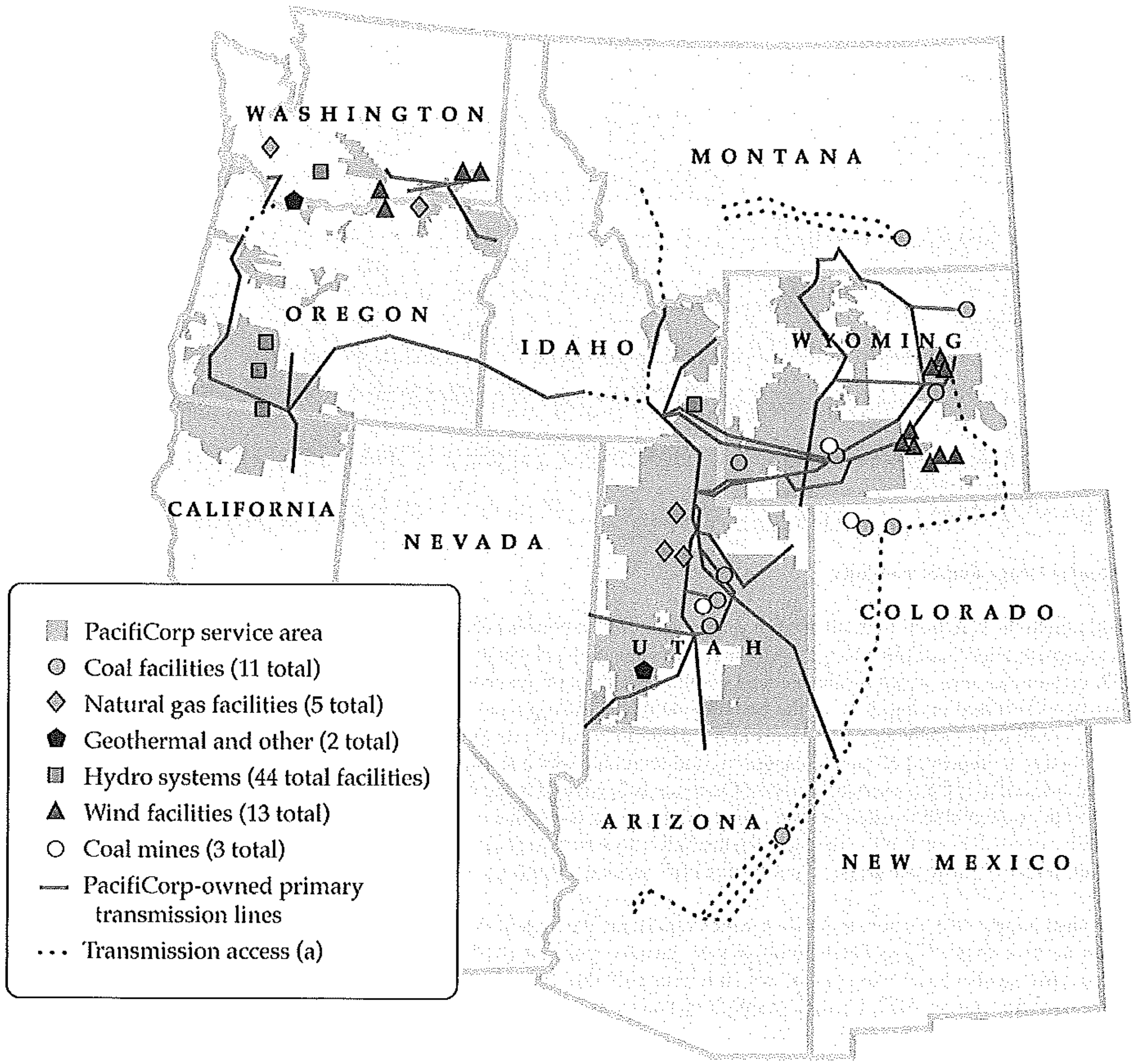
PacifiCorp's combined service territory covers approximately 136,000 square miles and includes diverse regional economies. No single segment of the economy dominates the service territory, which helps mitigate PacifiCorp's exposure to economic fluctuations. In the eastern portion of the service territory, consisting of Utah, Wyoming and southeastern Idaho, the principal industries are manufacturing, mining or extraction of natural resources, agriculture, technology, recreation and government. 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, government 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 29 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 for the years ended December 31 were as follows:

	2012		2011		2010	
Utah	23,930	44 %	23,245	43 %	22,477	42 %
Oregon	12,779	23	13,014	24	12,717	24
Wyoming	9,498	17	9,793	18	9,680	18
Washington	4,042	7	4,006	7	3,985	8
Idaho	3,518	7	3,440	6	3,326	6
California	782	2	809	2	831	2
	54,549	100 %	54,307	100 %	53,016	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, 2012. 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 and the average number of retail customers for the years ended December 31 were as follows:

	2012		2011		2010	
GWh sold:						
Residential	15,968	24%	16,046	25%	15,795	24%
Commercial	16,829	25	16,489	25	15,969	25
Industrial and irrigation	21,317	32	21,229	32	20,680	32
Other	435	1	543	1	572	1
Total retail	54,549	82	54,307	83	53,016	82
Wholesale	11,870	18	10,767	17	11,415	18
Total GWh sold	66,419	100%	65,074	100%	64,431	100%
Average number of retail customers (in thousands):						
Residential	1,504	86%	1,483	85%	1,475	85%
Commercial	212	12	221	13	220	13
Industrial and irrigation	34	2	34	2	34	2
Other	4	—	4	—	4	—
Total	1,754	100%	1,742	100%	1,733	100%
Retail customers:						
Average usage per customer (kilowatt hours)	31,100		31,175		30,595	
Average revenue per customer	$ 2,455		$ 2,331		$ 2,142	
Revenue per kilowatt hour	7.9¢		7.5¢		7.0¢	

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 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. Customer usage levels in the eastern side of PacifiCorp's service territory improved during 2011 and 2012 primarily due to improved economic conditions and favorable weather. The declining usage trend continued during 2010 in the western side of PacifiCorp's service territory. Customer usage levels in the western side of PacifiCorp's service territory improved in 2011 due to favorable weather despite continued declining usage due to the effects of the economic conditions, which began to stabilize in 2012. In addition, certain large industrial customers with generation capabilities have begun to self-generate, resulting in lower industrial customer usage across PacifiCorp's service territories.

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 2012, PacifiCorp's peak demand was 9,831 MW in the summer and 8,584 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 the impacts of 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, 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, 2012:

	Location	Energy Source	Installed	Facility Net Capacity (MW)(1)	Net Owned Capacity (MW)(1)
COAL:					
Jim Bridger Nos. 1, 2, 3 and 4	Rock Springs, WY	Coal	1974-1979	2,111	1,407
Hunter Nos. 1, 2 and 3	Castle Dale, UT	Coal	1978-1983	1,352	1,147
Huntington Nos. 1 and 2	Huntington, UT	Coal	1974-1977	909	909
Dave Johnston Nos. 1, 2, 3 and 4	Glenrock, WY	Coal	1959-1972	762	762
Naughton Nos. 1, 2 and 3 (2)	Kemmerer, WY	Coal	1963-1971	687	687
Cholla No. 4	Joseph City, AZ	Coal	1981	395	395
Wyodak No. 1	Gillette, WY	Coal	1978	335	268
Carbon Nos. 1 and 2 (3)	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
				9,512	6,139
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: (4)					
Lewis River System (5)	WA	Hydroelectric	1931-1958	578	578
North Umpqua River System (6)	OR	Hydroelectric	1950-1956	204	204
Klamath River System (7)	CA, OR	Hydroelectric	1903-1962	170	170
Bear River System (8)	ID, UT	Hydroelectric	1908-1984	105	105
Rogue River System (9)	OR	Hydroelectric	1912-1957	52	52
Minor hydroelectric facilities	Various	Hydroelectric	1895-1986	36	36
				1,145	1,145
WIND: (4)					
Marengo	Dayton, WA	Wind	2007	140	140
Dunlap Ranch I	Medicine Bow, WY	Wind	2010	111	111
Leaning Juniper 1	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: (4)					
Blundell	Milford, UT	Geothermal	1984, 2007	34	34
Camas Co-Gen	Camas, WA	Black liquor	1996	14	14
				48	48
Total available generating capacity				14,198	10,579
PROJECTS UNDER CONSTRUCTION: (10)					
Lake Side 2	Vineyard, UT	Natural gas/steam		645	645
				14,843	11,224

(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) PacifiCorp currently plans to convert Naughton Unit No. 3 to a natural gas-fueled unit. Refer to "Regulatory Matters" in Item 7 of this Form 10-K.

(3) PacifiCorp currently anticipates retiring the Carbon coal-fueled generating facility in early 2015. Refer to "Regulatory Matters" and "Environmental Laws and Regulations" in Item 7 of this Form 10-K.

(4) 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 RECs or other environmental commodities.

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

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

(7) 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.

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

(9) 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.

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

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

	2012	2011	2010
Coal	60 %	59 %	62 %
Natural gas	10	9	12
Hydroelectric (1)	6	7	5
Wind and other (1)	5	5	5
Total energy generated	81	80	84
Energy purchased - short-term contracts and other	12	12	8
Energy purchased - long-term contracts	7	8	8
	100 %	100 %	100 %

(1) 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 RECs or other environmental commodities.

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 30%, 28% and 29% of PacifiCorp's total coal requirements during the years ended December 31, 2012, 2011 and 2010, 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 through the federal 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, 2012, based on 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	29	(1)
Bridger	Rock Springs, WY	Jim Bridger	Underground	46	(1)
Deer Creek	Huntington, UT	Huntington, Hunter and Carbon	Underground	26	(2)
Trapper	Craig, CO	Craig	Surface	6	(3)
				107	

(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. The coal lease contains an estimated 47 million tons of recoverable coal available to supply PacifiCorp's coal-fueled generating facilities in Utah in the future.

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.

Natural Gas

PacifiCorp uses natural gas as fuel for its combined- and simple-cycle natural gas-fueled generating facilities and for the Gadsby Steam generating facility. Oil and natural gas are also used for igniter fuel 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 with both fixed and indexed 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 and complying with laws and regulations. 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. PacifiCorp's wind-powered generating facilities are eligible for federal renewable electricity production tax credits for 10 years from the date the facilities are placed in service. Production tax credits for PacifiCorp's currently eligible wind-powered generating facilities will begin expiring in 2016, with final expiration in 2020.

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.

In February 2013, PacifiCorp and the California Independent System Operator Corporation ("California ISO") entered into a non-binding memorandum of understanding in an effort to create a real-time energy imbalance market in the West. PacifiCorp is not joining the California ISO as a participating transmission owner and will retain full control of its transmission and other assets. If implemented, PacifiCorp would participate in a co-optimized real-time energy market facilitated by the California ISO's existing operating systems, which is intended to reduce costs for customers, enhance reliability, more effectively integrate renewable resources and lead to a greater coordination across the region. PacifiCorp expects a binding agreement between the parties to be filed with the FERC during the second quarter of 2013. The draft milestone schedule in the memorandum of understanding targets October 2014 as the date the energy imbalance market will open for initial participation.

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, 2012, 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, 2012. 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 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 over the next several years, 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, 2012, $1.4 billion had been spent and $890 million, including 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. The OPUC acknowledged PacifiCorp's 2011 IRP as modified by the updated action plan in March 2012 with exceptions and guidance for PacifiCorp's next IRP. PacifiCorp filed its 2011 IRP update with the OPUC, the UPSC, the WPSC and the WUTC in March 2012 and with the IPUC in April 2012. PacifiCorp plans to file its 2013 IRP with the state commissions in early 2013.

Requests for Proposals

PacifiCorp has issued individual RFPs, each of which focuses on a specific category of 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, as applicable, 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.

In September 2012, PacifiCorp terminated its All Source RFP for a 2016 resource with the UPSC and OPUC as a result of lower forecasted retail load growth. The All Source RFP sought up to 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.

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. During 2012, PacifiCorp spent $120 million on these DSM programs, resulting in an estimated 544,590 MWh of first-year energy savings and an estimated 357 MW of peak load management. 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, depending on the customers' actual loads. Recovery of the costs associated with the large industrial load management program is determined through PacifiCorp's general rate case process.

General Regulation

PacifiCorp is subject to comprehensive governmental regulation, which significantly influences its operating environment, prices charged to customers, capital structure, costs and, ultimately, PacifiCorp's ability to recover costs. In addition to the following discussion, refer to "Regulatory Matters" in Item 7 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 each state regulatory commission deems to be the utility's reasonable costs of providing services, including a fair opportunity to earn a reasonable return on its investments based on its cost of debt and equity. In addition to return on investment, a utility's cost of service generally reflects a representative level of prudent expenses, including energy costs, operation and maintenance expense, depreciation and amortization expense and income and other tax expense, reduced by wholesale electricity and other revenue. The allowed operating expenses are typically based on actual historical costs adjusted for known and measurable or forecasted changes. State regulatory commissions may adjust rates for various reasons, including pursuant to a review of: (a) the utility's revenue and expenses during a defined test period and (b) the utility's level of investment. 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 customers or organizations representing groups 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 energy cost adjustment mechanisms and other cost recovery mechanisms in certain states, 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 electricity distribution services to all residential 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.
		Beginning January 1, 2013, a PCAM under which 90% of the difference between forecasted net variable power costs set under the annual TAM and actual net variable power costs is deferred and reflected in future rates. The difference between the forecasted and actual net variable power costs must fall outside of an established asymmetrical deadband range and is also subject to an earnings test.
		Renewable Adjustment Clause to recover the revenue requirement of new renewable resources and associated transmission costs 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 credit 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 revenues included in base rates and actual REC revenues and 90% of the level of sulfur dioxide revenues included in base rates and actual 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 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 and records retention; 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 and procedures that facilitate and monitor compliance with the FERC's regulations described below.

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's authority to sell electricity in wholesale electricity markets at market-based rates 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 by 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 mandatory reliability standards developed by the NERC and the WECC, including planning and operation, critical infrastructure protection and regional standards. Compliance, enforcement and monitoring oversight of these standards is carried out by the FERC, the NERC and the WECC.

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. 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 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 focused on sediment monitoring as material moved downstream into the Columbia River. Removal of project facilities commenced in January 2012 and dam removal was completed in September 2012. Restoration of the site is ongoing. Post project monitoring of water quality and sediment deposition continues as per the Washington Department of Ecology Clean Water Act 401 certificate requirements.

United States Mine Safety

PacifiCorp's mining operations are regulated by 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 mine 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 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 "Environmental Laws and Regulations" in Item 7 of this Form 10-K for additional information regarding environmental laws and regulations and "Liquidity and Capital Resources" for 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 we currently deem immaterial may also impair our business operations.

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 and maintaining generating facilities and transmission and distribution system assets; setting rates charged to customers; establishing capital structures and issuing debt or equity securities; transacting with affiliates; and paying dividends or similar distributions. 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.

Compliance with applicable laws and regulations generally requires us to obtain and comply with a wide variety of licenses, permits, inspections, audits 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 refunds, 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 or otherwise uneconomical. As a result, we could be required to shut down some facilities 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 or favorably locating new facilities or expanding existing 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 electricity generating facilities are operated that may adversely impact generation. 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; the implementation of energy efficiency mandates; the issuance of regulations over the management and disposal of coal combustion byproducts; changes in forecasting requirements; 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 from time to time that impose additional or new requirements or standards on our business.

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 accurately predict the type or scope of future laws and regulations that may be enacted, changes in existing ones or new interpretations by agency orders or court decisions nor can we determine their impact on us at this time; however, any one of these could adversely affect our consolidated financial results through higher capital expenditures and operating costs or restrict or otherwise cause an adverse 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 costs of complying with such 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 while also requiring us to ensure system reliability. Decisions are subject to judicial 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 recovered through rates 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 it deems are just and reasonable in providing the service and may disallow recovery in rates for any costs that it believes 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 Washington, we are currently 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 authorizes cost-based rates associated with transmission services provided by our transmission facilities. 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 also maintains rules concerning standards of conduct, interlocking directorates and cross-subsidization. The FERC may also impose substantial civil penalties for any non-compliance with the Federal Power Act and the FERC's rules and orders.

The NERC has standards in place to ensure the reliability of the electric transmission grid and generation system. PacifiCorp is subject to the NERC's regulations and periodic audits to ensure compliance with those regulations. The NERC may carry out enforcement actions for non-compliance and administer significant financial penalties, subject to the FERC's review.

We are subject to operating uncertainties, including costs to maintain, repair and replace utility systems and occurrences of catastrophic events, which could adversely affect our consolidated financial results.

The operation of complex utility 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 outages; strikes, lockouts or other labor-related actions; shortage of qualified labor; transmission and distribution system constraints; cyberattacks; 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; design, construction or manufacturing defects; and catastrophic events such as severe storms, floods, fires, earthquakes and mining accidents. A catastrophic event might result in injury or loss of life, extensive property damage or environmental damage. Any of these events or other operational events 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.

We are actively pursuing, developing and constructing new or expanded facilities, the completion and expected costs 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 electricity generating facilities, 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 changes in environmental and operational compliance matters, load forecasts 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 rates 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 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 serve retail loads.

A significant sustained decrease in demand for electricity in the markets served by us would significantly decrease our operating revenue and could adversely affect our consolidated financial results.

A significant sustained decrease in demand for electricity in the markets served by us would significantly reduce our operating revenue and could 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;
- 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;
- 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; and
- sustained mild weather that reduces heating or cooling needs.

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 provided 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 our wholesale sale contracts.

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 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 fluctuations in generation 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 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. Although we have energy cost adjustment mechanisms in most states, the risks associated with changes in market prices are not fully mitigated due to customer sharing bands and other factors.

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, our 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 form of security for existing transactions and as a condition to entering into future transactions with us. Such amounts may be material and may adversely affect our liquidity and cash flows.

Potential terrorist activities and the impact of military or other actions, including cyberattacks, could adversely affect our consolidated financial results.

The ongoing threat of terrorism and the impact of military and other actions by nations and politically, ethnically, or religiously motivated organizations regionally or globally may create increased political, economic, social and financial market instability, which could subject our operations to increased risks. Additionally, the United States government has issued warnings that energy assets, specifically electric utility infrastructure are potential targets for terrorist organizations. Cyberattacks could adversely affect our ability to operate our facilities, information technology and business systems, or compromise confidential customer and employee information. Political, economic, social or financial market instability or damage to or interference with 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, and increased security, repair or other costs, any of which 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 cyberattacks, or war could also materially adversely affect our ability to raise capital.

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 payment 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 meet their payment obligations. We depend on these counterparties to remit payments on a timely basis. We continue to monitor the creditworthiness of our 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 suppliers' and customers' financial condition deteriorates or they otherwise become unable to pay, it could have a significant adverse impact on 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.

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

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

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.

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. Significant dislocations and liquidity disruptions in the United States and global credit markets, as occurred in 2008 and 2009, may materially impact liquidity in the bank and debt capital markets, making financing terms less attractive for borrowers that are able to find financing and, in other cases, may cause certain types of debt financing, or any financing, to be unavailable. Additionally, economic uncertainty in the United States or globally may adversely affect the United States' credit markets and could 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.

Poor performance of plan and fund investments and other factors impacting the pension and other postretirement benefit plans and mine reclamation trust funds could unfavorably impact our consolidated financial results.

Costs of providing our defined benefit pension and other postretirement benefit plans, including costs associated with the joint trustee and multiemployer plans to which we and our subsidiary contribute, respectively, depend upon a number of factors, including the rates of return on plan assets, the level and nature of benefits provided, assumed 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 joint trustee and multiemployer plans to which we and our subsidiary contribute, respectively, are in underfunded positions. Even if sustained growth in the investments over future periods increases the value of these plans' assets, we will likely be required to make significant cash contributions to fund these plans in the future. Our subsidiary may also be required to make higher cash contributions to the multiemployer plan as a result of funding improvement plans. To the extent a mass withdrawal from any of the multiemployer plans to which we or our subsidiary have contributed occurs, we or our subsidiary may be subject to a mass withdrawal liability associated with respective unfunded vested benefits even if we or our subsidiary voluntarily withdrew from the plan up to three years prior to the mass withdrawal. To the extent participating employers default on their obligations to the multiemployer plan to which our subsidiary contributes, our subsidiary could be subject to an allocation of respective unfunded vested benefits associated with those employers' obligations. The multiemployer plan to which our subsidiary contributes covers employees and retirees associated with certain of our mining operations; to the extent the mining operations cease, our subsidiary may be subject to a withdrawal liability. Our pension and other postretirement benefit plans have investments in domestic and foreign equity and debt securities and other investments that are subject to loss. Losses from investments could add to the volatility, size 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 a variety of legal proceedings, the outcomes of which are uncertain and could adversely affect our consolidated financial results.

We are, and in the future may become, a party to a variety of legal proceedings. Litigation is subject to many uncertainties, and we cannot predict the outcome of individual matters with certainty. It is possible that the final resolution of some of the matters in which we are involved could result in additional payments substantially in excess of established reserves 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, or divest ownership of assets, 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 and adverse regulatory consequences, any of 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.

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.

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

Not applicable.

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

Headquarters/Offices

PacifiCorp's corporate offices consist of approximately 800,000 square feet of owned and leased office space located in several buildings in Portland, Oregon and Salt Lake City, Utah. PacifiCorp's corporate headquarters are in Portland, but there are several executives and departments located in Salt Lake City. In addition to the corporate headquarters, PacifiCorp owns and leases approximately 1 million square feet of field office and warehouse space in various other locations in Utah, Oregon, Wyoming, Washington, Idaho and California. The field location square footage does not include offices located at PacifiCorp's electricity 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. Refer to Note 13 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for information regarding legal proceedings, including the USA Power litigation.

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 2013, PacifiCorp declared and paid a dividend of $150 million to PPW Holdings.

In 2012 and 2011, PacifiCorp declared and paid dividends of $200 million and $550 million to PPW Holdings, respectively.

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 the information in 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,				
	2012	2011	2010	2009	2008
Consolidated Statement of Operations Data:					
Operating revenue	$ 4,882	$ 4,586	$ 4,432	$ 4,457	$ 4,498
Operating income	1,021	1,084	1,036	1,060	954
Net income attributable to PacifiCorp	537	555	566	542	458

	As of December 31,				
	2012	2011	2010	2009	2008
Consolidated Balance Sheet Data:					
Total assets	$ 21,728	$ 21,106	$ 20,146	$ 18,966	$ 17,167
Short-term debt	—	688	36	—	85
Current portion of long-term debt and capital lease obligations	267	19	588	16	144
Long-term debt and capital lease obligations, excluding current portion	6,594	6,194	5,813	6,400	5,424
Total PacifiCorp shareholders' equity	7,644	7,312	7,311	6,648	5,987

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 for the year ended December 31, 2012 was $537 million, a decrease of $18 million, or 3%, as compared to 2011. Net income decreased largely due to after-tax charges totaling $102 million in 2012 related to the USA Power litigation and certain fire and other damage claims. Excluding these charges, net income increased $84 million compared to 2011 primarily due to higher retail prices approved by regulators across most of PacifiCorp's jurisdictions and higher retail customer load, partially offset by higher fuel and purchased electricity costs, the settlement of the Utah general rate case in 2011, higher depreciation expense due to higher plant in service and lower wholesale electricity revenue. Energy generated increased 3% for 2012 compared to 2011 due to higher coal- and natural gas-fueled generation from improved availability, as well as improved spark spreads at PacifiCorp's natural gas-fueled generating facilities, partially offset by lower hydroelectric and wind-powered generation.

Net income for the year ended December 31, 2011 was $555 million, a decrease of $11 million, or 2%, as compared to 2010. Net income decreased primarily due to lower wholesale electricity revenue, higher volumes of purchased electricity, higher coal prices, higher depreciation and property tax expenses due to higher plant in service, lower allowance for funds used during construction 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 impacts of the 2011 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 at PacifiCorp's natural gas- and coal-fueled generating facilities.

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

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011

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

	2012	2011	Favorable/(Unfavorable) Change	% Change
Gross margin (in millions):				
Operating revenue	$ 4,882	$ 4,586	$ 296	6 %
Energy costs	1,818	1,636	(182)	(11)
Gross margin	$ 3,064	$ 2,950	$ 114	4 %
Volumes of electricity sold (in GWh):				
Residential	15,968	16,046	(78)	— %
Commercial	16,829	16,489	340	2
Industrial and irrigation	21,317	21,229	88	—
Other	435	543	(108)	(20)
Total retail electricity sales	54,549	54,307	242	—
Wholesale electricity sales	11,870	10,767	1,103	10
Total electricity sales	66,419	65,074	1,345	2 %
Retail electricity sales:				
Average retail customers (in thousands)	1,754	1,742	12	1 %
Average revenue per MWh	$ 78.93	$ 74.79	$ 4.14	6 %
Wholesale electricity revenue:				
Average revenue per MWh	$ 27.59	$ 32.49	$ (4.90)	(15)%
Volumes of electricity generated (in GWh):				
Coal-fueled generation	42,457	40,789	1,668	4 %
Natural gas-fueled generation	7,233	6,320	913	14
Hydroelectric generation (1)	4,262	4,680	(418)	(9)
Wind and other(1)	3,319	3,652	(333)	(9)
Total PacifiCorp generated volumes	57,271	55,441	1,830	3 %
Volumes of electricity purchased (in GWh):				
Purchased electricity	13,777	13,963	186	1 %
Purchased electricity:				
Average cost per MWh	$ 41.92	$ 38.41	$ (3.51)	(9)%

(1) 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 RECs or other environmental commodities.

Gross margin increased $114 million, or 4%, for 2012 compared to 2011 primarily due to:

- $222 million of increases from higher retail prices approved by regulators net of a $17 million one-time credit to be provided to Oregon customers in 2013 as a result of the 2012 Oregon general rate case outcome pertaining to PacifiCorp's investments in certain emissions control equipment at its coal-fueled generating facilities;

- $29 million of increases from lower net deferrals and higher sales of renewable energy credits excluding the impacts of the Utah general rate case settlement in 2011; and

- $22 million of higher retail customer load due to the impacts of hot weather in Utah on residential and commercial customers, higher irrigation load in Idaho and Utah and higher industrial load in Utah, partially offset by lower industrial load in Wyoming and Oregon as certain large customers elected to self-generate and lower residential load in Oregon as a result of unfavorable weather.

The increase in gross margin was partially offset by:

- $89 million of higher fuel and purchased electricity costs due to increased thermal generation, higher cost of purchased electricity and higher unit coal costs, partially offset by lower unit natural gas costs;

- $30 million related to the Utah general rate case settlement in 2011, which provided for the recovery of $60 million of previously incurred 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 and for a $30 million credit to customers for the refund of renewable energy credit sales that substantially occurred prior to 2011 and that was credited to Utah customers' bills over the period from September 2011 through May 2012;

- $22 million of lower wholesale electricity revenue as a result of lower average market prices, partially offset by increased volumes resulting from improved thermal generation availability; and

- $19 million of lower net deferrals of incurred net power costs in accordance with established adjustment mechanisms aside from the 2011 Utah general rate case settlement.

Operations and maintenance increased $139 million, or 13%, for 2012 compared to 2011 primarily due to $165 million of charges in 2012 related to the USA Power litigation and certain fire and other damage claims. The USA Power litigation is described in Note 13 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Depreciation and amortization increased $29 million, or 5%, for 2012 compared to 2011 primarily due to higher plant in service.

Taxes, other than income taxes increased $9 million, or 6%, for 2012 compared to 2011 primarily due to increased property taxes from higher plant in service.

Interest expense decreased $12 million, or 3%, for 2012 compared to 2011 primarily due to lower average interest rates, partially offset by higher average debt outstanding.

Allowances for borrowed and equity funds increased $15 million, or 21%, for 2012 compared to 2011 primarily due to higher qualified construction work-in-progress balances.

Income tax expense decreased $16 million, or 8%, for 2012 compared to 2011 and the effective tax rate was 27% and 28% for 2012 and 2011, respectively. The decrease in income tax expense was primarily due to lower pre-tax income and the effects of ratemaking, partially offset by lower production tax credits associated with PacifiCorp's wind-powered generating facilities.

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:

	2011	2010	Favorable/(Unfavorable) 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 revenue:				
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 [1]	4,680	3,744	936	25
Wind and other [1]	3,652	2,862	790	28
Total PacifiCorp generated volumes	55,441	57,634	(2,193)	(4)%
Volumes of electricity purchased (in GWh):				
Purchased electricity	13,963	11,329	(2,634)	(23)%
Purchased electricity:				
Average cost per MWh	$ 38.41	$ 38.50	$ 0.09	— %

(1) 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 RECs or other environmental commodities.

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 from higher net deferrals of incurred net power costs in accordance with established adjustment mechanisms, including $60 million related to the 2011 Utah general rate case settlement; 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 costs and lower volumes of wholesale electricity revenue, 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 related to the 2011 Utah general rate case settlement; and
- $11 million of decreases due to the elimination of certain regulatory liabilities in 2010 resulting from the 2010 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 the 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 from higher plant in service.

Interest expense increased $5 million, or 1%, for 2011 compared to 2010 primarily due to interest accruals associated with the 2011 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.

Liquidity and Capital Resources

As of December 31, 2012, PacifiCorp's total net liquidity was $708 million and the components were as follows (in millions):

Cash and cash equivalents	$	80
Available revolving credit facilities[1]		1,230
Less:		
Short-term debt		—
Letters of credit supporting tax-exempt bond obligations and collateral requirements of commodity contracts		(602)
Net revolving credit facilities available		628
Total net liquidity	$	708
Unsecured revolving credit facilities:		
Maturity dates		2013, 2017
Largest single bank commitment as a % of total[2]		14%

(1) For further discussion regarding PacifiCorp's credit facilities, refer to Note 6 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.

Operating Activities

Net cash flows from operating activities for the years ended December 31, 2012 and 2011 were $1.627 billion and $1.636 billion, respectively. The $9 million decrease was primarily due to higher income tax receipts in 2011 mainly related to 2010 bonus depreciation and higher energy costs in 2012, partially offset by higher retail prices approved by regulators, benefits from changes in collateral posted for derivative contracts and lower contributions to PacifiCorp's pension and other postretirement benefit plans in 2012.

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.

In January 2013, the President signed the American Taxpayer Relief Act of 2012 into law, extending the 50% bonus depreciation for qualifying property purchased and placed in service before January 1, 2014 and before January 1, 2015 for certain longer-lived and transportation assets. As a result of the new law, PacifiCorp's cash flows from operations are expected to benefit in 2013 and 2014 due to bonus depreciation on qualifying assets placed in service.

Investing Activities

Net cash flows from investing activities for the years ended December 31, 2012 and 2011 were $(1.342) billion and $(1.529) billion, respectively. Capital expenditures decreased $160 million primarily due to lower expenditures for emissions control equipment and distribution, generation, mining and other infrastructure projects, partially offset by higher expenditures for transmission system investments and new generating facilities.

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 emissions control equipment and transmission system investments, partially offset by higher expenditures for new generating facilities.

Capital Expenditures

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

2012

- Transmission system investments totaling $311 million, including construction 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-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 the second quarter of 2013.

- The development and construction of Lake Side 2 totaling $232 million, which is expected to be placed in service in 2014.

- Emissions control equipment on existing generating facilities totaling $75 million for installation or upgrade of sulfur dioxide scrubbers, low nitrogen oxide burners and particulate matter control systems.

- Distribution, generation, mining and other infrastructure needed to serve existing and expected demand totaling $728 million.

2011

- Transmission system investments totaling $216 million, including permitting and right-of-way costs for the Mona-Oquirrh transmission project.

- 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 Lake Side 2 totaling $180 million.

- 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.

Financing Activities

Short-term Debt and Revolving Credit Facilities

Regulatory authorities limit PacifiCorp to $1.5 billion of short-term debt. PacifiCorp had no short-term debt outstanding as of December 31, 2012 as compared to $688 million of short-term debt outstanding as of December 31, 2011 at a weighted-average interest rate of 0.51%. PacifiCorp had no outstanding borrowings under its unsecured revolving credit facilities as of December 31, 2012 or 2011.

For further discussion, refer to Note 6 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. In March 2012, PacifiCorp issued an additional $100 million of its 2.95% First Mortgage Bonds due February 1, 2022. The net proceeds were used to redeem $84 million of tax-exempt bond obligations prior to scheduled maturity with a weighted average interest rate of 5.72%, to repay short-term debt and for general corporate purposes.

PacifiCorp currently has regulatory authority from the OPUC and the IPUC to issue an additional $850 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, to repay short-term debt and for general corporate purposes.

PacifiCorp made scheduled repayments on long-term debt totaling $17 million and $587 million during the years ended December 31, 2012 and 2011, respectively.

As of December 31, 2012, 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, 2012 and expire periodically through November 2013.

PacifiCorp's Mortgage and Deed of Trust creates a lien on most of PacifiCorp's electric utility property, allowing the issuance of bonds based on a percentage of utility property additions, bond credits arising from retirement of previously outstanding bonds 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, 2012, PacifiCorp estimated it would be able to issue up to $7.8 billion of new first mortgage bonds under the most restrictive issuance test in the mortgage. Any issuances are subject to market conditions and amounts may be further limited by regulatory authorizations or commitments or by covenants and tests contained in other financing agreements. PacifiCorp also has the ability to release property from the lien of the mortgage on the basis of property additions, bond credits or deposits of cash.

PacifiCorp may from time to time seek to acquire its outstanding 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 2013, PacifiCorp declared and paid a dividend of $150 million to PPW Holdings.

In 2012 and 2011, PacifiCorp declared and paid dividends of $200 million and $550 million to PPW Holdings, 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 or prospective 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, 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; impacts to customers' rates; 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; commodity prices; 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 $3.4 billion on capital projects over the next three years, excluding non-cash equity AFUDC and other non-cash items. These capital projects include new generating resources; transmission investments; installation of emissions control equipment on existing generating facilities; and distribution investments in new connections, lines and substations.

Forecasted capital expenditures, excluding non-cash equity AFUDC and other non-cash items, for the years ended December 31 are as follows (in millions):

	2013	2014	2015
Forecasted capital expenditures:			
Generation development	$ 225	$ 141	$ 36
Transmission system investment	280	330	289
Environmental	141	173	130
Other	516	493	660
Total	$ 1,162	$ 1,137	$ 1,115

The capital expenditure estimate for generation development projects includes the construction of Lake Side 2 that is expected to be placed in service in 2014 and costs to convert Naughton Unit No. 3 to a natural gas-fueled generating unit.

The capital expenditure estimate for transmission system investment includes projects associated with the Energy Gateway Transmission Expansion Program totaling $696 million, including the following estimated costs:

- $76 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-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 $383 million, including AFUDC, and is expected to be placed in service in 2013.

- $309 million for the 170-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-Red Butte project is estimated to cost $383 million, including AFUDC, and is expected to be placed in service in 2015.

- $311 million for other segments associated with the Energy Gateway Transmission Expansion Program that are expected to be placed in service over the next several years, 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, 2012 (in millions):

	Payments Due By Periods				
	2013	2014-2015	2016-2017	2018 and After	Total
Long-term debt, including interest:					
Fixed-rate obligations	$ 566	$ 873	$ 650	$ 10,252	$ 12,341
Variable-rate obligations(1)	43	160	105	354	662
Capital leases, including interest	12	15	18	70	115
Operating leases and easements	6	9	5	44	64
Asset retirement obligations	13	25	34	251	323
Power purchase agreements(2):					
Electricity commodity contracts	92	65	58	164	379
Electricity capacity contracts	79	144	89	247	559
Electricity mixed contracts	7	16	16	39	78
Transmission	105	172	129	671	1,077
Fuel purchase agreements(2):					
Natural gas supply and transportation	59	79	63	380	581
Coal supply and transportation	607	1,092	737	1,598	4,034
Other purchase obligations	439	217	43	131	830
Other long-term liabilities(3)	74	13	12	55	154
Total contractual cash obligations	$ 2,102	$ 2,880	$ 1,959	$ 14,256	$ 21,197

(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, 2012 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 2013 as disclosed in Note 9 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 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%. In July 2012, PacifiCorp filed rebuttal testimony that reduced the requested increase to $156 million, or an average price increase of 9%. In September 2012, the UPSC approved a multi-year settlement that provides for an annual increase of $100 million, or an average price increase of 6%, effective October 2012, to be followed by an additional annual increase of $54 million, or an average price increase of 3%, effective September 2013. As part of the general rate case settlement, PacifiCorp indicated that it anticipates retiring the 172-MW Carbon coal-fueled generating facility ("Carbon Facility") in early 2015. Refer to "Environmental Laws and Regulations" for a further discussion regarding the Carbon Facility. The settlement authorizes PacifiCorp to recover the remaining depreciation expense and decommissioning costs for the early retirement of the Carbon Facility through 2020, which is the end of the depreciation life previously used for setting rates in Utah. In addition, PacifiCorp agreed not to file another general rate case in Utah prior to January 2014 with the new rates to become effective no earlier than September 2014.

In March 2012, PacifiCorp filed its first annual EBA with the UPSC requesting: (a) $9 million for recovery of 70% of the net power costs in excess of amounts included in base rates for the period October 1, 2011 through December 31, 2011 and (b) collection of $20 million of excess net power costs representing the first annual installment of the $60 million of excess net power costs approved for recovery in the September 2011 general rate case settlement. Collection of the $20 million installment began in June 2012. In February 2013, the UPSC approved a multi-party stipulation reducing the recovery of the net power costs in excess of amounts included in base rates for the period October 1, 2011 through December 31, 2011 to $8 million. Collection of the $8 million began March 1, 2013 over a two-year period.

In March 2012, PacifiCorp filed with the UPSC to return $4 million to customers through the REC balancing account. The new rates were effective June 2012 on an interim basis. In November 2012, the UPSC approved the interim rates as final.

Oregon

In February 2012, PacifiCorp made its initial filing for the annual TAM with the OPUC for an annual increase of $10 million, or an average price increase of 1%, to recover the anticipated net power costs forecasted for calendar year 2013. In July 2012, PacifiCorp filed updated net power costs reducing the requested increase to $3 million, or an average price increase of less than 1%. In November 2012, PacifiCorp filed final updated net power costs resulting in an overall increase of $2 million, or an average price increase of less than 1%. In December 2012, the OPUC approved the new rates, which became effective January 2013.

In March 2012, PacifiCorp filed a general rate case with the OPUC requesting an annual increase of $41 million, or an average price increase of 3%. In July 2012, a multiparty partial stipulation was filed with the OPUC resolving most components of the general rate case, including PacifiCorp's requests to include in rates the accelerated depreciation and decommissioning costs for the early retirement of the Carbon Facility. The stipulation provides for an annual increase of $24 million, or an average price increase of 2%. The issues that were not settled in the stipulation included the prudence of PacifiCorp's investments in emissions control equipment at its coal-fueled generating facilities, PacifiCorp's request for a PCAM and PacifiCorp's proposal to add the Mona-Oquirrh transmission line to its rate base through a separate tariff rider when the line goes into service in 2013. The OPUC issued its final order in December 2012, which approved the stipulation effective January 2013. The order also approved the capital and operating expenses associated with PacifiCorp's emissions control investments at certain coal-fueled generation facilities but ordered a one-time credit of $17 million, representing 10% of Oregon-allocated emissions control investments included in the general rate case, to be credited to customers in 2013 through a separate tariff rider. The order also approved the separate tariff rider for the Mona-Oquirrh transmission line and the PCAM with modifications. The PCAM will be effective beginning with calendar year 2013. For additional information regarding the PCAM, refer to "General Regulation" in Item 1 of this Form 10-K.

On March 1, 2013, PacifiCorp filed a general rate case with the OPUC requesting an annual increase of $56 million, or an average price increase of 5%. If the separate tariff rider for the Mona-Oquirrh transmission line that was approved in the last general rate case becomes effective when the asset is placed into service, PacifiCorp's requested annual increase will be reduced to $45 million, or an average price increase of 4%. Also included as part of PacifiCorp's general rate case filing is a request for a prudence determination and a separate tariff rider for the Lake Side 2 natural gas-fueled generating facility. If approved by the OPUC, the separate tariff rider will become effective after the project is complete, resulting in an additional increase of $23 million or 2%.

On March 1, 2013, PacifiCorp made its initial filing for the annual TAM with the OPUC for an annual decrease of $1 million in anticipation of net power costs forecasted for calendar year 2014.

Wyoming

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%, for which the outcome is described below.

In March 2012, PacifiCorp made its first annual Wyoming ECAM filing with the WPSC. The filing requested recovery of $29 million, or an average price increase of 5%, for deferred net power costs for the period December 1, 2010 to December 31, 2011. The new rates were effective May 2012 on an interim basis and were revised in July 2012 in anticipation of the general rate case stipulation described below.

In July 2012, the WPSC approved a stipulation that consolidated and resolved the December 2011 general rate case and the March 2012 ECAM filing. The stipulation resulted in a $50 million general rate increase that will be effective in two stages. The first increase of $32 million, or an average price increase of 5%, was effective in October 2012 and the second increase of $18 million, or an average price increase of 3%, will be effective in October 2013. The stipulation also resulted in a reduction of the ECAM surcharge rate increase from $29 million to $27 million and the increase will be collected over three years. The stipulation authorizes PacifiCorp to recover the remaining depreciation expense and decommissioning costs for the early retirement of the Carbon Facility through 2020, which is the end of the depreciation life previously used for setting rates in Wyoming. In addition, PacifiCorp agreed not to file another general rate case in Wyoming prior to March 2014 with the new rates to become effective no earlier than January 2015.

In March 2012, PacifiCorp filed its first annual Wyoming RRA application with the WPSC. The RRA tracks the difference between PacifiCorp's actual revenues from the sale of RECs and sulfur dioxide allowances and the amounts credited to customers in current rates. The filing requested a $1 million reduction in the surcredit to $15 million. The new surcredit became effective in May 2012 on an interim basis. In September 2012, the WPSC approved the RRA on a permanent basis with no change to the previously approved interim rate.

In September 2011, PacifiCorp filed with the WPSC an application for a certificate of public convenience and necessity ("CPCN") for pollution control facilities at Naughton Unit No. 3 in Wyoming. In April 2012, PacifiCorp filed testimony modifying its original CPCN application to reflect its current plan to convert the Naughton Unit No. 3 to a natural gas-fueled unit as a result of PacifiCorp's current estimation that conversion is the least cost alternative for meeting air quality and visibility requirements and is in the best interest of customers. In May 2012, PacifiCorp filed a motion to withdraw the CPCN application, which was approved by the WPSC.

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 an 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 in the 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 proposed that PacifiCorp credit to customers the amount of REC sales revenues in excess of the amount included in base rates since January 1, 2009. Oral arguments were held before the WUTC in January 2012. In August 2012, the WUTC issued an order requiring PacifiCorp to credit to its customers all proceeds from the sale of RECs attributable to Washington that were booked on or after January 1, 2009, less any amounts already credited to customers. In September 2012, PacifiCorp filed a petition for reconsideration and a petition requesting a stay of the effectiveness of the order, which was denied in a November 2012 order by the WUTC. In December 2012, PacifiCorp submitted a compliance filing with the WUTC presenting Washington-allocated actual REC sales revenues of $17 million from January 2009 through March 2011. Also in December 2012, PacifiCorp filed for judicial review of the WUTC's August and November 2012 orders with the Thurston County, Washington, Superior Court. In February 2013, PacifiCorp, WUTC staff and intervening parties submitted a joint filing with the WUTC proposing a tracking mechanism for REC sales revenues.

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%. In March 2012, the WUTC approved the settlement agreement with an effective date of June 2012.

In January 2013, PacifiCorp filed a general rate case with the WUTC requesting an annual increase of $43 million, or an average price increase of 14%. The requested increase includes the impacts associated with investments in PacifiCorp's facilities since the last general rate case filing, as well as projected increases in net power costs. In February 2013, the WUTC issued a prehearing conference order, which among other things, established a procedural schedule for PacifiCorp's general rate case filing.

Idaho

In February 2012, PacifiCorp filed its annual ECAM application with the IPUC requesting recovery of $18 million in deferred net power costs. A final order approving the agreement reached by the parties to the case was approved by the IPUC in July 2012 authorizing recovery of the $18 million in deferred net power costs with a portion of the $18 million being recovered over a three-year period. The new ECAM rates were made effective April 2012.

In February 2013, PacifiCorp filed its annual ECAM application with the IPUC requesting recovery of $16 million of deferred net power costs, a portion of which will be collected over a three-year period. If approved, the new ECAM rates will be effective April 2013.

California

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. In March 2012, the CPUC approved the stipulation and the new rates became effective March 2012.

In July 2012, PacifiCorp filed a PTAM for major capital additions with the CPUC requesting an increase of $1 million, or an average price increase of 1%. The CPUC approved the new rates, which became effective August 2012.

In October 2012, PacifiCorp filed its annual PTAM attrition adjustment with the CPUC requesting an increase of $1 million, or an average price increase of 1%. In December 2012, the CPUC approved the new rates, which became effective January 2013.

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 to 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 using the new rates commenced in early 2012. The FERC established settlement proceedings to encourage the parties to reach agreement on final rates. In February 2013, agreement with the parties was reached and PacifiCorp filed a settlement agreement with the FERC resolving all issues in the transmission rate case. The settlement agreement is subject to FERC approval and includes modifications to the formula used to determine transmission rates. The FERC approved interim rates for real power loss factors and certain ancillary services to be effective March 1, 2013 and for a new reactive power service rate to be effective May 1, 2013. The transmission rates will continue to be updated every June according to the formula rate process.

Depreciation Rate Study

In January 2013, PacifiCorp filed applications for depreciation rate changes with the UPSC, the OPUC, the WPSC, the WUTC and the IPUC based on PacifiCorp's most recent depreciation study. The proposed depreciation rate changes would result in an increase in annual depreciation expense on a state-allocated basis of $71 million, $31 million, $27 million, $1 million and $9 million in Utah, Oregon, Wyoming, Washington and Idaho, respectively, including the impacts of the early retirement of the Carbon Facility. The depreciation study will be evaluated by the state commissions during 2013 and is subject to their review and approval. PacifiCorp requested that the new depreciation rates become effective January 1, 2014. Associated changes in retail rates will be addressed through the general rate case process and were requested as a component of the general rate cases filed with the WUTC and the OPUC in January 2013 and March 2013, respectively. As a result of PacifiCorp's most recently settled Utah and Wyoming general rate cases, the UPSC and the WPSC authorized PacifiCorp to defer the difference between the new depreciation rates and those currently reflected in base rates until the new depreciation rates can be reflected in the next general rate increases. PacifiCorp also has authorization to defer the increase in depreciation expense associated with the early retirement of the Carbon Facility in Utah, Wyoming and Idaho to facilitate recovery through 2020, which is the end of the depreciation life previously used for setting rates in Utah, Wyoming and Idaho. As a result of the deferrals related to Carbon, the proposed adjusted annual increase in depreciation expense on a state-allocated basis in Utah, Wyoming and Idaho would be $38 million, $15 million and $5 million, respectively, subject to state commission approvals.

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 "Liquidity and Capital Resources" for discussion of PacifiCorp's forecasted environmental-related capital expenditures.

Clean Air Act Regulations

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, which are a collection of regulations, programs and policies to be followed. SIPs 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. While this designation has the potential to impact PacifiCorp's Lake Side and Gadsby generating facilities, the Utah SIP as submitted to the EPA did not impose significant new requirements on PacifiCorp's impacted generating facilities, nor did the EPA's comments on the Utah SIP identify requirements for PacifiCorp's generating facilities that would have a material impact on PacifiCorp's consolidated financial results.

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. Final designations were released in April 2012, designating portions of Lincoln and Sweetwater Counties and Sublette County to be in marginal nonattainment. While PacifiCorp's Jim Bridger plant is located in Sweetwater County, it is not in the portion of the designated nonattainment area and is not expected to be impacted by the designation.

In January 2010, the EPA finalized a one-hour air quality standard for nitrogen dioxide at 0.10 part per million. In February 2012, the EPA published final designations 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 were due by June 2012; however, due to the lack of sufficient information to make the designations, the EPA extended the deadline for area designations to June 2013.

In June 2012, the EPA released a proposal to strengthen the fine particulate matter national ambient air quality standards, reducing the standard from 15 micrograms per cubic meter to a range of 12 to 13 micrograms per cubic meter while taking comment on a standard of 11 micrograms per cubic meter. The EPA also proposed a new, separate fine particulate matter standard of either 28 or 30 deciviews or measure of haze, aimed at improving visibility. The new standard was released in December 2012, setting 12 micrograms per cubic meter as the annual standard and retaining the 24-hour standard at 35 micrograms per cubic meter. The EPA did not set a separate secondary visibility standard, choosing to rely on the existing secondary 24-hour standard to protect against visibility impairment. The EPA anticipates making initial attainment designations by December 2014 that are likely to become effective in early 2015. States would have until 2020 to meet the revised annual standard. Until the attainment designations are made, PacifiCorp cannot determine the potential impacts of the standards; however, with the release of the final standards, the EPA indicated its projections show 99% of all counties in the United States with monitors would meet the revised standard. As a result, PacifiCorp does not anticipate that any impacts of the revised standard will be significant.

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 published in the Federal Register in February 2012, with an effective date of April 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 by April 16, 2015. Individual sources may be granted up to one additional year, at the discretion of the Title V permitting authority, to complete installation of controls or for transmission system reliability reasons. 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. PacifiCorp currently anticipates that retiring the Carbon Facility in early 2015 will be the least-cost alternative to comply with the MATS and other environmental regulations. PacifiCorp continues to assess compliance alternatives and potential transmission system impacts that could otherwise impact PacifiCorp's ultimate decision with respect to the Carbon Facility, including timing of retirement and decommissioning. Incremental costs to install and maintain emissions control equipment at PacifiCorp's coal-fueled generating facilities and any requirement to shut down what have traditionally been low cost coal-fueled generating facilities will likely increase the cost of providing service to customers. In addition, numerous lawsuits are pending against the MATS in the D.C. Circuit, which may have an impact on PacifiCorp's compliance obligations and the timing of those obligations.

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 Arizona, Utah and Wyoming are subject to the Clean Air Visibility Rules. In accordance with the federal requirements, states are required to submit SIPs that address emissions from sources subject to best available retrofit technology requirements and demonstrate progress towards achieving natural visibility requirements in Class I areas by 2064.

The state of Utah issued a regional haze SIP requiring the installation of sulfur dioxide, nitrogen oxides and particulate matter controls on Hunter Units 1 and 2, and Huntington Units 1 and 2. In December 2012, the EPA approved the sulfur dioxide portion of the Utah regional haze SIP and disapproved the nitrogen oxides and particulate matter portions. Certain groups have appealed the EPA's approval of the sulfur dioxide portion. The date for appealing the disapproval of the nitrogen oxides and particulate matter portions is March 25, 2013. In addition, and separate from the EPA's approval process and related litigation, the Utah Division of Air Quality is undertaking an additional best available retrofit technology analysis for each of Hunter Units 1 and 2, and Huntington Units 1 and 2, which will be provided to the EPA as a supplement to the existing Utah SIP. It is unknown whether and how this supplemental analysis will impact the EPA's approval and disapproval of the existing SIP.

In Wyoming, the state issued two regional haze SIPs requiring the installation of sulfur dioxide, nitrogen oxides and particulate matter controls on certain PacifiCorp coal-fueled generating facilities in Wyoming. The EPA approved the sulfur dioxide SIP in December 2012, but initially proposed to disapprove portions of the nitrogen oxides and particulate matter SIP and instead issue a FIP. The EPA proposed to approve the installation of selective catalytic reduction equipment and a baghouse at Naughton Unit 3 by December 31, 2014; to approve the installation of selective catalytic reduction equipment at Jim Bridger Unit 3 by December 31, 2015; and to approve the installation of selective catalytic reduction equipment at Jim Bridger Unit 4 by December 31, 2016. The EPA proposed to disapprove the nitrogen oxides and particulate matter SIP for Jim Bridger Units 1 and 2 and instead accelerate the installation of selective catalytic reduction equipment to 2017 from 2021 and 2022, but agreed to accept comment on maintaining the original schedule as the state proposed. In addition, the EPA proposed to reject the SIP for the Wyodak facility and Dave Johnston Unit 3 and require the installation of selective non-catalytic reduction equipment within five years, as well as require the installation of low-nitrogen oxides burners and overfire air systems at Dave Johnston Units 1 and 2. Since the EPA's initial proposal, the EPA has withdrawn its proposed actions on the SIP and its proposed FIP and has indicated its intent to re-propose action of the Wyoming nitrogen oxides and particulate matter SIP by March 2013, and take final action by September 2013. In the meantime, certain groups have appealed the EPA's approval of the sulfur dioxide SIP.

In Arizona, the state issued a regional haze SIP requiring, among other things, the installation of sulfur dioxide, nitrogen oxides and particulate matter controls on Cholla Unit 4. The EPA approved in part, and disapproved in part, the Arizona SIP and issued a FIP for the disapproved portions. PacifiCorp filed an appeal in the United States Court of Appeals for the Ninth Circuit ("Ninth Circuit") regarding the FIP as it relates to Cholla Unit 4, and the Arizona Department of Environmental Quality and other affected Arizona utilities filed separate appeals of the FIP as it relates to their interests. The Ninth Circuit has not made any decisions in regard to these appeals.

Other cases are pending before the United States Court of Appeals for the Tenth Circuit with regard to similar appeals of FIPs issued by the EPA in New Mexico and Oklahoma.

Until the EPA takes final action in each state and decisions have been made on each appeal, PacifiCorp cannot fully determine the impacts of the Regional Haze regulation on its generating facilities.

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

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. Regulation of GHG emissions under various provisions of the Clean Air Act has continued since the EPA's December 2009 findings that GHG emissions threaten public health and welfare.

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 in the D.C. Circuit. In June 2012, the D.C. Circuit dismissed the challenges to the rules and upheld the EPA's actions. Petitions for rehearing by the full D.C. Circuit were filed, which were denied in December 2012.

In April 2012, the EPA proposed New Source Performance Standards for GHG at new fossil-fueled generating facilities at an emissions rate of 1,000 pounds per MWh, which are expected to be finalized in the first half of 2013. The EPA is also under a consent decree to establish GHG emissions performance standards for existing and modified sources.

International discussions regarding climate change continue to be held periodically with the expiration of the Kyoto Protocol in December 2012. During the December 2012 18th Conference of the Parties in Doha, Qatar, the parties to the Kyoto Protocol agreed to a Kyoto Protocol 2 that will involve more than 25 nations (mainly the European Union and Australia), comprising about 15% of global GHG emissions, to run from 2013 to 2020.

While the debate continues at the federal and international level over the direction of climate change policy, several states have continued to implement 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.

In September 2009, the EPA issued its final rule regarding mandatory GHG Reporting 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.

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 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, 2012, PacifiCorp owned 1,031 MW of operating wind-powered generating capacity at a total cost of $2.1 billion. PacifiCorp has power purchase agreements with 869 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, nitrogen oxides and particulate matter.

New federal, regional, state and international accords, legislation, regulation, or judicial proceedings 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.

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. 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. PacifiCorp's management believes compliance with the GHG limits under these permits will not result in a material adverse impact on its operations. 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. In April 2012, the EPA proposed new source performance standards for new fossil-fueled generating facilities that would limit emissions of carbon dioxide to 1,000 pounds per MWh. The proposal exempts simple cycle combustion turbines from meeting the GHG standards. The public comment period closed in June 2012 and a final rule is expected by April 2013. Any new fossil-fueled generating facilities constructed by PacifiCorp will be required to meet the final GHG new source performance standards, which, if finalized as proposed, will preclude the construction of any coal-fueled generating facilities that do not have carbon capture and sequestration. Additionally, as proposed, it may be difficult even for combined cycle combustion turbines to meet the carbon dioxide emission standard under certain operating scenarios such as simple cycle or low-load operations on a sustained basis. The EPA indicated in the proposal that it does not have sufficient information to establish GHG new source performance standards for modified or reconstructed units and has not established a schedule for when these units, or other existing sources, will be regulated. However, the EPA is under a consent decree obligation to establish such standards. Until any standards for existing, modified or reconstructed units are proposed and finalized, the impact on PacifiCorp's existing facilities 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 and provinces having left the effort.

- Under the authority of California's Global Warming Solutions Act signed into law in 2006, 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. The program purports to impose compliance obligations on entities, including PacifiCorp, that deliver wholesale energy to points that are outside of California, irrespective of retail service obligations. These obligations and other impacts to wholesale energy market structures may, if implemented as written, increase costs to PacifiCorp. 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. The first auction of GHG allowances was held in California in November 2012.

- Over the past several years, the states of California, Washington and Oregon have adopted GHG emissions performance standards for base load electricity 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. In addition, Washington is undertaking a rulemaking to reduce the emissions performance standard for GHG emissions, which is currently proposed at 970 pounds of carbon dioxide per MWh. If finalized as proposed, the Washington standard will become effective in March 2013.

- 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.

GHG Litigation

PacifiCorp closely monitors ongoing environmental litigation. Many of the pending cases described below relate to lawsuits against the industry that attempt to link GHG emissions to public or private harm. PacifiCorp believes the cases are without merit, despite decisions where United States Courts of Appeals reversed district court rulings dismissing the cases in 2009. The lower courts initially refrained from adjudicating the cases under the "political question" doctrine, because of their inherently political nature. Nevertheless, an adverse ruling in any of these cases would likely result in increased regulation and costs for GHG emitters, including PacifiCorp's generating facilities.

In September 2009, the United States Court of Appeals for the Second Circuit ("Second Circuit") issued its opinion in the case of *Connecticut v. American Electric Power, et al*, which remanded to the lower court a nuisance action by eight states and the City of New York against five large utility emitters of carbon dioxide. The United States District Court for the Southern District of New York ("Southern District of New York") dismissed the case in 2005, holding that the claims that GHG emissions from the defendants' coal-fueled generating facilities were causing harmful climate change and should be enjoined as a public nuisance under federal common law presented a "political question" that the court lacked jurisdiction to decide. The Second Circuit rejected this conclusion and stated the Southern District of New York was not precluded from determining the case on its merits. In December 2010, the United States Supreme Court agreed to hear the case on appeal from the Second Circuit and issued its decision in June 2011 dismissing the federal common law claim of nuisance and holding that the Clean Air Act provides a means to seek limits on emissions of carbon dioxide on power plants.

In 2007, the United States District Court for the Southern District of Mississippi ("Southern District of Mississippi") dismissed the case of *Ned Comer, et al. v. Murphy Oil USA, et al.* ("Comer I"). Plaintiffs brought the putative class action lawsuit based on claims that the defendants' GHG emissions contributed to global warming that resulted in a rise in sea level and added to the ferocity of Hurricane Katrina, which caused damage to the plaintiffs' property. Plaintiffs petitioned for a rehearing before the full court of the United States Court of Appeals for the Fifth Circuit ("Fifth Circuit") in March 2010, but in May 2010, the Fifth Circuit dismissed the appeal for failure to have a quorum. The dismissal resulted in the Southern District of Mississippi's decision, holding that property owners did not have standing to sue for climate change and that climate change was a political question for the United States Congress, standing as good law. However, in May 2011, the Comer case was refiled ("Comer II") in the Southern District of Mississippi. In response to the defendants' motions to dismiss in Comer II, the Southern District of Mississippi, in March 2012, granted the motions, dismissing the suit with prejudice. Plaintiffs filed an appeal with the Fifth Circuit in April 2012. Briefs have been filed in the appeal but the court has not yet scheduled oral argument. PacifiCorp was not a party in Comer I and is not a party in Comer II.

In October 2009, the United States District Court for the Northern District of California ("Northern District of California") granted the defendants' motions to dismiss in the case of *Native Village of Kivalina v. ExxonMobil Corporation, et al.* The plaintiffs filed their complaint in February 2008, asserting claims against 24 defendants, including electric generating companies, oil companies and a coal company, for public nuisance under state and federal common law based on the defendants' GHG emissions. The Northern District of California dismissed all of the plaintiffs' federal claims, holding that the court lacked subject matter jurisdiction to hear the claims under the political question doctrine, and that the plaintiffs lacked standing to bring their claims. The Northern District of California declined to hear the state law claims and the case was dismissed without prejudice to their future presentation in an appropriate state court. In November 2009, the plaintiffs appealed the case to the Ninth Circuit. In September 2012, the Ninth Circuit issued its opinion affirming the Northern District of California's dismissal of the plaintiffs' complaint. The Ninth Circuit held that the Clean Air Act displaced the plaintiffs' federal common law claims. In October 2012, the plaintiffs filed a petition for a full rehearing by the Ninth Circuit, which was denied by the Ninth Circuit in November 2012. It is possible the plaintiffs will seek review by the United States Supreme Court.

Renewable Portfolio Standards

Each state's RPS described below could significantly impact PacifiCorp's consolidated financial results. Resources that meet the qualifying electricity requirements under each 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.

Washington's Energy Independence Act establishes a renewable energy target 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 and thereafter.

The Oregon Renewable Energy Act ("OREA") provides a comprehensive renewable energy policy and RPS for Oregon. Subject to certain exemptions and cost limitations established in the law, 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. PacifiCorp filed its 2011 Oregon RPS compliance report in June 2012. In November, 2012, the OPUC determined that PacifiCorp achieved compliance for the 2011 compliance period. As required by the OREA, the OPUC has approved an automatic adjustment clause to allow an electric utility, including PacifiCorp, to recover prudently incurred costs of its investments in renewable energy generating facilities and associated transmission costs.

The California RPS requires 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.

Utah's Energy Resource and Carbon Emission Reduction Initiative 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 electricity 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. While the rule was required to be finalized by the EPA by July 2012, the deadline for finalizing the rule was extended to June 2013. Assuming the final rule is issued by June 2013, PacifiCorp's generating facilities impacted by the final rule will be required to complete impingement and entrainment studies in 2014. 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 to the consolidated financial statements.

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. In briefs filed in litigation pending in the D.C. Circuit to force the EPA to meet a deadline to issue final coal combustion byproduct rules, the EPA indicated it needs until at least 2014 to review comments, formulate a risk assessment and coordinate the rule with the effluent limit guidelines. In the 112th United States Congress, efforts were undertaken, but not adopted, to regulate coal combustion byproducts under RCRA Subtitle D. Similar efforts are expected in the 113th United States Congress. 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 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 PacifiCorp's Klamath River hydroelectric system.

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, 2012, 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 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 had been triggered as of December 31, 2012, PacifiCorp would have been required to post $227 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 11 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 are and have been subject to extensive rulemaking proceedings being conducted both jointly and independently by multiple regulatory agencies, some of which have been completed and others that are expected to be finalized in 2013.

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, margin, reporting, recordkeeping and business conduct requirements primarily for "swap dealers" and "major swap participants." The Dodd-Frank Reform Act provides certain exemptions from these requirements for commercial end-users when using derivatives to hedge or mitigate commercial risk of their businesses and PacifiCorp believes it will qualify for many of these exemptions. PacifiCorp generally does not enter into over-the-counter derivative contracts for purposes unrelated to hedging or mitigating commercial risk and will not be required to register as a swap dealer or major swap participant. The outcome of remaining Dodd-Frank Reform Act rulemaking proceedings cannot be predicted but requirements resulting from these proceedings could directly impact PacifiCorp or could have impacts to energy and other markets in general that could have an impact on PacifiCorp's consolidated financial results.

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 $7.4 billion as of December 31, 2012 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, 2012, 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 44% of its total capitalization, excluding short-term debt and current maturities of long-term debt. 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, 2012, PacifiCorp's actual common stock equity percentage, as calculated under this measure, was 53.7%, and management believes that PacifiCorp could have declared a dividend of $2.5 billion under this commitment.

These commitments also restrict PacifiCorp from making any distributions to either PPW Holdings 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, 2012, 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 defers 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. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which are recognized in earnings in the periods the corresponding changes in rates occur.

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 that could limit PacifiCorp's ability to recover its costs. 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"). Total regulatory assets were $1.835 billion and total regulatory liabilities were $913 million as of December 31, 2012. 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, natural gas, coal and fuel oil 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, 2012, PacifiCorp had no derivative contracts outstanding related to hedges of interest rate risk. Refer to Notes 11 and 12 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 accounting principles generally accepted in the United States of America. 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, 2012, PacifiCorp had a net derivative liability of $121 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, 2012, PacifiCorp had a net derivative asset of $- million related to contracts where PacifiCorp uses internal models with significant unobservable inputs.

Contracts with explicit or embedded optionality are valued by separating each contract into its physical and financial forward, swap and option components. Forward and swap components are valued against the appropriate forward price curve. 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

PacifiCorp's derivative contracts are probable of inclusion in rates. Therefore, changes in the estimated fair value of derivative contracts are generally recorded as 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, 2012, PacifiCorp had $121 million recorded as a regulatory asset related to derivative contracts on the Consolidated Balance Sheets.

Pension and Other Postretirement Benefits

PacifiCorp sponsors defined benefit pension and other postretirement benefit plans that cover the majority of its employees. In addition, PacifiCorp contributes to a joint trustee plan and a subsidiary contributes to a multiemployer plan for benefits offered to certain bargaining unit employees. 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, 2012, PacifiCorp recognized a net liability totaling $587 million for the funded status of its defined benefit pension and other postretirement benefit plans. As of December 31, 2012, amounts not yet recognized as a component of net periodic benefit cost that were included in regulatory assets and AOCI totaled $776 million and $(19) 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 9 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, 2012.

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 is assumed to gradually decline to 5% in 2018, at which point the rate is assumed to remain constant. Refer to Note 9 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, 2012 Benefit Obligations:				
Discount rate	$ (77)	$ 84	$ (37)	$ 42
Effect on 2012 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 income 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 is more likely than not of being realized upon ultimate settlement. Although the ultimate resolution of PacifiCorp's federal, state and local income tax examinations is uncertain, PacifiCorp believes it has made adequate provisions for these income tax positions. The aggregate amount of any additional income 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 8 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. As of December 31, 2012, these amounts were recognized as a regulatory asset of $456 million and a regulatory liability of $21 million and will be included in rates when the temporary differences reverse.

Revenue Recognition - Unbilled Revenue

Unbilled revenue was $251 million as of December 31, 2012. 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 11 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. 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 transactions. 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.

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 include 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 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.

In 2012, PacifiCorp limited its overall hedging of net power costs and is generally not hedging beyond 36 months based largely on feedback received from external stakeholders in hedging collaborative meetings. As a result, the length of the forward position management horizon has decreased to 36 months from 48 months. Effective for the year ending December 31, 2012, PacifiCorp changed its VaR methodology to align to its updated hedging strategy. The previous VaR methodology was based on a 48-month forward position, 95.0% confidence interval and one-day holding period. The new methodology is based on a 36-month forward position, 95.0% confidence interval and one-day holding period.

As of December 31, 2012 and 2011, PacifiCorp's estimated potential one-day unfavorable impact on fair value of the electricity and natural gas commodity portfolio over the next 36 months was $10 million, as measured by the VaR computations described above. The minimum, average and maximum daily VaR (one-day holding periods) were as follows for the years ended December 31 (in millions):

	2012	2011
Minimum VaR (measured)	$ 7	$ 4
Average VaR (calculated)	10	6
Maximum VaR (measured)	15	10

PacifiCorp maintained compliance with its VaR limit procedures during the year ended December 31, 2012. 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 $55 million and $123 million as of December 31, 2012 and 2011, respectively, and shows the effects of a hypothetical 10% increase and 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 - Net Asset (Liability)	Estimated Fair Value after Hypothetical Change in Price	
		10% increase	10% decrease
As of December 31, 2012:			
Total commodity derivative contracts	$ (121)	$ (93)	$ (149)
As of December 31, 2011:			
Total commodity derivative contracts	$ (264)	$ (229)	$ (299)

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, 2012 and 2011, a regulatory asset of $121 million and $264 million, respectively, was recorded related to the net derivative liability of $121 million and $264 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 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, 7 and 12 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, 2012 and 2011, PacifiCorp had short- and long-term variable-rate obligations totaling $655 million and $1.343 billion, 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, 2012 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, 2012 and 2011.

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 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, 2012, PacifiCorp's aggregate credit exposure from wholesale activities totaled $290 million, based on settlement and mark-to-market exposures, net of collateral. As of December 31, 2012, $285 million, or 98%, 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, 2012, $5 million, or 2%, of PacifiCorp's credit exposure was with counterparties having financial characteristics deemed equivalent to investment grade by PacifiCorp based on internal review. As of December 31, 2012, two counterparties comprised $221 million, or 76%, of the aggregate credit exposure. The two 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, 2012.

Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
PacifiCorp
Portland, Oregon

We have audited the accompanying consolidated balance sheets of PacifiCorp and subsidiaries (the "Company") as of December 31, 2012 and 2011, and the related consolidated statements of operations, comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2012. 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, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Portland, Oregon
March 1, 2013

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2012	**2011**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 80	$ 47
Accounts receivable, net	671	653
Income taxes receivable	—	70
Inventories:		
Materials and supplies	202	196
Fuel	266	237
Deferred income taxes	112	129
Regulatory assets	62	74
Other current assets	75	77
Total current assets	1,468	1,483
Property, plant and equipment, net	18,057	17,374
Regulatory assets	1,773	1,810
Other assets	430	439
Total assets	$ 21,728	$ 21,106

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, 2012	As of December 31, 2011
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 467	$ 582
Income taxes payable	48	—
Accrued employee expenses	77	72
Accrued interest	113	105
Accrued property and other taxes	54	66
Derivative contracts	49	90
Short-term debt	—	688
Current portion of long-term debt and capital lease obligations	267	19
Regulatory liabilities	62	67
Other current liabilities	147	125
Total current liabilities	1,284	1,814
Regulatory liabilities	851	826
Long-term debt and capital lease obligations	6,594	6,194
Deferred income taxes	4,168	3,863
Other long-term liabilities	1,187	1,097
Total liabilities	14,084	13,794
Commitments and contingencies (Note 13)		
Shareholders' equity:		
Preferred stock	41	41
Common stock - 750 shares authorized, no par value, 357 shares issued and outstanding	—	—
Additional paid-in capital	4,479	4,479
Retained earnings	3,136	2,801
Accumulated other comprehensive loss, net	(12)	(9)
Total shareholders' equity	7,644	7,312
Total liabilities and shareholders' equity	$ 21,728	$ 21,106

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,		
	2012	2011	2010
Operating revenue	$ 4,882	$ 4,586	$ 4,432
Operating costs and expenses:			
Energy costs	1,818	1,636	1,618
Operations and maintenance	1,242	1,103	1,081
Depreciation and amortization	640	611	561
Taxes, other than income taxes	161	152	136
Total operating costs and expenses	3,861	3,502	3,396
Operating income	1,021	1,084	1,036
Other income (expense):			
Interest expense	(380)	(392)	(387)
Allowance for borrowed funds	29	25	45
Allowance for equity funds	58	47	79
Interest income	4	5	5
Other, net	2	(1)	(1)
Total other income (expense)	(287)	(316)	(259)
Income before income tax expense	734	768	777
Income tax expense	197	213	211
Net income	$ 537	$ 555	$ 566

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,		
	2012	2011	2010
Net income	$ 537	$ 555	$ 566
Other comprehensive loss, net of tax —			
Unrecognized amounts on retirement benefits, net of tax of $(2), $(1) and $(1)	(3)	(2)	(1)
Comprehensive income	$ 534	$ 553	$ 565

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, 2009	$ 41	$ —	$ 4,379	$ 2,234	$ (6)	$ 84	$ 6,732
Deconsolidation of Bridger Coal Company	—	—	—	—	—	(84)	(84)
Net income	—	—	—	566	—	—	566
Other comprehensive loss	—	—	—	—	(1)	—	(1)
Contributions	—	—	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
Net income	—	—	—	537	—	—	537
Other comprehensive loss	—	—	—	—	(3)	—	(3)
Preferred stock dividends declared	—	—	—	(2)	—	—	(2)
Common stock dividends declared	—	—	—	(200)	—	—	(200)
Balance, December 31, 2012	$ 41	$ —	$ 4,479	$ 3,136	$ (12)	$ —	$ 7,644

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,		
	2012	2011	2010
Cash flows from operating activities:			
Net income	$ 537	$ 555	$ 566
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	640	611	561
Deferred income taxes and amortization of investment tax credits	312	374	710
Changes in regulatory assets and liabilities	1	(23)	4
Other, net	(32)	(25)	(58)
Changes in other operating assets and liabilities:			
Accounts receivable and other assets	(17)	(42)	(14)
Derivative collateral, net	68	4	(102)
Inventories	(35)	(59)	(26)
Income taxes, net	118	275	(96)
Accounts payable and other liabilities	35	(34)	(135)
Net cash flows from operating activities	1,627	1,636	1,410
Cash flows from investing activities:			
Capital expenditures	(1,346)	(1,506)	(1,607)
Other, net	4	(23)	(6)
Net cash flows from investing activities	(1,342)	(1,529)	(1,613)
Cash flows from financing activities:			
Net (repayments of) proceeds from short-term debt	(688)	652	36
Proceeds from long-term debt	749	399	—
Repayments and redemptions of long-term debt and capital lease obligations	(102)	(588)	(16)
Proceeds from equity contributions	—	—	100
Common stock dividends	(200)	(550)	—
Preferred stock dividends	(2)	(2)	(2)
Other, net	(9)	(2)	(1)
Net cash flows from financing activities	(252)	(91)	117
Net change in cash and cash equivalents	33	16	(86)
Cash and cash equivalents at beginning of period	47	31	117
Cash and cash equivalents at end of period	$ 80	$ 47	$ 31

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 retail customers, including residential, commercial, industrial, irrigation 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 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.

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 defers 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. Regulatory assets and liabilities are established to reflect the impacts of these deferrals, which are recognized in earnings in the periods the corresponding changes in rates occur.

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 that could limit PacifiCorp's ability to recover its costs. 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. 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 money market mutual funds, United States Treasury Bills 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, 2012 and 2011, 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.

Allowance for Doubtful Accounts

Accounts receivable are stated at the outstanding principal amount, net of an estimated allowance 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):

	2012	2011	2010
Beginning balance	$ 9	$ 8	$ 7
Charged to operating costs and expenses, net	14	13	12
Write-offs, net	(14)	(12)	(11)
Ending balance	$ 9	$ 9	$ 8

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 agreements 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 derivative 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 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, net of any 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, 2012 and 2011, unbilled revenue was $251 million and $237 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. As of December 31, 2012 and 2011, these amounts were recognized as regulatory assets of $456 million and $444 million, respectively, and regulatory liabilities of $21 million and $22 million, 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. Changes in deferred income tax assets and liabilities attributable to changes in enacted income tax rates are charged or credited to income tax expense in the period of enactment. Valuation allowances are established for certain deferred income tax assets where realization is not likely.

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 $34 million and $38 million as of December 31, 2012 and 2011, respectively.

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 tax returns are subject to continuous examinations by federal, state and local income 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 is more likely than not of being realized upon ultimate settlement. Although the ultimate resolution of PacifiCorp's federal, state and local income tax examinations is uncertain, PacifiCorp believes it has made adequate provisions for these income tax positions. The aggregate amount of any additional income 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 February 2013, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2013-02, which amends FASB Accounting Standards Codification ("ASC") Topic 220, "Comprehensive Income." The amendments in this guidance require an entity to provide information about the amounts reclassified out of AOCI by component. In addition, an entity is required to present, either on the face of the financial statements or in the notes, significant amounts reclassified out of AOCI by the respective line items of net income if the amount reclassified is required under GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required by GAAP that provide additional detail about those amounts. This guidance is effective prospectively for interim and annual reporting periods beginning after December 15, 2012. PacifiCorp is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In December 2011, the FASB issued ASU No. 2011-11, which amends FASB 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. In January 2013, the FASB issued ASU No. 2013-01, which also amends FASB ASC Topic 210 to clarify that the scope of ASU No. 2011-11 only applies to derivative instruments, repurchase agreements, reverse purchase agreements and securities borrowing and securities lending transactions that are either being offset or are subject to an enforceable master netting arrangement or similar agreement. ASU No. 2013-01 is also 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 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. 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. PacifiCorp adopted this guidance on January 1, 2012 and elected the two separate but consecutive statements option.

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 adopted ASU No. 2011-04 on January 1, 2012. 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	2012	2011
Property, plant and equipment:			
Generation	20 - 80 years	$ 10,952	$ 10,429
Transmission	25 - 75 years	4,732	4,503
Distribution	20 - 65 years	5,859	5,683
Intangible plant[1]	5 - 65 years	850	854
Other	5 - 50 years	1,631	1,586
Property, plant and equipment in service		24,024	23,055
Accumulated depreciation and amortization		(7,222)	(6,888)
Net property, plant and equipment in service		16,802	16,167
Construction work-in-progress		1,255	1,207
Total property, plant and equipment, net		$ 18,057	$ 17,374

(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 each of the years ended December 31, 2012, 2011 and 2010.

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, 2012 and 2011 and accumulated depreciation of $113 million and $107 million as of December 31, 2012 and 2011, 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, 2012 (dollars in millions):

	PacifiCorp Share	Facility in Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
Jim Bridger Nos. 1 - 4	67%	$ 1,087	$ 505	$ 33
Hunter No. 1	94	391	143	19
Hunter No. 2	60	301	81	—
Wyodak	80	450	158	2
Colstrip Nos. 3 and 4	10	223	119	1
Hermiston [(1)]	50	172	56	1
Craig Nos. 1 and 2	19	177	92	4
Hayden No. 1	25	55	24	1
Hayden No. 2	13	32	16	—
Foote Creek	79	37	20	—
Transmission and distribution facilities	Various	325	53	1
Total		$ 3,250	$ 1,267	$ 62

(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 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	2012	2011
Employee benefit plans[1]	9 years	$ 776	$ 727
Deferred income taxes[2]	33 years	456	444
Unrealized loss on derivative contracts	1 year	121	264
Unamortized contract values[3]	9 years	166	187
Deferred net power costs	2 years	135	130
Other	Various	181	132
Total regulatory assets		$ 1,835	$ 1,884
Reflected as:			
Current assets		$ 62	$ 74
Noncurrent assets		1,773	1,810
Total regulatory assets		$ 1,835	$ 1,884

(1) Represents amounts not yet recognized as a component of net periodic benefit cost that are expected to be included in rates when recognized.

(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.

PacifiCorp had regulatory assets not earning a return on investment of $1.618 billion and $1.662 billion as of December 31, 2012 and 2011, 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	2012	2011
Cost of removal[1]	33 years	$ 810	$ 782
Deferred income taxes	Various	21	22
Other	Various	82	89
Total regulatory liabilities		$ 913	$ 893
Reflected as:			
Current liabilities		$ 62	$ 67
Noncurrent liabilities		851	826
Total regulatory liabilities		$ 913	$ 893

(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) Short-term Debt and Other Financing Agreements

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

2012:		
Available revolving credit facilities	$	1,230
Less:		
Short-term debt		—
Letters of credit supporting tax-exempt bond obligations and collateral requirements of commodity contracts		(602)
Net revolving credit facilities available	$	628
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

In June 2012, PacifiCorp replaced its existing $635 million unsecured revolving credit facility with a $600 million unsecured revolving credit facility expiring in June 2017. This facility is for general corporate purposes including supporting PacifiCorp's commercial paper program and provides for the issuance of letters of credit. Additionally, PacifiCorp has an unsecured revolving credit facility, which had $720 million available until July 2012 and has $630 million available until July 2013, which supports PacifiCorp's commercial paper program and certain variable-rate tax-exempt bond obligations. These credit facilities have a variable interest rate based on the London Interbank Offered Rate or a base rate, at PacifiCorp's option, plus a spread that varies based on PacifiCorp's credit ratings for its senior unsecured long-term debt securities. As of December 31, 2011, the weighted-average interest rate on commercial paper borrowings outstanding was 0.51%. The revolving credit facilities require that PacifiCorp's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.65 to 1.0 as of the last day of each quarter for the $600 million credit facility or at any time for the $630 million credit facility. As of December 31, 2012, PacifiCorp was in compliance with the covenants of its revolving credit facilities.

As of December 31, 2012 and 2011, PacifiCorp had $602 million and $601 million, respectively, of letters of credit issued under committed arrangements, of which $602 million and $304 million, respectively, were issued under the revolving credit facilities. These letters of credit support PacifiCorp's variable-rate tax-exempt bond obligations and certain collateral requirements of commodity contracts, were fully available as of December 31, 2012 and 2011, and expire periodically from March 2013 through November 2013.

As of December 31, 2012, PacifiCorp had approximately $14 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, 2012 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.

(7) 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):

	2012			2011	
	Principal Amount	Carrying Value	Average Interest Rate	Carrying Value	Average Interest Rate
First mortgage bonds:					
5.0% to 8.8%, due through 2017	$ 441	$ 441	5.5%	$ 458	5.6%
3.0% to 8.5%, due 2018 to 2022	1,875	1,872	4.8	1,422	5.4
6.7% to 8.2%, due 2023 to 2026	249	249	7.0	249	7.0
7.7% due 2031	300	300	7.7	299	7.7
5.3% to 6.3%, due 2034 to 2037	2,050	2,047	5.9	2,047	5.9
4.1% to 6.4%, due 2038 to 2042	1,250	1,242	5.6	943	6.1
Tax-exempt bond obligations:					
Variable rates, due 2013(1)(2)	41	41	0.14	41	0.10
Variable rates, due 2014 to 2025(2)	325	325	0.15	325	0.24
Variable rates, due 2016 to 2024(1)(2)	221	221	0.15	221	0.09
Variable rates, due 2014 to 2025(1)(3)	68	68	4.02	68	4.02
5.63% to 5.65%, due 2021 to 2023(1)	—	—	—	71	5.64
6.15%, due 2030	—	—	—	13	6.15
Total long-term debt	6,820	6,806		6,157	
Capital lease obligations:					
8.75% to 14.81%, due through 2036	55	55	11.30	56	11.37
Total long-term debt and capital lease obligations	$ 6,875	$ 6,861		$ 6,213	

Reflected as:

	2012	2011
Current portion of long-term debt and capital lease obligations	$ 267	$ 19
Long-term debt and capital lease obligations	6,594	6,194
Total long-term debt and capital lease obligations	$ 6,861	$ 6,213

(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 as of December 31, 2012. These letters of credit were undrawn as of December 31, 2012 and expire periodically through November 2013.

(3) Interest rates are currently fixed at 3.90% to 4.13% 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 through the payment of a make-whole premium. Variable-rate tax-exempt bond obligations are generally redeemable at par value.

In January 2012, PacifiCorp issued $350 million of its 2.95% First Mortgage Bonds due February 2022 and $300 million of its 4.10% First Mortgage Bonds due February 2042. The net proceeds were used to repay short-term debt, fund capital expenditures and for general corporate purposes. In March 2012, PacifiCorp issued an additional $100 million of its 2.95% First Mortgage Bonds due February 2022. The net proceeds were used to redeem $84 million of tax-exempt bond obligations prior to scheduled maturity with a weighted average interest rate of 5.72%, to repay short-term debt 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 $850 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.

The issuance of PacifiCorp's first mortgage bonds is limited by available property, earnings tests and other provisions of PacifiCorp's mortgage. Approximately $23 billion of PacifiCorp's eligible property (based on original cost) was subject to the lien of the mortgage as of December 31, 2012.

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 $55 million and $56 million as of December 31, 2012 and 2011, respectively, were included in property, plant and equipment, net in the Consolidated Balance Sheets.

As of December 31, 2012, the annual maturities of long-term debt and capital lease obligations, excluding unamortized discounts and including interest on capital lease obligations, for 2013 and thereafter are as follows (in millions):

	Long-term Debt	Capital Lease Obligations	Total
2013	$ 261	$ 12	$ 273
2014	253	8	261
2015	122	7	129
2016	57	7	64
2017	52	11	63
Thereafter	6,075	70	6,145
Total	6,820	115	6,935
Unamortized discount	(14)	—	(14)
Amounts representing interest	—	(60)	(60)
Total	$ 6,806	$ 55	$ 6,861

(8) Income Taxes

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

	2012	2011	2010
Current:			
Federal	$ (112)	$ (151)	$ (498)
State	(3)	(10)	(1)
Total	(115)	(161)	(499)
Deferred:			
Federal	283	338	684
State	33	40	30
Total	316	378	714
Investment tax credits	(4)	(4)	(4)
Total income tax expense	$ 197	$ 213	$ 211

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:

	2012	2011	2010
Federal statutory income tax rate	35%	35%	35%
State income taxes, net of federal income tax benefit	3	2	2
Federal income tax credits[1]	(9)	(10)	(8)
Effects of ratemaking	(1)	—	(2)
Other	(1)	1	—
Effective income tax rate	27%	28%	27%

(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):

	2012	2011
Deferred income tax assets:		
Regulatory liabilities	$ 346	$ 339
Employee benefits	219	212
Derivative contracts	46	100
Unamortized contract values	63	72
State carryforwards	69	62
Other	213	155
	956	940
Deferred income tax liabilities:		
Property, plant and equipment	(4,269)	(3,919)
Regulatory assets	(695)	(715)
Other	(48)	(40)
	(5,012)	(4,674)
Net deferred income tax liability	$ (4,056)	$ (3,734)
Reflected as:		
Deferred income taxes - current assets	$ 112	$ 129
Deferred income taxes - noncurrent liabilities	(4,168)	(3,863)
	$ (4,056)	$ (3,734)

As of December 31, 2012, PacifiCorp has available $69 million of state carryforwards, principally for net operating losses, which expire at various intervals between 2013 and 2032.

The United States Internal Revenue Service has closed its examination of PacifiCorp's income tax returns through the March 31, 2006 tax year. State jurisdictions have closed their examinations of PacifiCorp's income tax returns through 1993.

As of December 31, 2012 and 2011, net unrecognized tax benefits totaled $47 million and $64 million, respectively, which included $- million and $8 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.

(9) Employee Benefit Plans

PacifiCorp sponsors defined benefit pension and other postretirement benefit plans that cover the majority of its employees, as well as a defined contribution 401(k) employee savings plan ("401(k) Plan"). In addition, PacifiCorp contributes to a joint trustee pension plan and a subsidiary contributes to a multiemployer pension plan 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 all non-union employees hired after January 1, 2008. 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 limited 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 Amendment

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.

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		
	2012	2011	2010	2012	2011	2010
Service cost	$ 7	$ 10	$ 12	$ 7	$ 7	$ 6
Interest cost	61	63	66	28	31	31
Expected return on plan assets	(74)	(75)	(74)	(30)	(30)	(30)
Net amortization	34	20	13	4	18	15
Net periodic benefit cost	$ 28	$ 18	$ 17	$ 9	$ 26	$ 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	
	2012	2011	2012	2011
Plan assets at fair value, beginning of year	$ 931	$ 960	$ 384	$ 389
Employer contributions	49	71	9	28
Participant contributions	—	—	7	9
Actual return on plan assets	120	(13)	52	(4)
Benefits paid	(88)	(87)	(28)	(38)
Plan assets at fair value, end of year	$ 1,012	$ 931	$ 424	$ 384

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

	Pension		Other Postretirement	
	2012	2011	2012	2011
Benefit obligation, beginning of year	$ 1,291	$ 1,236	$ 575	$ 581
Service cost	7	10	7	7
Interest cost	61	63	28	31
Participant contributions	—	—	7	9
Plan amendments	—	(4)	—	(54)
Actuarial loss	120	73	43	36
Benefits paid, net of Medicare subsidy	(88)	(87)	(28)	(35)
Benefit obligation, end of year	$ 1,391	$ 1,291	$ 632	$ 575
Accumulated benefit obligation, end of year	$ 1,390	$ 1,289		

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	
	2012	2011	2012	2011
Plan assets at fair value, end of year	$ 1,012	$ 931	$ 424	$ 384
Less - Benefit obligation, end of year	1,391	1,291	632	575
Funded status	$ (379)	$ (360)	$ (208)	$ (191)
Amounts recognized on the Consolidated Balance Sheets:				
Other current liabilities	$ (4)	$ (4)	$ —	$ —
Other long-term liabilities	(375)	(356)	(208)	(191)
Amounts recognized	$ (379)	$ (360)	$ (208)	$ (191)

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 $44 million and $41 million as of December 31, 2012 and 2011, 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.

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	
	2012	2011	2012	2011
Net loss	$ 660	$ 630	$ 214	$ 206
Prior service credit	(37)	(45)	(40)	(46)
Regulatory deferrals	(5)	(7)	3	3
Total	$ 618	$ 578	$ 177	$ 163

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2012 and 2011 is as follows (in millions):

	Regulatory Asset	Accumulated Other Comprehensive Loss	Total
Pension			
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
Net loss arising during the year	68	6	74
Net amortization	(33)	(1)	(34)
Total	35	5	40
Balance, December 31, 2012	$ 599	$ 19	$ 618

	Regulatory Asset
Other Postretirement	
Balance, December 31, 2010	$ 165
Net loss arising during the year	70
Prior service credit arising during the year	(46)
Reduction in net transition obligation	(8)
Net amortization	(18)
Total	(2)
Balance, December 31, 2011	163
Net loss arising during the year	18
Net amortization	(4)
Total	14
Balance, December 31, 2012	$ 177

The net loss, prior service credit and regulatory deferrals that will be amortized in 2013 into net periodic benefit cost are estimated to be as follows (in millions):

	Net Loss	Prior Service Credit	Regulatory Deferrals	Total
Pension	$ 57	$ (8)	$ (1)	$ 48
Other postretirement	15	(7)	1	9
Total	$ 72	$ (15)	$ —	$ 57

Plan Assumptions

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

	Pension			Other Postretirement		
	2012	2011	2010	2012	2011	2010
Benefit obligations as of December 31:						
Discount rate	4.05%	4.90%	5.35%	4.10%	4.95%	5.45%
Rate of compensation increase	3.00	3.50	3.50	N/A	N/A	N/A
Net periodic benefit cost for the years ended December 31:						
Discount rate	4.90%	5.35%	5.80%	4.95%	5.45%	5.85%
Expected return on plan assets	7.50	7.50	7.75	7.50	7.50	7.75
Rate of compensation increase	3.50	3.50	3.00	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.

	2012	2011
Assumed healthcare cost trend rates as of December 31:		
Healthcare cost trend rate assumed for next year	8.00%	8.50%
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	2018	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	48	(38)

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be $64 million and $13 million, respectively, during 2013. 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 2013 through 2017 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments		
		Other Postretirement	
	Pension	Gross	Medicare Subsidy
2013	$ 100	$ 36	$ —
2014	102	37	—
2015	104	37	—
2016	106	39	(1)
2017	103	41	(1)
2018 - 2022	482	207	(4)

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 equity and debt 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 long-term 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, 2012:

	Pension[1]	Other Postretirement[1]
	%	%
Equity securities[2]	53 - 57	61 - 65
Debt securities[2]	33 - 37	33 - 37
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 plan are held in 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 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, 2012				
Cash equivalents	$ 1	$ 8	$ —	$ 9
Debt securities:				
United States government obligations	48	—	—	48
International government obligations	—	67	—	67
Corporate obligations	—	64	—	64
Municipal obligations	—	7	—	7
Agency, asset and mortgage-backed obligations	—	34	—	34
Equity securities:				
United States companies	383	—	—	383
International companies	7	—	—	7
Investment funds[2]	112	185	—	297
Limited partnership interests[3]	—	—	96	96
Total	$ 551	$ 365	$ 96	$ 1,012
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

(1) Refer to Note 12 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 60% and 40%, respectively, for 2012 and 59% and 41%, respectively, for 2011. Additionally, these funds are invested in United States and international securities of approximately 42% and 58%, respectively, for 2012 and 49% and 51%, respectively, for 2011.

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

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
As of December 31, 2012				
Cash and cash equivalents	$ 4	$ —	$ —	$ 4
Debt securities:				
United States government obligations	4	—	—	4
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	137	—	—	137
International companies	3	—	—	3
Investment funds[(2)]	152	103	—	255
Limited partnership interests[(3)]	—	—	7	7
Total	$ 300	$ 117	$ 7	$ 424
As of 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

(1) Refer to Note 12 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 2012 and 2011. Additionally, these funds are invested in United States and international securities of approximately 66% and 34%, respectively, for 2012 and 69% and 31%, respectively, for 2011.

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

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. Most 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 estimated 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. One of the limited partnerships is valued at the unit price calculated by the general partner primarily based on independent appraised values of the underlying property holdings.

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):

	Limited Partnership Interests	
	Pension	Other Postretirement
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
Actual return on plan assets still held at December 31, 2012	7	—
Purchases, sales, distributions and settlements	18	1
Balance, December 31, 2012	$ 96	$ 7

Multiemployer and Joint Trustee Pension Plans

PacifiCorp contributes to the PacifiCorp/IBEW Local 57 Retirement Trust Fund ("Local 57 Trust Fund") (plan number 001) and a subsidiary contributes to the United Mine Workers of America 1974 Pension Plan ("UMWA Pension Plan") (plan number 002). Contributions to these pension plans are based on the terms of collective bargaining agreements.

The Local 57 Trust Fund is a joint trustee plan such that the board of trustees is represented by an equal number of trustees from PacifiCorp and the union. The Local 57 Trust Fund was established pursuant to the provisions of the Taft-Hartley Act and was formed with the ability for other employers to participate in the plan.

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 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. 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. Furthermore, to the extent a participating employer defaults on its obligation to the plan, the remaining employers may be allocated a share of the defaulting employer's obligation for unfunded vested benefits. Under the terms of the UMWA Pension Plan, in the event the mining operations cease, PacifiCorp's subsidiary may be subject to a withdrawal liability.

The following table presents PacifiCorp's and its subsidiary's participation in individually significant joint trustee and 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] 2012	2011	2010	Funding improvement plan	Surcharge imposed under PPA	Contributions[2] 2012	2011	2010	Year contributions to plan exceeded more than 5% of total contributions[4]
UMWA Pension Plan	52-1050282	Orange	Orange	Green[3]	Implemented	None	$ 3	$ 3	$ 3	None
Local 57 Trust Fund	87-0640888	At least 80%	At least 80%	At least 80%	None	None	$ 12	$ 12	$ 9	2011, 2010, 2009

(1) Among other factors, multiemployer plans in the red zone are generally less than 65 percent funded; multiemployer plans in the yellow zone either (a) are at least 65 percent but less than 80 percent funded or (b) have an accumulated funding deficiency for such plan year, or are projected to have such an accumulated funding deficiency for any of the six succeeding plan years; multiemployer plans in the orange zone meet both of the criteria for yellow zone; and multiemployer plans in the green zone are at least 80 percent funded. Multiemployer plans in the red, yellow, orange or green zones are also referred to as being in critical, endangered, seriously endangered or neither endangered nor critical status, respectively.

(2) PacifiCorp's and its subsidiary's minimum contributions to the plans are based on the amount of wages paid to employees covered by the Local 57 Trust Fund collective bargaining agreement and the number of mining hours worked for the UMWA Pension Plan, respectively, 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 orange for the plan year beginning July 1, 2010.

(4) For the UMWA Pension Plan, information is for plan years beginning July 1, 2010 and 2009. Information for the plan years beginning July 1, 2012 and 2011 is not available. For the Local 57 Trust Fund, information is for plan years beginning July 1, 2011, 2010 and 2009. Information for the plan year beginning July 1, 2012 is not yet available.

Although the collective bargaining agreements governing the UMWA Pension Plan and the Local 57 Trust Fund expired in January 2013, operations will continue under the provisions of the agreements until such time that new agreements are reached or the existing agreements are terminated.

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 $36 million, $38 million and $39 million for the years ended December 31, 2012, 2011 and 2010, respectively.

(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 in accordance with accepted regulatory practices. Cost of removal regulatory liabilities totaled $810 million and $782 million as of December 31, 2012 and 2011, respectively.

The following table reconciles the beginning and ending balances of PacifiCorp's ARO liabilities for the years ended December 31 (in millions):

	2012	2011
Beginning balance	$ 123	$ 105
Change in estimated costs[1]	17	2
Additions	4	29
Retirements	(22)	(19)
Accretion	5	6
Ending balance	$ 127	$ 123
Reflected as:		
Other current liabilities	$ 13	$ 20
Other long-term liabilities	114	103
	$ 127	$ 123

(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) 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 12 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):

	Other Current Assets	Other Assets	Derivative Contracts - Current Liabilities	Other Long-term Liabilities	Total
As of December 31, 2012					
Not designated as hedging contracts[1]:					
Commodity assets	$ 10	$ 3	$ 18	$ 1	$ 32
Commodity liabilities	(2)	(2)	(122)	(27)	(153)
Total	8	1	(104)	(26)	(121)
Total derivatives	8	1	(104)	(26)	(121)
Cash collateral receivable	—	—	55	—	55
Total derivatives - net basis	$ 8	$ 1	$ (49)	$ (26)	$ (66)
As of December 31, 2011					
Not designated as hedging contracts[1]:					
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)

(1) PacifiCorp's commodity derivatives are generally included in rates and as of December 31, 2012 and 2011, a regulatory asset of $121 million and $264 million, respectively, was recorded related to the net derivative liability of $121 million and $264 million, respectively.

The following table reconciles the beginning and ending balances of PacifiCorp's regulatory assets and summarizes the pre-tax gains and losses on commodity derivative contracts recognized in regulatory assets, as well as amounts reclassified to earnings for the years ended December 31 (in millions):

	2012	2011
Beginning balance	$ 264	$ 487
Changes in fair value recognized in regulatory assets	45	(2)
Net losses reclassified to unamortized contract value regulatory asset	—	(168)
Net gains reclassified to operating revenue	38	18
Net losses reclassified to energy costs	(226)	(71)
Ending balance	$ 121	$ 264

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	2012	2011
Electricity sales	Megawatt hours	(1)	(2)
Natural gas purchases	Decatherms	74	96
Fuel oil purchases	Gallons	16	17

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, 2012, 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 $153 million and $378 million as of December 31, 2012 and 2011, respectively, for which PacifiCorp had posted collateral of $56 million and $125 million, respectively, in the form of cash deposits and letters of credit. If all credit-risk-related contingent features for derivative contracts in liability positions had been triggered as of December 31, 2012 and 2011, PacifiCorp would have been required to post $73 million and $155 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.

(12) 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, 2012					
Assets:					
Commodity derivatives	$ —	$ 32	$ —	$ (23)	$ 9
Money market mutual funds(2)	73	—	—	—	73
	$ 73	$ 32	$ —	$ (23)	$ 82
Liabilities - Commodity derivatives	$ —	$ (153)	$ —	$ 78	$ (75)
As of December 31, 2011					
Assets:					
Commodity derivatives	$ —	$ 114	$ 1	$ (100)	$ 15
Money market mutual funds(2)	33	—	—	—	33
	$ 33	$ 114	$ 1	$ (100)	$ 48
Liabilities - Commodity derivatives	$ —	$ (379)	$ —	$ 223	$ (156)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $55 million and $123 million as of December 31, 2012 and 2011, 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 11 for further discussion regarding PacifiCorp's risk management and hedging activities.

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):

	2012	2011	2010
Beginning balance	$ 1	$ (345)	$ (380)
Changes in fair value recognized in regulatory assets	1	132	(38)
Contracts designated as normal purchases or normal sales	—	168	—
Settlements	(2)	46	73
Ending balance	$ —	$ 1	$ (345)

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 were reclassified from derivative contracts to other assets and liabilities. The frozen liability and associated regulatory asset are being 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 is a Level 2 fair value measurement and 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):

	2012		2011	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 6,806	$ 8,350	$ 6,157	$ 7,804

(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. 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.

USA Power

In October 2005, prior to MEHC's ownership of PacifiCorp, PacifiCorp was added as a defendant to a lawsuit originally filed in February 2005 in the Third District Court of Salt Lake County, Utah ("Third District Court") by USA Power, LLC, USA Power Partners, LLC and Spring Canyon Energy, LLC (collectively, the "Plaintiff"). The Plaintiff'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 in regard to the Plaintiff's 2002 and 2003 proposals to build a natural gas-fueled generating facility in Juab County, Utah. In October 2007, the Third District Court granted PacifiCorp's motion for summary judgment on all counts and dismissed the Plaintiff's claims in their entirety. In February 2008, the Plaintiff filed a petition requesting consideration by the Utah Supreme Court. In May 2010, the Utah Supreme Court reversed summary judgment and remanded the case back to the Third District Court for further consideration, which led to a trial that began in April 2012. In May 2012, the jury reached a verdict in favor of the Plaintiff on its claims. The jury awarded damages to the Plaintiff for breach of contract and misappropriation of a trade secret in the amounts of $18 million for actual damages and $113 million for unjust enrichment. In May 2012, the Plaintiff filed a motion seeking exemplary damages. Under the Utah Uniform Trade Secrets law, the judge may award exemplary damages in an additional amount not to exceed twice the original award. The Plaintiff also filed a motion to seek recovery of attorneys' fees in an amount equal to 40% of all amounts ultimately awarded in the case. In October 2012, PacifiCorp filed post-trial motions for a judgment notwithstanding the verdict and a new trial (collectively, "PacifiCorp's post-trial motions"). The trial judge stayed briefing on the Plaintiff's motions, pending resolution of PacifiCorp's post-trial motions. As a result of a hearing in December 2012, the trial judge denied PacifiCorp's post-trial motions with the exception of reducing the aggregate amount of damages to $113 million. In January 2013, the Plaintiff filed a motion for prejudgment interest and PacifiCorp filed its responses to the Plaintiff's post-trial motions for exemplary damages and attorney fees. A final judgment has not been rendered, and a ruling on the Plaintiff's motions for exemplary damages, prejudgment interest and attorneys' fees is expected to be issued in 2013. PacifiCorp strongly disagrees with the verdict and plans to vigorously pursue all appellate measures once a final judgment is rendered. As of December 31, 2012, PacifiCorp accrued $113 million, plus estimated obligations for the Plaintiff's motions, and believes the likelihood of any additional material loss is remote; however, any additional awards against PacifiCorp could also have a material effect on the consolidated financial results. Any payment of damages will be at the end of the appeal process, which could take as long as several years.

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. PacifiCorp engaged in settlement discussions with certain of the parties to the proceeding, which have been approved by the FERC. The outcome of such settlements is not expected to have a material impact on PacifiCorp's consolidated financial results. A FERC hearing with all parties has been set for April 2013.

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 Klamath hydroelectric system is currently operating under annual licenses with the FERC. 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 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 with the FERC. In November 2011, bills were introduced in both chambers of the 112th 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. These bills are pending re-introduction into the 113th United States Congress.

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 into trust accounts maintained by the OPUC. PacifiCorp has begun collection of surcharges from California customers for their share of dam removal costs, as approved by the California Public Utilities Commission ("CPUC"), and is depositing the proceeds into trust accounts maintained by the CPUC. PacifiCorp is authorized to collect the surcharges through 2019.

As of December 31, 2012, PacifiCorp's assets included $115 million of costs associated with the Klamath hydroelectric system's 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 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 Idaho and Washington general rate cases, which were settled in January 2012 and March 2012, respectively, without a decision on this matter. As part of the September 2012 Utah general rate case order, the Utah Public Service Commission approved recovery of Utah's share of costs associated with the Klamath hydroelectric system's mainstem dams and the associated relicensing and settlement costs through December 31, 2022.

Hydroelectric Commitments

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 $184 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, 2012 are as follows (in millions):

	2013	2014	2015	2016	2017	2018 and Thereafter	Total
Contract type:							
Purchased electricity contracts	$ 178	$ 112	$ 113	$ 94	$ 69	$ 450	$ 1,016
Fuel contracts	666	646	525	411	389	1,978	4,615
Construction commitments	408	158	25	13	10	60	674
Transmission	105	97	75	68	61	671	1,077
Operating leases and easements	6	5	4	3	2	44	64
Maintenance, service and other contracts	31	22	12	8	12	71	156
Total commitments	$ 1,394	$ 1,040	$ 754	$ 597	$ 543	$ 3,274	$ 7,602

Purchased Electricity Contracts

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. Rent expense related to those power purchase agreements that meet the definition of an operating lease totaled $19 million for 2012, $28 million for 2011 and $26 million for 2010.

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 2012, 2011 and 2010 energy sources.

Fuel Contracts

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, 2012, PacifiCorp had the following 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 mid-2013 and (b) another segment of the Energy Gateway Transmission Expansion Program that is expected to be placed in service within the next several years, depending on siting, permitting and construction schedules.

- PacifiCorp is constructing the 645-megawatt Lake Side 2 combined-cycle combustion turbine natural gas-fueled generating facility, 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 certain operating facilities, office space, land and equipment 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 $14 million for 2012, $18 million for 2011 and $15 million for 2010.

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 outstanding was as follows as of December 31 (shares in thousands, dollars in millions, except per share amounts):

	Redemption Price Per Share	2012 Shares	2012 Amount	2011 Shares	2011 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

PacifiCorp also has 16 million shares of No Par Serial Preferred Stock authorized, but no shares were issued or outstanding as of December 31, 2012 and 2011.

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, 2012 and 2011.

(15) Common Shareholder's Equity

In January 2013, PacifiCorp declared and paid a dividend of $150 million to PPW Holdings LLC, a direct wholly owned subsidiary of MEHC and PacifiCorp's direct parent company.

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 equity below specified percentages of defined capitalization. As of December 31, 2012, 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 equity below 44% of its total capitalization, excluding short-term debt and current maturities of long-term debt. 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, 2012, PacifiCorp's actual common equity percentage, as calculated under this measure, was 53.7%, and PacifiCorp would have been permitted to dividend $2.5 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, 2012, 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 Note 6.

(16) Components of Accumulated Other Comprehensive Loss, Net

Accumulated other comprehensive loss, net consists of unrecognized amounts on retirement benefits, net of tax, of $12 million and $9 million as of December 31, 2012 and 2011, respectively.

(17) Variable-Interest Entities

PacifiCorp holds an undivided interest in 50% of the 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, 2012, 2011 and 2010. 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 Company ("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 $187 million and $204 million as of December 31, 2012 and 2011, 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 $15 million, $16 million and $9 million during the years ended December 31, 2012, 2011 and 2010, respectively. Payables associated with these administrative services were $1 million and $7 million as of December 31, 2012 and 2011, respectively. PacifiCorp also receives payments for services performed by PacifiCorp for MEHC and its affiliates primarily related to technology services and direct-assigned employees. These services were $3 million during the year ended December 31, 2012 and $2 million during each of the years ended December 31, 2011 and 2010. Receivables associated with these activities were $1 million and $- million as of December 31, 2012 and 2011, 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 $5 million, $6 million and $5 million during the years ended December 31, 2012, 2011 and 2010, respectively. Payables associated with these services were $1 million and $- million as of December 31, 2012 and 2011, 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 $34 million, $33 million and $30 million during the years ended December 31, 2012, 2011 and 2010, respectively. As of December 31, 2012 and 2011, PacifiCorp had $2 million and $1 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 was not renewed. Premium expenses were $2 million and $7 million during the years ended December 31, 2011 and 2010, respectively. Receivables for claims were $2 million and $6 million as of December 31, 2012 and 2011, respectively. Proceeds from claims were $6 million, $16 million and $14 million during the years ended December 31, 2012, 2011 and 2010, 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, 2012, income taxes payable to MEHC were $48 million, and as of December 31, 2011, income taxes receivable from MEHC were $70 million. For the years ended December 31, 2012, 2011 and 2010, cash received for income taxes from MEHC totaled $215 million, $425 million and $395 million, respectively.

PacifiCorp transacts with its equity investees, Bridger Coal and Trapper Mining Inc. During the years ended December 31, 2012, 2011 and 2010, PacifiCorp charged Bridger Coal $1 million, $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 $6 million and $3 million as of December 31, 2012 and 2011, respectively. Services provided by equity investees and charged to PacifiCorp primarily relate to coal purchases. During the years ended December 31, 2012, 2011 and 2010, coal purchases from PacifiCorp's equity investees totaled $144 million, $126 million and $141 million, respectively. Payables to PacifiCorp's equity investees were $18 million and $28 million as of December 31, 2012 and 2011, respectively.

(19) Supplemental Cash Flow Disclosures

The summary of supplemental cash flow disclosures as of and for the years ended December 31 is as follows (in millions):

	2012	2011	2010
Interest paid, net of amounts capitalized	$ 331	$ 358	$ 331
Income taxes received, net	$ 205	$ 425	$ 395
Supplemental disclosure of non-cash investing and financing activities:			
Accounts payable related to property, plant and equipment additions	$ 167	$ 231	$ 216

(20) Unaudited Quarterly Operating Results (in millions)

	Three-Month Periods Ended			
	March 31, 2012	June 30, 2012	September 30, 2012	December 31, 2012
Operating revenue	$ 1,191	$ 1,153	$ 1,327	$ 1,211
Operating income	278	251	378	114
Net income	151	130	212	44

	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

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, 2012 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, 2012 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, 2012.

PacifiCorp
March 1, 2013

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, 2013, with respect to the current directors and executive officers of PacifiCorp:

Gregory E. Abel, 50, Chairman of the Board of Directors and Chief Executive Officer of PacifiCorp since 2006. Mr. Abel has been Chairman of the Board of Directors of MEHC since 2011, 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, 54, Director. Mr. Anderson has been a director of PacifiCorp since 2006 and Executive Vice President, General Counsel and Corporate Secretary of MEHC since 2012. Mr. Anderson was Senior Vice President, General Counsel and Corporate Secretary of MEHC from 2001 to 2012. 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, 47, President and Chief Executive Officer of PacifiCorp Energy and director of PacifiCorp since 2010; President of Kern River Gas Transmission Company ("Kern River"), an indirect subsidiary of MEHC, from 2007 to 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, 61, 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, 46, Director. Mr. Goodman has been a director of PacifiCorp since 2006 and Executive Vice President and Chief Financial Officer of MEHC since 2012. Mr. Goodman was Senior Vice President and Chief Financial Officer of MEHC from 1999 to 2012. 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, 43, Senior Vice President, Transmission and System Operations of PacifiCorp since 2012; director of PacifiCorp since 2007; Vice President and General Counsel of Pacific Power from 2007 to 2012; 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, 57, 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, 51, 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, 49, 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, 61, 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, 2012, 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, 2012 (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 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, among which are customer service, operational excellence, financial strength, employee commitment and safety, environmental respect and regulatory integrity, which we believe contribute to our long-term success.

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 2012, base salaries for all NEOs, other than Mr. Abel, increased on average by 3.6% effective December 26, 2011.

Short-Term Incentive Compensation

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

Annual Incentive Plan

Under our Annual Incentive Plan, or AIP, all NEOs, other than Mr. Abel, are eligible to earn an annual discretionary cash incentive award, which is determined on a subjective basis 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 annual incentive 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 2012. 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 2012.

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 2012, 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 various investment alternatives 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]	2012	$ —	$ —	$ —	$ —	$ —
Chairman and	2011	—	—	—	—	—
Chief Executive Officer	2010	—	—	—	—	—
A. Richard Walje	2012	368,000	768,541	428,807	30,970	1,596,318
President and Chief Executive	2011	368,000	516,548	670,980	32,676	1,588,204
Officer, Rocky Mountain Power	2010	357,150	721,364	548,195	35,096	1,661,805
R. Patrick Reiten	2012	300,000	996,621	—	24,900	1,321,521
President and Chief Executive	2011	291,528	747,678	650	23,643	1,063,499
Officer, Pacific Power	2010	265,740	828,466	445	24,301	1,118,952
Micheal G. Dunn	2012	300,000	677,088	12,725	27,782	1,017,595
President and Chief Executive	2011	278,820	463,169	13,856	26,500	782,345
Officer, PacifiCorp Energy	2010	230,114	355,000	12,925	24,638	622,677
Douglas K. Stuver	2012	244,055	370,172	15,179	29,953	659,359
Senior Vice President and	2011	239,269	269,216	11,010	31,971	551,466
Chief Financial Officer	2010	233,525	268,455	8,014	34,460	544,454

(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. The breakout for 2012 is as follows:

		LTIP [a]		
	AIP	Vested Awards	Vested Earnings	Total
A. Richard Walje	$ 242,000	$ 386,516	$ 140,025	$ 526,541
R. Patrick Reiten	310,000	467,400	219,221	686,621
Micheal G. Dunn	310,000	310,000	57,088	367,088
Douglas K. Stuver	120,000	177,550	72,622	250,172

(a) The LTIP vested awards and vested earnings columns exclude any amounts related to Mr. Dunn's awards granted prior to his transfer 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 2012, 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, 2012. Mr. Reiten had a decrease in the actuarial present value of his defined benefit plan amount; therefore no compensation is shown in the table. No participant in our nonqualified deferred compensation plans earned "above market" or "preferential" earnings on amounts deferred.

(3) Amounts primarily consist of PacifiCorp K Plus 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 $30,063; Mr. Reiten - 401(k) contributions of $24,750; Mr. Dunn - 401(k) contributions of $12,250 and DCP contributions of $15,382; and Mr. Stuver - 401(k) contributions of $29,804.

(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, 2012 (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, 2012:

Name	Plan name	Number of years of credited service	Present value of accumulated benefits (1)
Gregory E. Abel	Retirement	n/a	n/a
A. Richard Walje	SERP	27 years	$ 3,488,229
	Retirement	23 years	1,151,425
R. Patrick Reiten	Retirement	2 years	16,033
Micheal G. Dunn (2)	Retirement	3 years	39,506
Douglas K. Stuver	Retirement	5 years	111,943

(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, 2012, 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 4.05%; an expected retirement age of 60; and postretirement mortality using the tables prescribed by Internal Revenue Code Section 430(h)(3)(A) separated by annuitants and non-annuitants. The present value assumptions used in calculating the present value of accumulated benefits for the Retirement Plan were as follows: a discount rate of 4.05%; an expected retirement age of 65; postretirement mortality using the tables prescribed by Internal Revenue Code Section 430(h)(3)(A) separated by annuitants and non-annuitants; a lump sum interest rate of 4.05%; and lump sum mortality using the Internal Revenue Code Section 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 and has reached age 60. 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 his benefit based on a hypothetical account balance assuming Mr. Walje continues to receive interest credits under the Retirement Plan.

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. Interest is also credited to each participant's account. Employees who were age 40 or older as of May 31, 2007 received certain additional transition pay credits for five years from the effective date of the plan restatement.

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 nonqualified deferred compensation plan accounts held by each of our NEOs as of December 31, 2012:

Name	Executive contributions in 2012 (1)	Registrant contributions in 2012 (2)	Aggregate earnings/(losses) in 2012	Aggregate withdrawals/ distributions (3)	Aggregate balance as of December 31, 2012 (4)
Gregory E. Abel	$ —	$ —	$ —	$ —	$ —
A. Richard Walje	310,642	—	175,428	1,065,068	1,392,775
R. Patrick Reiten	—	—	39,889	—	388,202
Micheal G. Dunn	31,000	15,382	7,507	—	108,789
Douglas K. Stuver	—	—	914	—	7,994

(1) The Executive contribution amount shown for Mr. Dunn and $78,900 of the amount shown for Mr. Walje are included in the 2012 total compensation reported for them in the Summary Compensation Table and are not additional earned compensation. In addition, the Executive contribution amount shown for Mr. Walje includes $231,742 of his 2008 LTIP award which was deferred in 2012. Of this amount, $64,578 is included in the 2012 total compensation reported for him in the Summary Compensation Table and is not additional earned compensation. The remaining amount was earned prior to 2012.

(2) The Registrant contribution amount shown for Mr. Dunn is included in the 2012 total compensation reported for him in the Summary Compensation Table and is not additional earned compensation. The amount was earned in 2012 but not contributed into the DCP until 2013.

(3) Mr. Walje's aggregate withdrawals/distributions include a distribution in the amount of $1,054,017 for which he was not the recipient.

(4) The aggregate balance as of December 31, 2012 shown for Messrs. Walje and Dunn includes $30,870 and $28,857, respectively, of compensation previously reported in 2011 in the Summary Compensation Table, and for Messrs. Walje, Reiten, Dunn and Stuver includes $98,496, $101,749, $26,208 and $1,960, respectively, of compensation previously reported in 2010 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 various investment alternatives 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, 2012 (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, 2012, 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	—	141,961
Death and Disability	896,692	141,961
R. Patrick Reiten:		
Retirement, Voluntary and Involuntary With or Without Cause	—	3,152
Death and Disability	1,090,755	3,152
Micheal G. Dunn:		
Retirement, Voluntary and Involuntary With or Without Cause	—	9,004
Death and Disability	998,697	9,004
Douglas K. Stuver:		
Retirement, Voluntary and Involuntary With or Without Cause	—	4,674
Death and Disability	401,818	4,674

(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. The SERP termination scenario calculations are based on single life annuity.

Director Compensation Table

All of our directors serving in 2012 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. Please refer to MEHC's Annual Report on Form 10-K for the year ended December 31, 2012 (File No. 001-14881) for information about Messrs. Anderson and Goodman.

Name	Change in Pension Value and Nonqualified Deferred Compensation Earnings (1)	All Other Compensation (2)	Total
Douglas L. Anderson	$ —	$ —	$ —
Brent E. Gale	21,465	901,312	922,777
Patrick J. Goodman	—	—	—
Natalie L. Hocken	15,786	704,932	720,718
Mark C. Moench	17,968	486,142	504,110

(1) Amounts 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 related pension disclosures included in our Notes to the Consolidated Financial Statements in Item 8 of this Form 10-K and are as of December 31, 2012. No participant in our nonqualified deferred compensation plans earned "above market" or "preferential" earnings on amounts deferred.

(2) Amounts shown for the year ended December 31, 2012 that are required to be quantified are as follows:

(i) Base salary in the amounts of $292,750 for Mr. Gale, $198,533 for Ms. Hocken and $228,225 for Mr. Moench.

(ii) Contributions to our 401(k) Plan of $9,000 for Mr. Gale, $27,985 for Ms. Hocken and $12,032 for Mr. Moench.

(iii) Life insurance premium paid by us on behalf of Mr. Gale in the amount of $15,540.

(iv) Annual cash incentive awards earned pursuant to the AIP for our directors, the vesting of LTIP awards and associated vested earnings for Mr. Gale, Ms. Hocken and Mr. Moench. The breakout of AIP and LTIP awards for 2012 is as follows:

		LTIP		
	AIP	Vested Awards	Vested Earnings	Total
Brent E. Gale	$ 170,000	$ 262,977	$ 150,895	$ 413,872
Natalie L. Hocken	175,000	209,705	93,559	303,264
Mark C. Moench	98,000	121,027	26,707	147,734

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 MidAmerican Energy Holdings Company, or MEHC. Our common stock is indirectly owned by MEHC, 666 Grand Avenue, Suite 500, Des Moines, Iowa 50309-2580. MEHC is a consolidated subsidiary of Berkshire Hathaway that, as of January 31, 2013, 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 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, 2013:

	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	—	—	1	*	—	—
R. Patrick Reiten	—	—	—	—	—	—
Douglas K. Stuver	—	—	—	—	—	—
A. Richard Walje	—	—	—	—	—	—
All executive officers and directors as a group (10 persons)	595,940	0.8%	14	*	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, 2013, Mr. Abel would be entitled to exchange his shares of MEHC common stock for either 1,185 shares of Berkshire Hathaway Class A stock or 1,782,963 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's 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 MidAmerican Energy Holdings Company, or 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 Limited, and their respective affiliates (collectively, the "Deloitte Entities") for each of the last two years (in millions):

	2012	2011
Audit fees[1]	$ 1.5	$ 1.4
Audit-related fees[2]	0.3	0.3
Tax fees[3]	—	—
All other fees	—	—
Total	$ 1.8	$ 1.7

(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 1st day of March 2013.

PACIFICORP

/s/ Douglas K. Stuver

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

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

Signature	Title	Date
/s/ Gregory E. Abel Gregory E. Abel	Chairman of the Board of Directors and Chief Executive Officer (principal executive officer)	March 1, 2013
/s/ Douglas K. Stuver Douglas K. Stuver	Senior Vice President and Chief Financial Officer (principal financial and accounting officer)	March 1, 2013
/s/ Douglas L. Anderson Douglas L. Anderson	Director	March 1, 2013
/s/ Micheal G. Dunn Micheal G. Dunn	Director	March 1, 2013
/s/ Brent E. Gale Brent E. Gale	Director	March 1, 2013
/s/ Patrick J. Goodman Patrick J. Goodman	Director	March 1, 2013
/s/ Natalie L. Hocken Natalie L. Hocken	Director	March 1, 2013
/s/ Mark C. Moench Mark C. Moench	Director	March 1, 2013
/s/ R. Patrick Reiten R. Patrick Reiten	Director	March 1, 2013
/s/ A. Richard Walje A. Richard Walje	Director	March 1, 2013

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, 2005, filed May 27, 2005, 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	Period or 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*	$600,000,000 Credit Agreement, dated as of June 28, 2012, among PacifiCorp, as Borrower, the banks, financial institutions and other institutional lenders, as Initial Lenders, JPMorgan Chase Bank, N.A., as Administrative Agent and Swingline Lender, and the LC Issuing Banks. (Exhibit 10.1, Quarterly Report on Form 10-Q, filed August 3, 2012, 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 7, 2006, File No. 1-5152).
10.8*	Second Amendment dated as of January 6, 2012, amending the 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 10.11, Annual Report on Form 10-K, for the year ended December 31, 2011, filed February 27, 2012, File No. 1-5152).
10.9*	First Amendment dated as of April 15, 2009, amending the 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 (Exhibit 10.10, Annual Report on Form 10-K, for the year ended December 31, 2009, filed March 1, 2010, File No. 1-5152).
10.11†	Amendment No. 2 to the PacifiCorp Executive Voluntary Deferred Compensation Plan dated October 16, 2012.
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	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, 2012 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 Comprehensive Income, (iv) the Consolidated Statements of Changes in Equity, (v) the Consolidated Statements of Cash Flows and (vi) the Notes to Consolidated Financial Statements, tagged in summary and in detail.

*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, 2012 and incorporated by reference herein.

Base salary for named executive officers and employee directors for PacifiCorp's fiscal year ending December 31, 2013 (excluding Mr. Abel) is shown in the following table:

Name and Title	Base Salary
Douglas K. Stuver Senior Vice President and Chief Financial Officer	$ 246,495
A. Richard Walje President and Chief Executive Officer, Rocky Mountain Power	372,000
R. Patrick Reiten President and Chief Executive Officer, Pacific Power	310,000
Micheal G. Dunn President and Chief Executive Officer, PacifiCorp Energy	310,000
Brent E. Gale Director	300,000
Natalie L. Hocken Director	225,000
Mark C. Moench Director	233,360

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.

AMENDMENT NO. 2
TO THE
PACIFICORP
EXECUTIVE VOLUNTARY DEFERRED COMPENSATION PLAN

This Amendment No. 2 to the PacifiCorp Executive Voluntary Deferred Compensation Plan ("Plan") shall be effective as of January 1, 2013.

The purpose of this Amendment is to provide that members of the Advisory Boards (as defined in Section 1.18 the Plan prior to the adoption of this Amendment) are no longer eligible to participate in the Plan (no individual has participated in the past as an Advisory Board member).

1. Section 1.07, definition of "Compensation", is hereby amended by substituting the following in place thereof:

   "1.07 **'Compensation'** means Base Salary, performance awards and annual incentive bonuses (other than Employer long term incentive awards). Inclusion of any other forms of compensation is subject to approval by the Employer."

2. Section 1.18, definition of "Participant", is hereby amended by substituting the following in place thereof:

   "1.18 **'Participant'** means an Employee of the Employer who has met the eligibility requirements of Section 2.01 and who has accrued a benefit under the Plan."

3. Section 2.01, entitled "Participant Designated", is hereby amended by substituting the following in place thereof:

   "2.01 Participant Designated. The Chairman of the Board of Directors of the Employer shall designate and approve the Employees who are eligible to participate in the Plan, such designation to be either by name, job title or other classification. The Chairman may also notify any Participant that he or she is no longer eligible to make future deferrals into the Plan. Such termination of eligibility shall be effective for Compensation earned after December 31 following such written notification to the individual. However, until final distribution has been made to such person from his or her Accounts, for all other purposes under the Plan, the person shall still be considered a Participant."

IN WITNESS WHEREOF, PacifiCorp has caused this instrument to be signed by its duly authorized officer on this 16th day of October, 2012.

PACIFICORP

By: /s/ Gregory E. Abel

Gregory E. Abel

Chairman

EXHIBIT 12.1

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

	Years Ended December 31,				
	2012	2011	2010	2009	2008
Earnings Available for Fixed Charges:					
Income from continuing operations before income tax expense	$ 734	$ 768	$ 777	$ 784	$ 703
Add:					
Fixed charges	385	397	392	398	349
Deduct:					
Net income attributable to noncontrolling interest in subsidiary that has not incurred fixed charges	—	—	—	(8)	(7)
Total earnings available for fixed charges	$ 1,119	$ 1,165	$ 1,169	$ 1,174	$ 1,045
Fixed Charges:					
Interest expense	$ 380	$ 392	$ 387	$ 394	$ 343
Estimated interest portion of rentals charged to expense	5	5	5	4	6
Total fixed charges	$ 385	$ 397	$ 392	$ 398	$ 349
Ratio of Earnings to Fixed Charges	2.9x	2.9x	3.0x	2.9x	3.0x

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,				
	2012	2011	2010	2009	2008
Earnings Available for Fixed Charges:					
Income from continuing operations before income tax expense	$ 734	$ 768	$ 777	$ 784	$ 703
Add:					
Fixed charges	385	397	392	398	349
Deduct:					
Net income attributable to noncontrolling interest in subsidiary that has not incurred fixed charges	—	—	—	(8)	(7)
Total earnings available for fixed charges	$ 1,119	$ 1,165	$ 1,169	$ 1,174	$ 1,045
Fixed Charges and Preferred Stock Dividends:					
Interest expense	$ 380	$ 392	$ 387	$ 394	$ 343
Estimated interest portion of rentals charged to expense	5	5	5	4	6
Total fixed charges	385	397	392	398	349
Preferred stock dividends (1)	3	3	3	3	3
Total fixed charges and preferred stock dividends	$ 388	$ 400	$ 395	$ 401	$ 352
Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends	2.9x	2.9x	3.0x	2.9x	3.0x

(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 March 1, 2013, 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, 2012.

/s/ Deloitte & Touche LLP
Deloitte & Touche LLP

Portland, Oregon
March 1, 2013

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: March 1, 2013

/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: March 1, 2013

/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, 2012 (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 results of operations of the Company.

Date: March 1, 2013

/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, 2012 (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 results of operations of the Company.

Date: March 1, 2013

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

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, 2012 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, 2012. There were no mining-related fatalities during the year ended December 31, 2012. PacifiCorp has not received any notice of a pattern, or notice of the potential to have a pattern, of violations of mandatory health or safety standards that are of such nature as could have significantly and substantially contributed to the cause and effect of coal or other mine health or safety hazards under Section 104(e) of the Mine Safety Act during the year ended December 31, 2012.

	Mine Safety Act						Legal Actions		
Mining Facilities	Section 104 Significant and Substantial Citations(1)	Section 104(b) Orders(2)	Section 104(d) Citations/ Orders(3)	Section 110(b)(2) Violations(4)	Section 107(a) Imminent Danger Orders(5)	Total Value of Proposed MSHA Assessments (in thousands)	Pending as of Last Day of Period(6)	Instituted During Period	Resolved During Period
Deer Creek	12	—	1	—	—	$ 38	5	5	12
Bridger (surface)	5	—	—	—	—	6	2	2	4
Bridger (underground)	44	—	8	—	1	173	26	21	12
Cottonwood Preparatory Plant	—	—	—	—	—	—	—	—	—
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.

(3) For an alleged unwarrantable failure (i.e., aggravated conduct constituting more than ordinary negligence) to comply with a mandatory health or safety standard. Two of the Section 104(d) citations/orders included in the table were subsequently modified by MSHA to be Section 104(a) Significant and Substantial citations. Additionally, three of the Section 104(d) citations/orders included in the table were subsequently settled with the Federal Mine Safety and Health Review Commission. Of those, one was reduced to a Section 104(a) Significant and Substantial citation and two were reduced to Section 104(a) Non-Significant and Substantial citations. PacifiCorp is contesting or intends to contest three of the remaining Section 104(d) citations/ orders.

(4) For alleged flagrant violations (i.e., reckless or repeated failure to make reasonable efforts to eliminate a known violation of a mandatory health or safety standard that substantially and proximately caused, or reasonably could have been expected to cause, death or serious bodily injury).

(5) For the existence of any condition or practice in a coal or other mine which could reasonably be expected to cause death or serious physical harm before such condition or practice can be abated. On March 20, 2012, Bridger received an imminent danger order under Section 107(a) of the Mine Safety Act at its underground mine located near Rock Springs, Wyoming. The order was reconsidered and subsequently vacated by MSHA.

(6) Amounts include contests of 29 proposed penalties under Subpart C and contests of four citations or orders under Subpart B of the Federal Mine Safety and Health Review Commission's procedural rules. The pending legal actions are not exclusive to citations, notices, orders and penalties assessed by MSHA during the reporting period.