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, 2014 2015 MAR 23 A 9:06

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: None

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 Berkshire Hathaway Energy Company, 666 Grand Avenue, Suite 500, Des Moines, Iowa 50309-2580. As of January 31, 2015, 357,060,915 shares of common stock were outstanding.

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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	
BHE	Berkshire Hathaway Energy Company
PacifiCorp	PacifiCorp and its subsidiaries
PPW Holdings	PPW Holdings LLC, a wholly owned subsidiary of BHE and PacifiCorp's direct parent company
Berkshire Hathaway	Berkshire Hathaway Inc. and its subsidiaries
Lake Side 2	631-megawatt combined-cycle combustion turbine natural gas-fueled generating facility
Certain Industry Terms	
AFUDC	Allowance for Funds Used During Construction
CPUC	California Public Utilities Commission
Dodd-Frank Reform Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
DSM	Demand-side Management
EBA	Energy Balancing Account
ECAC	Energy Cost Adjustment Clause
ECAM	Energy Cost Adjustment Mechanism
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gases
GWh	Gigawatt Hours
IPUC	Idaho Public Utilities Commission
kV	Kilovolt
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
REC	Renewable Energy Credit
RPS	Renewable Portfolio Standards
RRA	Renewable Energy Credit and Sulfur Dioxide Revenue Adjustment Mechanism
SEC	United States Securities and Exchange Commission
TAM	Transition Adjustment Mechanism
UPSC	Utah Public Service Commission
WECC	Western Electricity Coordinating Council
WPSC	Wyoming Public Service Commission
WUTC	Washington Utilities and Transportation Commission

Forward-Looking Statements

This report contains statements that do not directly or exclusively relate to historical facts. These statements are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, 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, and compliance with, laws and regulations, including reliability and safety standards, 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 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, new technologies and various conservation, energy efficiency and distributed generation measures and programs, 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;
- changes in prices, availability and demand for wholesale electricity, coal, natural gas, other fuel sources and fuel transportation that could have a significant impact on generating capacity and energy costs;
- 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;
- the effects of catastrophic and other unforeseen events, which may be caused by factors beyond PacifiCorp's control or by a breakdown or failure of PacifiCorp's operating assets, including storms, floods, fires, earthquakes, explosions, landslides, mining accidents, litigation, wars, terrorism and embargoes;
- 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 certain 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 certain contracts;
- the impact of inflation on costs and PacifiCorp's ability to recover such costs in rates;
- increases in employee healthcare costs, including the implementation of the Affordable Care Act;

- 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; 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 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 11,136 MW. PacifiCorp owns, or has interests in, electric transmission and distribution assets, and transmits electricity through approximately 16,400 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 customer 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 BHE, a holding company based in Des Moines, Iowa that owns subsidiaries principally engaged in energy businesses. BHE is a consolidated subsidiary of Berkshire Hathaway. BHE 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.

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 electricity supply and through demand response and energy efficiency programs. During 2011, PacifiCorp began construction of Lake Side 2, which was placed in-service in May 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 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. In 2014, PacifiCorp and the California Independent System Operator Corporation ("California ISO") implemented an energy imbalance market ("EIM"), which is expected to reduce costs to serve customers through more efficient dispatch of a larger and more diverse pool of resources, more effectively integrate renewables and enhance reliability.

Employees

As of December 31, 2014, PacifiCorp had approximately 5,900 employees, of which approximately 3,400 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 ("UMWA").

Retail Service Territories

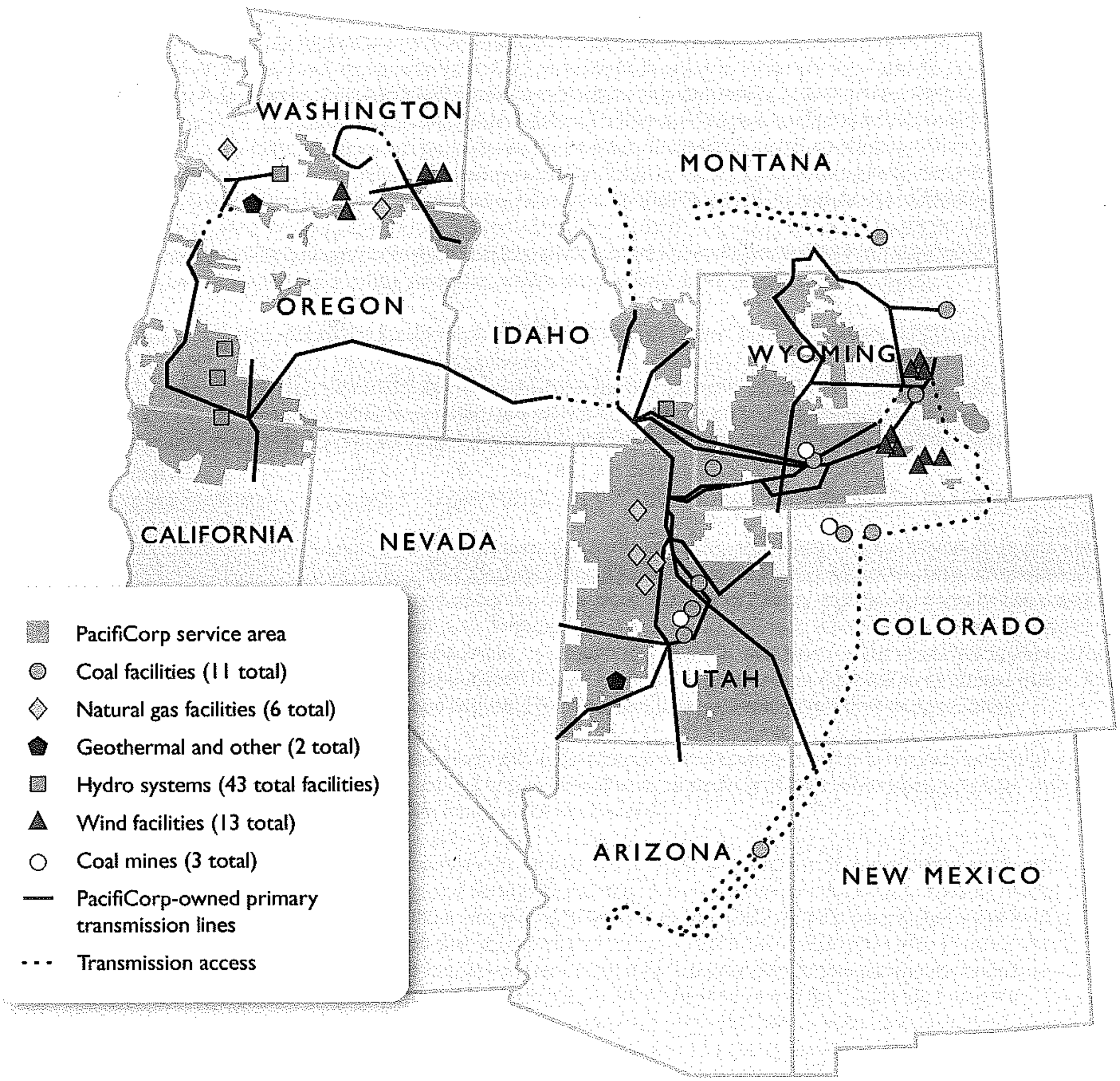
PacifiCorp's combined service territory covers approximately 143,000 square miles and includes diverse regional economies. No single segment of the economy dominates the service territory, which helps mitigate PacifiCorp's exposure to economic fluctuations. In the eastern portion of the service territory, 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 28 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:

	2014		2013		2012	
Utah	24,105	44 %	24,510	44 %	23,930	44 %
Oregon	12,959	24	13,090	24	12,779	23
Wyoming	9,568	17	9,554	17	9,498	17
Washington	4,118	8	4,093	7	4,042	7
Idaho	3,495	6	3,621	7	3,518	7
California	754	1	795	1	782	2
	54,999	100 %	55,663	100 %	54,549	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, 2014. PacifiCorp's generating facilities are interconnected through PacifiCorp's own transmission lines or by contract through transmission lines owned by others.



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:

	2014		2013		2012	
GWh sold:						
Residential	15,568	24%	16,339	25%	15,968	24%
Commercial	17,073	26	17,057	26	16,829	25
Industrial and irrigation	21,934	34	21,832	33	21,317	32
Other	424	—	435	1	435	1
Total retail	54,999	84	55,663	85	54,549	82
Wholesale	10,270	16	10,206	15	11,870	18
Total GWh sold	65,269	100%	65,869	100%	66,419	100%
Average number of retail customers (in thousands):						
Residential	1,546	87%	1,522	86%	1,504	86%
Commercial	200	11	208	12	212	12
Industrial and irrigation	33	2	34	2	34	2
Other	4	—	3	—	4	—
Total	1,783	100%	1,767	100%	1,754	100%
Retail customers:						
Average usage per customer (kilowatt hours)	30,846		31,501		31,100	
Average revenue per customer	$ 2,645		$ 2,627		$ 2,455	
Revenue per kilowatt hour	8.6¢		8.3¢		7.9¢	

Customer Usage and Seasonality

Changes in economic and weather conditions, as well as various conservation, energy efficiency and customer self-generation measures and programs, impact customer usage.

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 2014, PacifiCorp's peak demand was 10,314 MW in the summer and 8,870 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 and may include forwards, options, swaps and other agreements. Refer to "General Regulation" in Item 1 of this Form 10-K for a discussion of energy cost recovery by jurisdiction and 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, 2014:

Generating Facility	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	2,123	1,415
Hunter Nos. 1, 2 and 3	Castle Dale, UT	Coal	1978-1983	1,363	1,158
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	760	760
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	332	266
Carbon Nos. 1 and 2 [3]	Castle Gate, UT	Coal	1954-1957	172	172
Craig Nos. 1 and 2	Craig, CO	Coal	1979-1980	855	165
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
				9,522	6,153
NATURAL GAS:					
Lake Side 2	Vineyard, UT	Natural gas/steam	2014	631	631
Lake Side	Vineyard, UT	Natural gas/steam	2007	546	546
Currant Creek	Mona, UT	Natural gas/steam	2005-2006	524	524
Chehalis	Chehalis, WA	Natural gas/steam	2003	477	477
Hermiston	Hermiston, OR	Natural gas/steam	1996	461	231
Gadsby Steam	Salt Lake City, UT	Natural gas	1951-1955	238	238
Gadsby Peakers	Salt Lake City, UT	Natural gas	2002	119	119
				2,996	2,766
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	100	100
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
				1,039	1,030
OTHER: [4]					
Blundell	Milford, UT	Geothermal	1984, 2007	32	32
Camas Co-Gen	Camas, WA	Black liquor	1996	10	10
				42	42
Total Available Generating Capacity				14,744	11,136

(1) Facility Net Capacity represents the lesser of nominal ratings or any limitations under applicable interconnection, power purchase or other agreements for intermittent resources and the total net dependable capability available during summer conditions for all other units. An intermittent resource's nominal rating is the manufacturer's contractually specified capability under specified conditions. Net Owned Capacity indicates PacifiCorp's ownership of Facility Net Capacity.

(2) PacifiCorp currently plans to convert Naughton Unit No. 3 (330 MW) to a natural gas-fueled unit in 2018. Refer to "Environmental Laws and Regulations" in Item 7 of this Form 10-K for further discussion.

(3) PacifiCorp plans to retire Carbon Unit Nos. 1 and 2 ("Carbon Facility") in April 2015. Refer to "Environmental Laws and Regulations" in Item 7 of this Form 10-K for further discussion.

(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. In 2013, PacifiCorp began the relicensing process for Prospect No. 3 pursuant to the FERC Integrated Licensing Process.

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

	2014	2013	2012
Coal	60 %	62 %	60 %
Natural gas	16	12	10
Hydroelectric[1]	5	4	6
Wind and other[1]	5	5	5
Total energy generated	86	83	81
Energy purchased - short-term contracts and other	6	9	12
Energy purchased - long-term contracts (renewable)[1]	5	5	5
Energy purchased - long-term contracts (non-renewable)	3	3	2
	100 %	100 %	100 %

(1) All or some of the renewable energy attributes associated with generation from these generating facilities and purchases may be: (a) used in future years to comply with RPS or other regulatory requirements, (b) sold to third parties in the form of RECs or other environmental commodities, or (c) excluded from energy purchased.

Coal

PacifiCorp has interests in coal mines that support its coal-fueled generating facilities and operates the Bridger surface and Bridger underground coal mines, as well as the Deer Creek underground coal mine discussed below that has historically served the Huntington, Hunter and Carbon generating facilities. These mines supplied 27%, 31% and 30% of PacifiCorp's total coal requirements during the years ended December 31, 2014, 2013 and 2012, 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.

Due to coal quality issues and rising costs, PacifiCorp believes the Deer Creek coal reserves are no longer able to be economically mined. As a result, PacifiCorp intends to permanently close the Deer Creek mine, and in the second quarter of 2015, sell the Cottonwood Preparatory Plant to a third party. PacifiCorp also intends to enter into a long-term coal supply agreement and amend an existing long-term coal supply agreement. Refer to "Regulatory Matters" in Item 7 of this Form 10-K for further discussion of these proposed transactions, including pending regulatory approvals.

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, 2014, 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	35	(1)
Bridger	Rock Springs, WY	Jim Bridger	Underground	35	(1)
Trapper	Craig, CO	Craig	Surface	6	(2)
				76	

(1) These coal reserves are leased and mined by Bridger Coal Company, a joint venture between Pacific Minerals, Inc. and a subsidiary of Idaho Power Company. Pacific Minerals, Inc., 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 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 during the coal uncovering process. Once the overburden and topsoil have been replaced, vegetation is re-established, and other improvements are made that have local community and environmental benefits.

For underground mine operations, a longwall is used as a mechanical shearer to extract coal from long rectangular blocks of medium to thick seams that are initially developed by the use of continuous miner machines. In longwall mining, 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 Fuels, LLC ("Fossil Rock"), a wholly owned subsidiary of PacifiCorp, acquired the Cottonwood coal reserve lease in Emery County Utah, which contains an estimated 47 million tons of recoverable coal. Subject to the regulatory approvals described in "Regulatory Matters" in Item 7 of this Form 10-K, PacifiCorp intends to sell the rights to the Fossil Rock coal reserves to a third party in the second quarter of 2015.

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 at fixed or indexed market prices. 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. A portion of this portfolio is licensed under the Oregon Hydroelectric Act. For further discussion of PacifiCorp's hydroelectric relicensing activities, including updated information regarding the Klamath River hydroelectric system, refer to Note 13 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Wind and Other Renewable Resources

PacifiCorp has pursued 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 and require little or no fossil fuel. 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 purchase commitments with its retail load and wholesale sales obligations. PacifiCorp may also purchase electricity in the wholesale markets when it is more economical than generating electricity from its own facilities and may sell surplus electricity in the wholesale markets when it can do so economically. When prudent, PacifiCorp enters into financial swap contracts and forward electricity sales and purchases for physical delivery at fixed prices to reduce its exposure to electricity price volatility.

Transmission and Distribution

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

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

As of December 31, 2014, PacifiCorp owned, or participated in, a transmission system consisting of approximately:

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

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

PacifiCorp's transmission and distribution system included approximately 63,000 miles of distribution lines and 900 substations as of December 31, 2014. 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 placed in-service in 2010; (b) the 100-mile high-voltage transmission line between the Mona substation in central Utah and the Oquirrh substation in the Salt Lake Valley 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 May 2015; and (d) other segments that are expected to be placed in-service in future years, depending on load growth, 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, 2014, $1.8 billion had been spent and $1.3 billion, 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 title holder of record; 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.

Energy Imbalance Market

In February 2013, PacifiCorp and the California ISO announced their plans to implement an EIM, which went live in November 2014. The EIM expands the real-time component of the California ISO market to optimize and balance electricity supply and demand every five minutes across the entire PacifiCorp and California ISO six-state footprint. The EIM is voluntary and available to all balancing authorities in the Western United States. EIM market participants submit bids to the California ISO market operator before each hour for each generating resource they choose to be dispatched by the market. Each bid is comprised of a dispatchable operating range, ramp rate and prices across the operating range. The California ISO market operator uses sophisticated technology to select the least-cost resources to meet demand and send simultaneous dispatch signals to every participating generator across the six-state EIM footprint every five minutes. In addition to generation resource bids, the California ISO market operator also receives continuous real-time updates of transmission grid network, meteorological and load forecast information that it uses to optimize dispatch instructions. Outside the EIM footprint, utilities in the Western United States do not utilize comparable technology and are largely limited to transactions within the borders of their balancing authority area to balance supply and demand intra-hour using a combination of manual and automated dispatch. The EIM delivers customer benefits by leveraging automation and resource diversity to result in more efficient dispatch, more effective integration of renewables and improved situational awareness. Benefits to customers are expected to increase with renewable resource expansion and as more entities join the EIM bringing incremental diversity.

The EIM began operations in October 2014 with a 30-day transition period during which the California ISO and PacifiCorp enabled their systems to interact and produce results reflecting realistic market conditions, but without financially binding settlements or dispatch instructions. The EIM transitioned to a fully operational, financially binding market on November 1, 2014.

Future Generation, Conservation and Energy Efficiency

Integrated Resource Plan

As required by certain state regulations, PacifiCorp uses an Integrated Resource Plan ("IRP") to develop a long-term view of prudent future actions required to help ensure that PacifiCorp continues to provide reliable and cost-effective electric service to its customers 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 five states indicate whether the IRP meets the state commission's IRP standards and guidelines, a process referred to as "acknowledgment" in some states. In April 2013, PacifiCorp filed its 2013 IRP with the state commissions. The WPSC accepted the 2013 IRP into its files and the IPUC, the WUTC and the UPSC acknowledged the 2013 IRP. The OPUC acknowledged the 2013 IRP with exceptions and revisions to specific action items. PacifiCorp is currently developing its 2015 IRP that is expected to be filed in March 2015.

Requests for Proposals

PacifiCorp issues individual Requests for Proposals ("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.

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 2014, PacifiCorp spent $155 million on these DSM programs, resulting in an estimated 566,034 MWh of first-year energy savings and an estimated 312 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 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, operations and maintenance, depreciation and amortization 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 cost of service 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 in 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. In some jurisdictions, certain classes of customers may choose to purchase all or a portion of their energy from alternative energy suppliers, and in some jurisdictions retail customers can generate all or a portion of their own energy. Under Oregon law, PacifiCorp has the exclusive right and obligation to provide electricity distribution services to all residential and nonresidential customers within its allocated service territory; however, nonresidential customers have the right to choose an alternative provider of energy supply. 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. Also, PacifiCorp is evaluating how best to integrate distributed generation resources into its service and rate design, including considering such factors as maintaining high levels of customer safety and service reliability, minimizing adverse cost impacts and fairly allocating costs among all customers.

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. 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 for proceeds from the sale of RECs.
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.

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; construction and operation of hydroelectric facilities; utility holding companies; accounting and records retention; securities issuances; and other matters. 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 2013 and is currently pending before the FERC. Under the FERC's market-based rules, PacifiCorp must also file with the FERC a notice of change in status when there is a change in the conditions that the FERC relied upon in granting market-based rate authority. In January 2014, as supplemented in July 2014, PacifiCorp filed with the FERC a notification of change in status as a result of PacifiCorp's affiliation with NV Energy, Inc. and its subsidiaries following BHE's acquisition of NV Energy, Inc. and the addition of Lake Side 2. On December 9, 2014, the FERC issued an order requesting that the BHE subsidiaries having authority to sell power and energy at market-based rates, including PacifiCorp, show cause why their market-based rate authority remains just and reasonable following BHE's acquisition of NV Energy, Inc. This proceeding remains ongoing.

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 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.

In December 2011, PacifiCorp adopted a cost-based formula rate under its OATT for its transmission services. 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 formula rate results are subject to discovery and challenges by the FERC and intervenors. 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 operations, 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

The FERC licenses and regulates the operation of hydroelectric systems, including license compliance and dam safety programs. 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. Under the Federal Power Act, 17 dams associated with PacifiCorp's hydroelectric generating facilities licensed with the FERC are classified as "high hazard potential," meaning it is probable in the event of dam failure that loss of human life in the downstream population could occur. The FERC provides guidelines followed by PacifiCorp in developing public safety programs that consist of an owner's dam safety program and emergency action plans.

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. 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.

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 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 numerous risks and uncertainties, 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 which we currently deem immaterial may also impair our business operations.

We are subject to operating uncertainties and events beyond our control that impact the costs to operate, maintain, repair and replace utility systems, 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 our thermal, hydroelectric and other electricity generating facilities and related equipment, transmission and distribution lines or other equipment or processes, which could lead to catastrophic events; unscheduled outages; strikes, lockouts or other labor-related actions; shortages of qualified labor; transmission and distribution system constraints; terrorist activities or military or other actions, including 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, explosions, landslides, wars, terrorism, embargoes and mining accidents. A catastrophic event might result in injury or loss of life, extensive property damage or environmental or natural resource damages. For example, in the event of an uncontrolled release of water at one of our high hazard potential hydroelectric facilities, it is probable that loss of human life, disruption of lifeline facilities and property damage could occur in the downstream population and civil or other penalties could be imposed by the FERC. 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 subject to extensive federal, state and local legislation and regulation, including numerous environmental, health, safety, reliability 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 impose new or revised requirements or standards on our business.

We are required to comply with numerous federal, state and local laws and regulations as described in Item 1 of this Form 10-K that have broad application to our business and limit our ability to independently make and implement management decisions regarding, among other items, constructing, acquiring or disposing of operating assets; acquiring businesses; 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 followed in developing our safety and compliance programs and procedures and are implemented and enforced by federal, state and local regulatory agencies, such as, among others, the Occupational Safety and Health Administration, 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 existing or new laws and regulations could be prohibitively expensive or otherwise uneconomical. As a result, we could be required to shut down some facilities or materially 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 or failure to comply with the terms and conditions of the authorizations 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 new or stricter air quality standards; the implementation of energy efficiency mandates; the issuance of regulations governing 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 our 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 and certain activities are subject to regulatory review and approval, and the inability to recover costs or undertake certain activities 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 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.

States set 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, investment and capital structure 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. 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 jurisdiction 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, affiliate restrictions, 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. We are 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 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 include and may include in the future, among others, construction and other costs for new electricity generating facilities, transmission or distribution projects, environmental control and compliance systems and 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 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, could impact our planned capital expenditures and could adversely affect our consolidated financial results.

A significant sustained decrease in demand for electricity in the markets served by us would significantly decrease our operating revenue, could impact our planned capital expenditures 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 electricity generated or distributed through various conservation, energy efficiency and distributed generation 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 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 negatively 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, demand for electricity, 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 may not be 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 is rated investment grade by various rating agencies. We cannot assure that our long-term debt 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 have 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 or other actions by nations or 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 attacks, including cyberattacks. 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' or customers' financial condition deteriorates or they otherwise become unable to pay, it could have a significant adverse impact on our liquidity and 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, customers and contractors. 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.

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 and 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, discount rates, mortality assumptions, the interest rates used to measure required minimum funding levels, the funded status of the plans, changes in benefit design, tax deductibility and funding limits, 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 joint trustee and multiemployer plans to which we and our subsidiary contribute, respectively, are in underfunded positions. Furthermore, the funded status of the UMWA 1974 Pension Trust multiemployer plan to which our subsidiary contributes is considered critical, subjecting the plan to rehabilitation, including the previously issued funding improvement plan that is expected to require higher cash contributions in the future. To the extent we or our subsidiary withdraw from the multiemployer plans, we or our subsidiary may be subject to a significant withdrawal liability. 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. 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. Similarly, funds dedicated to Bridger Coal Company 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 could 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 available cash.

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 or to 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, such as those that 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.

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 material payments substantially in excess of established reserves or in terms that could require that we change business practices and procedures or divest ownership of assets. 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 have a material adverse effect on our consolidated financial results.

BHE could exercise control over us in a manner that would benefit BHE to the detriment of our creditors and preferred stockholders.

BHE, 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 BHE and our creditors and preferred stockholders, BHE could exercise its control in a manner that would benefit BHE to the detriment of our creditors and preferred stockholders.

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 or interest to all of the real property making up its respective facilities in all material respects.

Headquarters/Offices

PacifiCorp's corporate offices consist of approximately 700,000 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 2 million square feet of field office and warehouse space in various other locations in Utah, Oregon, Wyoming, Washington, Idaho and California. The field location square footage does not include offices located at PacifiCorp's 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.

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

BHE indirectly owns all of the shares of PacifiCorp's outstanding common stock. Therefore, there is no public market for PacifiCorp's common stock.

In 2014 and 2013, PacifiCorp declared and paid dividends of $725 million and $500 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 to Note 15 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Item 6. Selected Financial Data

The following table sets forth PacifiCorp's selected consolidated historical financial data, which should be read in conjunction with 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,				
	2014	2013	2012	2011	2010
Consolidated Statement of Operations Data:					
Operating revenue	$ 5,252	$ 5,147	$ 4,882	$ 4,586	$ 4,432
Operating income	1,300	1,264	1,021	1,084	1,036
Net income	698	682	537	555	566

	As of December 31,				
	2014	2013	2012	2011	2010
Consolidated Balance Sheet Data:					
Total assets	$ 22,267	$ 21,659	$ 21,728	$ 21,106	$ 20,146
Short-term debt	20	—	—	688	36
Current portion of long-term debt and capital lease obligations	134	238	267	19	588
Long-term debt and capital lease obligations, excluding current portion	6,919	6,639	6,594	6,194	5,813
Total shareholders' equity	7,756	7,787	7,644	7,312	7,311

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, 2014 was $698 million, an increase of $16 million, or 2%, compared to 2013. Net income increased primarily due to higher retail prices, lower purchased electricity, lower operations and maintenance expense as a result of current year insurance recoveries expected from a fire claim and related charges in 2013, and higher wholesale electricity revenue, partially offset by higher fuel costs, lower retail customer load, higher depreciation and amortization expense and lower net deferrals of incurred net power costs. Retail customer load decreased 1.2% for 2014 compared to 2013 primarily due to the impacts of milder weather on residential and commercial customers primarily in Utah and Oregon, partially offset by higher commercial and residential customer usage primarily in Utah, higher average number of residential customers and higher irrigation customer usage in Oregon. Energy generated increased 3% for 2014 compared to 2013 due to higher natural gas-fueled generation, including the addition of Lake Side 2, and higher hydroelectric generation, partially offset by lower coal-fueled generation. Wholesale electricity sales volumes increased 1% and purchased electricity volumes decreased 20%.

Net income for the year ended December 31, 2013 was $682 million, an increase of $145 million, or 27%, compared to 2012. Net income increased largely due to $87 million of lower net after-tax charges related to the USA Power litigation and certain fire and other damage claims. Excluding these charges, net income increased $58 million as compared to 2012 primarily due to higher retail prices, higher retail customer load and lower natural gas costs, partially offset by higher purchased electricity, lower REC revenue, higher coal costs, higher income tax expense and higher depreciation and amortization expense. Retail customer load increased 2.0% for 2013 compared to 2012 primarily due to the impacts of hotter weather in the third quarter and colder weather in the first and fourth quarters on residential and commercial customers, higher industrial customer usage and an increase in the average number of residential customers, partially offset by lower residential customer usage. Energy generated increased 2% for 2013 compared to 2012 due to higher coal- and natural gas-fueled generation, partially offset by lower hydroelectric generation from reduced inflows.

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.

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

	2014	2013	Change		2013	2012	Change	
Gross margin (in millions):								
Operating revenue	$ 5,252	$ 5,147	$ 105	2 %	$ 5,147	$ 4,882	$ 265	5 %
Energy costs	1,997	1,924	73	4	1,924	1,818	106	6
Gross margin	$ 3,255	$ 3,223	$ 32	1	$ 3,223	$ 3,064	$ 159	5
Sales (GWh):								
Residential	15,568	16,339	(771)	(5)%	16,339	15,968	371	2 %
Commercial	17,073	17,057	16	—	17,057	16,829	228	1
Industrial and irrigation	21,934	21,832	102	—	21,832	21,317	515	2
Other	424	435	(11)	(3)	435	435	—	—
Total retail	54,999	55,663	(664)	(1)	55,663	54,549	1,114	2
Wholesale	10,270	10,206	64	1	10,206	11,870	(1,664)	(14)
Total sales	65,269	65,869	(600)	(1)	65,869	66,419	(550)	(1)
Average number of retail customers (in thousands)	1,783	1,767	16	1 %	1,767	1,754	13	1 %
Average revenue per MWh:								
Retail	$ 85.73	$ 83.40	$ 2.33	3 %	$ 83.40	$ 78.93	$ 4.47	6 %
Wholesale	$ 33.94	$ 31.40	$ 2.54	8 %	$ 31.40	$ 27.59	$ 3.81	14 %
Sources of energy (GWh)(1):								
Coal	42,218	43,688	(1,470)	(3)%	43,688	42,457	1,231	3 %
Natural gas	10,881	8,176	2,705	33	8,176	7,233	943	13
Hydroelectric(2)	3,782	3,163	619	20	3,163	4,262	(1,099)	(26)
Wind and other(2)	3,318	3,353	(35)	(1)	3,353	3,319	34	1
Total energy generated	60,199	58,380	1,819	3	58,380	57,271	1,109	2
Energy purchased	9,817	12,243	(2,426)	(20)	12,243	13,777	(1,534)	(11)
Total	70,016	70,623	(607)	(1)	70,623	71,048	(425)	(1)
Average cost of energy per MWh:								
Energy generated(3)	$ 20.71	$ 19.19	$ 1.52	8 %	$ 19.19	$ 19.21	$ (0.02)	— %
Energy purchased	$ 58.56	$ 55.16	$ 3.40	6 %	$ 55.16	$ 41.92	$ 13.24	32 %

(1) GWh amounts are net of energy used by the related generating facilities.

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

(3) The average cost per MWh of energy generated includes the cost of fuel associated with the generating facilities and does not include other costs.

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

Gross margin increased $32 million, or 1%, for 2014 compared to 2013 primarily due to:

- $144 million of increases mainly from higher retail rates;
- $100 million of lower purchased electricity due to reduced volumes, partially offset by higher average market prices; and
- $28 million of higher wholesale electricity revenue primarily due to higher average market prices.

The increase in gross margin was partially offset by:

- $74 million of higher natural gas costs primarily due to increased generation, including the addition of Lake Side 2, partially offset by lower average unit costs;
- $71 million from a 1.2% decrease in retail customer load, with a 2.3% decrease due to the impacts of milder weather on residential and commercial customers primarily in Utah and Oregon, partially offset by a 1.1% higher customer usage consisting of higher commercial and residential customer usage primarily in Utah, higher average number of residential customers and higher irrigation customer usage in Oregon;
- $52 million of higher coal costs due to higher average unit costs and costs associated with the Utah mine disposition discussed in "Regulatory Matters," partially offset by reduced volumes;
- $34 million of lower net deferrals of incurred net power costs in accordance with established adjustment mechanisms; and
- $14 million of higher transmission expense.

Operations and maintenance decreased $57 million, or 5%, for 2014 compared to 2013 due to current year insurance recoveries expected from the Sanpete County, Utah rangeland fire and related charges in 2013. The Sanpete County, Utah rangeland fire is discussed in Note 13 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Depreciation and amortization increased $51 million, or 8%, for 2014 compared to 2013 due to the impact of PacifiCorp's depreciation rate study effective January 1, 2014 of $35 million and higher plant in-service, including Lake Side 2.

Allowance for borrowed and equity funds decreased $10 million, or 12%, for 2014 compared to 2013 primarily due to lower qualified construction work-in-progress as Lake Side 2 was placed in-service in May 2014.

Income tax expense increased $12 million, or 4%, for 2014 compared to 2013 and the effective tax rate was 31% and 30% for 2014 and 2013, respectively. The increase in income tax expense was primarily due to higher pre-tax book income.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

Gross margin increased $159 million, or 5%, for 2013 compared to 2012 primarily due to:

- $259 million of increases mainly from higher retail rates, including a $17 million reduction in 2012 due to a one-time credit provided to Oregon customers for PacifiCorp's investments in certain emissions control equipment at its coal-fueled generating facilities;
- $78 million of increases from higher retail customer load due to the impacts of hotter weather in the third quarter of 2013 and colder weather in the first and fourth quarters of 2013 on residential and commercial customers, higher industrial customer usage primarily in the eastern portion of PacifiCorp's service territory and an increase in the average number of residential customers, partially offset by lower residential customer usage;
- $41 million of lower natural gas costs due to lower average unit costs, partially offset by increased generation; and
- $8 million of higher net deferrals of incurred net power costs in accordance with established adjustment mechanisms.

The increase in gross margin was partially offset by:

- $98 million of higher purchased electricity due to higher average market prices and lower gains on electricity swaps, partially offset by decreased volumes;
- $74 million of lower REC revenue;
- $61 million of higher coal costs due to higher unit costs and increased generation; and
- $7 million of lower wholesale electricity revenue due to lower volumes, partially offset by higher average market prices.

Operations and maintenance decreased $128 million, or 10%, for 2013 compared to 2012 due to $165 million of charges in 2012 related to the USA Power litigation and certain fire and other damage claims, partially offset by $25 million of additional charges for certain fire and other damage claims in 2013. 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 $35 million, or 5%, for 2013 compared to 2012 primarily due to higher plant in-service and accelerated depreciation rates for Oregon's share of the Carbon Facility expected to be retired in April 2015.

Taxes, other than income taxes increased $9 million, or 6%, for 2013 compared to 2012 primarily due to increased property taxes from higher plant in-service.

Income tax expense increased $100 million, or 51%, for 2013 compared to 2012 and the effective tax rate was 30% and 27% for 2013 and 2012, respectively. The increase in PacifiCorp's effective tax rate was primarily due to higher pre-tax book income, which reduced the effective tax rate impact of income tax benefits, primarily production tax credits.

Liquidity and Capital Resources

As of December 31, 2014, PacifiCorp's total net liquidity was $805 million as follows (in millions):

Cash and cash equivalents	$ 23
Credit facilities[1]	1,200
Less:	
Short-term debt	(20)
Letters of credit and tax-exempt bond support	(398)
Net credit facilities	782
Total net liquidity	$ 805
Credit facilities:	
Maturity dates	2017, 2018
Largest single bank commitment as a % of total credit facilities	7%

(1) Refer to Note 6 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion regarding PacifiCorp's credit facilities.

Operating Activities

Net cash flows from operating activities for the years ended December 31, 2014 and 2013 were $1.570 billion and $1.553 billion, respectively. The $17 million increase was primarily due to higher collections from retail customers, lower pension contributions, lower purchased electricity payments and higher receipts from wholesale electricity sales, partially offset by higher fuel payments, changes in cash collateral posted for derivative contracts and higher cash paid for income taxes.

Net cash flows from operating activities for the years ended December 31, 2013 and 2012 were $1.553 billion and $1.627 billion, respectively. The $74 million decrease was primarily due to cash paid for income taxes in 2013 versus cash received for income taxes in 2012 mainly due to reduced bonus depreciation benefits, lower REC sales, higher purchased electricity and lower cash collateral inflows for derivative contracts, partially offset by higher collections from retail customers due to higher rates and increased retail customer load and lower fuel payments.

In December 2014, the Tax Increase Prevention Act of 2014 (the "Act") was signed into law, extending the 50% bonus depreciation for qualifying property purchased and placed in-service before January 1, 2015 and before January 1, 2016 for certain longer-lived assets. As a result of the Act, PacifiCorp's cash flows from operations are expected to benefit in 2015 due to bonus depreciation on qualifying assets placed in-service.

Investing Activities

Net cash flows from investing activities for the years ended December 31, 2014 and 2013 were $(1.079) billion and $(1.049) billion, respectively. The change was primarily due to changes in other investing activities from net investments in Bridger Coal Company. Refer to "Future Uses of Cash" for discussion of capital expenditures.

Net cash flows from investing activities for the years ended December 31, 2013 and 2012 were $(1.049) billion and $(1.342) billion, respectively. The change was primarily due to lower capital expenditures of $281 million.

Financing Activities

Short-term Debt and Credit Facilities

Regulatory authorities limit PacifiCorp to $1.5 billion of short-term debt. PacifiCorp had $20 million of short-term debt outstanding as of December 31, 2014 at a weighted average interest rate of 0.43%. PacifiCorp had no short-term debt outstanding as of December 31, 2013. 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 March 2014, PacifiCorp issued $425 million of its 3.60% First Mortgage Bonds due April 2024. The net proceeds were used to fund capital expenditures and for general corporate purposes, including retirement of short-term debt that was partially incurred to pay a $500 million common stock dividend in March 2014 to PPW Holdings.

In June 2013, PacifiCorp issued $300 million of its 2.95% First Mortgage Bonds due June 2023. The net proceeds were used to fund capital expenditures and for general corporate purposes, including a portion of the common stock dividend paid to PPW Holdings in June 2013.

PacifiCorp currently has regulatory authority from the OPUC and the IPUC to issue an additional $1.575 billion of long-term debt. PacifiCorp must make a notice filing with the WUTC prior to any future issuance. PacifiCorp currently has an effective shelf registration statement filed with the SEC expected to provide for future first mortgage bond issuances through October 2016.

PacifiCorp made repayments on long-term debt totaling $236 million and $278 million during the years ended December 31, 2014 and 2013, respectively.

As of December 31, 2014, PacifiCorp had $451 million of letters of credit providing credit enhancement and liquidity support for variable-rate tax-exempt bond obligations totaling $444 million plus interest. These letters of credit were fully available as of December 31, 2014 and expire periodically through March 2017.

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, 2014, PacifiCorp estimated it would be able to issue up to $9.2 billion of new first mortgage bonds under the most restrictive issuance test in the mortgage. Any issuances are subject to market conditions and amounts may be further limited by regulatory authorizations or commitments or by covenants and tests contained in other financing agreements. PacifiCorp also has the ability to release property from the lien of the mortgage on the basis of property additions, bond credits or deposits of cash.

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

Preferred Stock

In 2013, PacifiCorp redeemed and canceled all outstanding shares of its redeemable preferred stock at stated redemption prices, which in aggregate totaled $40 million, plus accrued and unpaid dividends. As of December 31, 2014 and 2013, PacifiCorp had non-redeemable preferred stock outstanding with an aggregate stated value of $2 million.

Common Shareholder's Equity

In February 2015, PacifiCorp declared a dividend of $450 million payable to PPW Holdings in March 2015.

In 2014 and 2013, PacifiCorp declared and paid dividends of $725 million and $500 million, respectively, to PPW Holdings.

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, BHE, 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 markets, including the condition of the utility industry.

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 environmental and other 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.

Historical and forecasted capital expenditures, each of which exclude amounts for non-cash equity AFUDC and other non-cash items, for the years ended December 31 are as follows (in millions):

	Historical			Forecasted		
	2012	2013	2014	2015	2016	2017
Transmission system investment	$ 311	$ 278	$ 262	$ 146	$ 63	$ 130
Environmental	75	57	158	126	77	33
Lake Side 2	232	156	37	—	—	—
Other	728	574	609	693	633	626
Total	$ 1,346	$ 1,065	$ 1,066	$ 965	$ 773	$ 789

PacifiCorp's historical and forecasted capital expenditures include the following:

- Transmission system investments including construction costs for the 170-mile single-circuit 345-kV Sigurd-Red Butte ("Sigurd-Red Butte") transmission line expected to be placed in-service in May 2015 and the 100-mile high-voltage Mona-Oquirrh ("Mona-Oquirrh") transmission line that was placed in-service in May 2013. PacifiCorp anticipates costs for transmission system investments will total $339 million between 2015 and 2017, including the remaining costs for the Sigurd-Red Butte transmission line and development costs for certain projects associated with the Energy Gateway Transmission Expansion Program.

- Environmental projects including investments in emissions control equipment on existing generating facilities for installation or upgrade of selective catalytic reduction ("SCR") control systems and low-nitrogen oxide burners to reduce nitrogen oxides, particulate matter control systems and mercury emissions control systems. PacifiCorp anticipates costs for emissions control equipment will total $236 million between 2015 and 2017, including 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, primarily SCR control systems at Jim Bridger Units 3 and 4 and Craig Unit 2.

- Remaining investments relate to operating projects that consist of routine expenditures for transmission, distribution, generation 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, 2014 (in millions):

	Payments Due By Periods				
	2015	2016-2017	2018-2019	2020 and After	Total
Long-term debt, including interest:					
Fixed-rate obligations	$ 355	$ 698	$ 1,504	$ 9,621	$ 12,178
Variable-rate obligations(1)	125	104	86	257	572
Capital leases, including interest	5	15	11	31	62
Operating leases and easements	5	9	8	46	68
Asset retirement obligations	21	20	19	282	342
Power purchase agreements - commercially operable(2):					
Electricity commodity contracts	87	53	42	63	245
Electricity capacity contracts	73	89	66	192	420
Electricity mixed contracts	7	13	11	37	68
Power purchase agreements - non-commercially operable(2):	3	80	130	1,078	1,291
Transmission	116	214	173	617	1,120
Fuel purchase agreements(2):					
Natural gas supply and transportation	78	61	52	309	500
Coal supply and transportation	711	1,180	860	985	3,736
Other purchase obligations	280	120	43	89	532
Other long-term liabilities(3)	11	12	8	57	88
Total contractual cash obligations	$ 1,877	$ 2,668	$ 3,013	$ 13,664	$ 21,222

(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 assumed to equal December 31, 2014 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. PacifiCorp has several contracts for purchases of electricity from facilities that have not yet achieved commercial operation. To the extent any of these facilities do not achieve commercial operation, PacifiCorp has no obligation to the counterparty.

(3) Includes environmental and hydroelectric relicensing commitments recorded in the Consolidated Balance Sheets that are contractually or legally binding. Excludes regulatory liabilities and employee benefit plan obligations that are not legally or contractually fixed as to timing and amount. Deferred income taxes are 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 Mine Disposition

In December 2014, PacifiCorp filed applications with the UPSC, the OPUC, the WPSC and the IPUC and an advice letter with the CPUC seeking certain approvals, prudence determinations and accounting orders to close PacifiCorp's Deer Creek mining operations, sell certain Utah mining assets, enter into a replacement coal supply agreement, amend an existing coal supply agreement, withdraw from the UMWA 1974 Pension Trust and settle PacifiCorp's other postretirement benefit obligation for UMWA participants (collectively, the "Utah Mine Disposition").

The applications filed with the UPSC, the WPSC and the IPUC, request that the commissions approve: (a) closure of the Deer Creek mine; (b) asset sales to a third party for certain Utah mining assets, including the Cottonwood Preparatory Plant; (c) the execution of a long-term coal supply agreement for the Huntington generating facility and amendment to the existing long-term coal supply agreement for the Hunter generating facility; and (d) the withdrawal from the UMWA 1974 Pension Trust that will be triggered upon closure of the Deer Creek mine. In the UPSC and WPSC applications, PacifiCorp's request for approval to sell certain Utah mining assets includes the sale of the Fossil Rock coal reserves that are currently reflected in rates in Utah and Wyoming. In addition to the requested approvals, PacifiCorp's applications filed with the UPSC, the WPSC and the IPUC request that the noted components of the transaction and the settlement of PacifiCorp's other postretirement benefit obligation related to the UMWA participants be found prudent and in the public interest. These applications also request accounting orders to defer the costs associated with the Utah Mine Disposition for current or future recovery. As certain amounts are currently reflected in rates, such as the recovery through depreciation of the Deer Creek mining assets and assets to be sold, these amounts will serve to reduce the regulatory assets established as a result of the Utah Mine Disposition. The application requests continued recovery of contributions to the UMWA 1974 Pension Trust with ultimate ratemaking treatment of the UMWA 1974 Pension Trust withdrawal to be determined in a future proceeding once the final withdrawal obligation is determined.

PacifiCorp's application filed with the OPUC requests that the OPUC determine that closure of the Deer Creek mine is in the public interest, that its decision to enter into the Utah Mine Disposition is prudent and seeks approval to sell certain Utah mine assets. PacifiCorp also requests that the costs associated with the Utah Mine Disposition, including the unrecovered investments and closure costs, be transferred to or deferred as a regulatory asset and recovered through a one-year tariff rider beginning June 1, 2015 with an offset for amounts currently in rates. The application requests the same treatment of the UMWA 1974 Pension Trust withdrawal sought in the applications filed with the UPSC, the WPSC and the IPUC.

PacifiCorp's advice letter filed with the CPUC requests approval to sell certain Utah mining assets and seeks approval to establish memorandum accounts to track the costs associated with the Utah Mine Disposition for future recovery.

The asset sales and coal supply agreements are contingent upon regulatory approvals, which PacifiCorp has requested be issued no later than May 27, 2015 in order to close the transactions with the third party by May 31, 2015. For additional information related to the accounting impacts associated with the Utah Mine Disposition, refer to Notes 5 and 9 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Utah

In January 2014, PacifiCorp filed a general rate case with the UPSC requesting an annual increase of $76 million, or an average price increase of 4%. PacifiCorp filed subsequent rebuttal testimony reducing the requested increase to $66 million. The requested increase includes recovery of PacifiCorp's investment in Lake Side 2, which was placed in-service in May 2014, and the Mona-Oquirrh transmission line investment found to be prudent in the prior general rate case. In August 2014, the UPSC approved a multi-party stipulation that provides for a two-step rate increase. The first increase of $35 million, or an average price increase of 2%, was effective September 2014, and the second increase of $19 million, or an average price increase of 1%, will be effective the later of September 2015 or the in-service date of the Sigurd-Red Butte transmission line. The stipulation resolved most issues in the general rate case, but did not settle the net metering facilities charge proposed by PacifiCorp, which was moved by the UPSC to a new docket for further analysis. The stipulation also specifies that September 2016 would be the earliest effective date that PacifiCorp could seek an increase to customers' rates in Utah, with the exception of the year-two increase agreed to above and other UPSC-approved and currently existing rate adjustment mechanisms, including the EBA pilot for which the stipulation provides a one-year extension through 2016.

In March 2014, PacifiCorp filed its annual EBA with the UPSC requesting $28 million, or an increase of 2%, for recovery of deferred net power costs for the period January 1, 2013 through December 31, 2013. In October 2014, the UPSC approved an all-party stipulation providing for a rate increase of $25 million, or 1%, effective November 2014. The parties to the stipulation agreed that, effective November 2014, the $25 million would be combined with the remaining deferral balances currently being collected in the EBA of $19 million, with the total balance of $44 million to be collected over a 12-month period beginning November 2014.

In March 2014, PacifiCorp filed its annual REC balancing account application with the UPSC requesting recovery of $17 million over a three-year period. In May 2014, the UPSC approved interim rates effective June 2014. In September 2014, the UPSC issued a final order approving the interim rates as final.

Oregon

In April 2014, PacifiCorp made its initial filing for the annual TAM with the OPUC for an annual increase of $18 million, or an average price increase of 2%, based on forecasted net power costs for calendar year 2015. In July 2014, PacifiCorp filed an all-party stipulation with the OPUC resolving all issues in the proceeding. In October 2014, the OPUC issued an order approving the stipulation. In November 2014, PacifiCorp filed final updated net power costs with the OPUC, resulting in an overall rate increase of $6 million, or less than 1%, effective January 2015.

In April 2014, PacifiCorp filed for a separate tariff rider with the OPUC to recover the Oregon-allocated costs of PacifiCorp's investment in Lake Side 2. The separate tariff rider was agreed to in the 2013 Oregon general rate case stipulation with final costs subject to a prudence determination. The filing supported an overall rate increase of $22 million, or an average price increase of 2%. In May 2014, the OPUC approved the new rates effective June 2014.

Wyoming

In March 2014, PacifiCorp filed a general rate case with the WPSC requesting an annual increase of $36 million, or an average price increase of 5%. In September 2014, PacifiCorp filed rebuttal testimony reducing the requested increase to $32 million, or an average price increase of 5%. The requested increase includes recovery of PacifiCorp's investments in Lake Side 2 and the Mona-Oquirrh transmission line. Hearings were held by the WPSC in October 2014. In December 2014, the WPSC approved an annual increase of $20 million, or an average price increase of 3%, effective January 2015.

In March 2014, PacifiCorp filed its annual ECAM and RRA applications with the WPSC. The ECAM filing requests recovery of $17 million of deferred net power costs for the period January 1, 2013 through December 31, 2013, and the RRA application requests a $4 million increase in the RRA surcharge. The two applications represent a combined total price increase of 3%. In May 2014, the WPSC approved the ECAM and RRA rates effective May 2014 on an interim basis subject to further investigation and hearing. In December 2014, the WPSC approved the applications with no adjustments.

Washington

In December 2012, PacifiCorp submitted a compliance filing with the WUTC presenting Washington-allocated actual REC sales revenues of $17 million from January 1, 2009 through April 2, 2011. Also in December 2012, PacifiCorp filed for judicial review of the WUTC's August 2012 order requiring PacifiCorp to credit to its retail customers all proceeds from the sale of RECs attributable to Washington that were recorded on or after January 1, 2009, less any amounts already credited to retail customers, and the WUTC's November 2012 order denying PacifiCorp's petition for reconsideration and stay of the August 2012 order. In June 2014, a multi-party stipulation was filed with the WUTC resolving the request for judicial review associated with the appropriate rate treatment of REC sales revenues from January 1, 2009 through April 2, 2011. The terms of the settlement included a one-time credit to customers totaling $13 million for REC sales revenues from January 1, 2009 through April 2, 2011. The WUTC approved the stipulation and the one-time credit to customers effective June 2014. In July 2014, the Washington State Court of Appeals granted the parties' joint motion to dismiss the petition for judicial review.

In May 2014, PacifiCorp filed a general rate case with the WUTC requesting an annual increase of $27 million, or an average price increase of 8%. In November 2014, PacifiCorp filed rebuttal testimony that increased the request to $32 million, or an average price increase of 10%, primarily as a result of updated net power costs. The WUTC held evidentiary hearings in December 2014. If approved by the WUTC, the new rates will be effective March 2015.

In October 2014, PacifiCorp filed for a temporary rate increase of $5 million to recover the amount of Washington-allocated revenues from the sale of RECs reflected in customers' rates in excess of actual revenues from April 3, 2011 through December 31, 2013. In December 2014, the WUTC issued an order authorizing recovery of $5 million over a two-year period effective March 2015.

Idaho

In January 2014, PacifiCorp filed its annual ECAM application with the IPUC requesting recovery of $13 million of deferred net power costs. In April 2014, the IPUC issued an order approving recovery of $12 million of deferred net power costs, of which $7 million will be collected over a 12-month period and the remainder collected over a 24-month period, with new rates effective April 2014.

In February 2015, PacifiCorp filed its annual ECAM application with the IPUC requesting recovery of $17 million of deferred net power costs. If approved by the IPUC, the new rates will be effective April 2015.

California

In July 2014, PacifiCorp filed for a rate increase of $2 million, or 2%, through its PTAM for major capital additions to add Lake Side 2 and the Hunter Unit 1 emissions control equipment to rates. The CPUC approved the new rates effective August 2014.

In August 2014, PacifiCorp filed for a rate increase of $5 million, or 4%, through its annual ECAC. No party contested PacifiCorp's requested increase and the CPUC decision is pending.

In October 2014, 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 2014, the CPUC approved the new rates effective January 2015.

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 state and local agencies. PacifiCorp believes it is in material compliance with all applicable laws and regulations, although many are subject to interpretation that may ultimately be resolved by the courts. 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 State Implementation Plans ("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. Currently, with the exceptions described in the following paragraphs, air quality monitoring data indicates that all counties where PacifiCorp's major emission sources are located are in attainment of the current national ambient air quality standards.

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 fine particulate matter 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 existing generating facilities that would have a material impact on PacifiCorp's consolidated financial results.

In November 2014, the EPA released a new proposal to strengthen the national ambient air quality standard for ground level ozone from the current level of 75 parts per billion to a level between 65 and 70 parts per billion. Review or revision is required to be complete by October 2015. Until the standards' review or revision is complete, the EPA is proceeding with implementation of the 2008 ozone standards. The Upper Green River Basin Area in Wyoming, including all of Sublette and portions of Lincoln and Sweetwater Counties, were proposed to be designated as nonattainment for the 2008 ozone standard. When the final designations were released in April 2012, portions of Lincoln and Sweetwater Counties and Sublette County were determined 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 has not been impacted by the 2012 designation.

In January 2010, the EPA finalized a one-hour air quality standard for nitrogen dioxide at 100 parts per billion. 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 2010 rule, areas must meet a one-hour standard of 75 parts per billion utilizing a three-year average. The rule utilizes source modeling in addition to the installation of ambient monitors where sulfur dioxide emissions impact populated areas. Attainment designations were due by June 2012; however, citing a lack of sufficient information to make the designations, the EPA did not issue its final designations until July 2013. Although the EPA's July 2013 designations did not impact PacifiCorp's generating facilities, the EPA's assessment of sulfur dioxide area designations will continue with the deployment of additional sulfur dioxide monitoring networks across the country.

In December 2012, the EPA finalized more stringent fine particulate matter national ambient air quality standards, reducing the annual standard from 15 micrograms per cubic meter to 12 micrograms per cubic meter 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. In December 2014, the EPA issued final area designations for the 2012 fine particulate matter standard. Based on these designations, the areas in which PacifiCorp operates generating facilities have been classified as "unclassifiable/attainment." Unless additional monitoring suggests otherwise, PacifiCorp does not anticipate that any impacts of the revised standard will be significant.

As new, more stringent national ambient air quality 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 also become more difficult in nonattainment areas. Until new requirements are promulgated and additional monitoring and modeling is conducted, the impacts on PacifiCorp cannot be determined.

Mercury and Air Toxics Standards

In March 2011, the EPA proposed a rule that requires coal-fueled generating facilities to reduce mercury emissions and other hazardous air pollutants through the establishment of "Maximum Achievable Control Technology" standards. The final rule, Mercury and Air Toxics Standards ("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 generating 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. 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 is proceeding with additional actions to reduce mercury emissions through the installation of controls and use of sorbent injection at certain of its coal-fueled generating facilities to otherwise comply with the final rule's standards.

PacifiCorp plans to retire the Carbon Facility in April 2015 as the least-cost alternative to comply with the MATS and other environmental regulations. Efforts are underway to effectuate the decommissioning activities and transmission system modifications necessary to maintain system reliability following disconnection. The Carbon Facility produced 1.3 million MWh of electricity, or 2.1% of PacifiCorp's owned generation production, during 2014.

Incremental costs to install and maintain emissions control equipment at PacifiCorp's coal-fueled generating facilities and any resulting shut down of what have traditionally been low cost coal-fueled generating facilities will likely increase the cost of providing service to customers. Numerous lawsuits have been filed in the United States Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") challenging the MATS. In April 2014, the D.C. Circuit upheld the MATS requirements. In November 2014, the United States Supreme Court agreed to hear the MATS appeal on the limited issue of whether the EPA unreasonably refused to consider costs in determining whether it is appropriate to regulate hazardous air pollutants emitted by electric utilities. The outcome of the United States Supreme Court's decision is uncertain and until the court renders its decision or otherwise implements a stay of the MATS requirements, PacifiCorp is proceeding to fulfill its legal obligations to comply with the MATS.

Regional Haze

The EPA's Regional Haze Rule, finalized in 1999, requires states to develop and implement plans to improve visibility in designated federally protected areas ("Class I areas"). Some of PacifiCorp's coal-fueled generating facilities in Utah, Wyoming and Arizona 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 ("BART") 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 appealed the EPA's approval of the sulfur dioxide portion and oral argument was heard before the United States Court of Appeals for the Tenth Circuit ("Tenth Circuit") in March 2014. In October 2014, the Tenth Circuit upheld the EPA's approval of the sulfur dioxide portion of the SIP. The state of Utah and PacifiCorp filed petitions for administrative and judicial review of the EPA's final rule on the BART determinations for the nitrogen oxides and particulate matter portions of Utah's regional haze SIP in March 2013. Oral argument was held before the Tenth Circuit in March 2014. In May 2014, the Tenth Circuit dismissed the petition on jurisdictional grounds. In addition, and separate from the EPA's approval process and related litigation, the Utah Division of Air Quality has undertaken an additional BART analysis for Hunter Units 1 and 2, and Huntington Units 1 and 2, for which the public comment period closed in December 2014. The additional analysis will be provided to the EPA as a supplement to the existing Utah SIP once the Utah Division of Air Quality responds to the public comments. It is unknown whether and how this supplemental analysis will impact the EPA's decision regarding the Utah SIP.

The state of Wyoming 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. Certain groups have appealed the EPA's approval of the sulfur dioxide SIP, and PacifiCorp has intervened in that appeal. Oral argument was held before the Tenth Circuit in March 2014. In October 2014, the Tenth Circuit upheld the EPA's approval of the sulfur dioxide portion of the SIP. In addition, the EPA initially proposed in June 2012 to disapprove portions of the nitrogen oxides and particulate matter SIP and instead issue a federal implementation plan ("FIP"). The EPA withdrew its initial proposed actions on the nitrogen oxides and particulate matter SIP and the proposed FIP, published a re-proposed rule in June 2013, and finalized its determination in January 2014, which aligns more closely with the SIP proposed by the state of Wyoming. The EPA's final action on the Wyoming SIP approved the state's plan to have PacifiCorp install low-nitrogen oxides burners at Naughton Units 1 and 2, SCR controls at Naughton Unit 3 by December 2014, SCR controls at Jim Bridger Units 1 through 4 between 2015 and 2022, and low-nitrogen oxides burners at Dave Johnston Unit 4. The EPA disapproved the Wyoming SIP and issued a FIP for Dave Johnston Unit 3, where it required the installation of SCR controls by 2019 or, in lieu of installing SCR controls, a commitment to shut down Dave Johnston Unit 3 by 2027, its currently approved depreciable life. The EPA also disapproved the Wyoming SIP and issued a FIP for the Wyodak coal-fueled generating facility ("Wyodak Facility"), requiring the installation of SCR controls within five years (i.e., by 2019). The EPA action became final on March 3, 2014. PacifiCorp filed an appeal of the EPA's final action on the Wyodak Facility in March 2014. The state of Wyoming has also filed an appeal of the EPA's final action, as have the Powder River Basin Resource Council, National Parks Conservation Association and Sierra Club. In September 2014, the Tenth Circuit issued a stay of the March 2019 compliance deadline for the Wyodak Facility, pending further action by the Tenth Circuit in the appeal. In June 2014, the Wyoming Department of Environmental Quality issued a revised BART permit providing for the Naughton Unit 3 natural gas conversion in 2018 and allowing the unit to operate on coal through 2017. In its final action, the EPA indicated it supported the conversion of the unit to natural gas and would expedite action relative to consideration of the natural gas conversion once the state of Wyoming submitted the requisite SIP amendment; nonetheless, the Naughton Unit 3 natural gas conversion remains subject to final approval by the EPA.

The state of Arizona 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 requiring SCR controls on Cholla Unit 4. 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 issued an order on February 20, 2015, holding the matter in abeyance relating to PacifiCorp and Arizona Public Service Company as they work with state and federal agencies on an alternate compliance approach for Cholla Unit 4. In January 2015, Arizona Public Service Company submitted the permit applications and studies required to amend the Title V permit, and subsequently the Arizona SIP to convert Cholla Unit 4 to a natural gas-fueled unit in 2025. The amended plan is currently awaiting review and approval by the state of Arizona and after approval will be submitted to the EPA for review and approval.

The state of Colorado issued a regional haze SIP, which was approved by the EPA, and requires, among other things, the installation of selective non-catalytic reduction technology by 2018 at Craig Unit 1, in which PacifiCorp has an ownership interest. Environmental groups appealed the EPA's action, in which PacifiCorp intervened in support of the EPA. In July 2014, parties to the litigation, other than PacifiCorp, entered into a settlement agreement which required the installation of SCR controls at Craig Unit 1 by 2021. PacifiCorp opposed the settlement agreement. Nonetheless, the Tenth Circuit has granted the EPA's remand and vacatur of its previous action, which is currently pending. The state of Colorado regional haze SIP also requires SCR controls at Craig Unit 2 and Hayden Units 1 and 2, in which PacifiCorp has ownership interests. Each of those regional haze compliance projects are underway.

A case was filed in the Tenth Circuit appealing a FIP issued by the EPA in New Mexico. In addition, two cases involving the EPA's issuance of a FIP were appealed to the United States Supreme Court in 2014, one from the Tenth Circuit based on the EPA rejecting portions of the Oklahoma SIP and one from the United States Court of Appeals for the Eighth Circuit based on the EPA's rejection of the North Dakota SIP. In May 2014, the United States Supreme Court issued its decisions denying review of the Oklahoma and North Dakota SIPs.

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 Rule 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 a period of 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. In September 2013, PacifiCorp received a Section 114 request for information for certain projects and facilities in Wyoming and Utah. PacifiCorp provided timely responses to the request. 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. In June 2013, President Obama issued a Climate Action Plan, which, among other things, required the EPA to address GHG emissions from new, modified and existing fossil-fueled generating facilities under the Clean Air Act. Regulation of GHG emissions has proceeded under various provisions of the Clean Air Act since the EPA's December 2009 findings that GHG emissions threaten public health and welfare.

GHG Tailoring Rule

In May 2010, the EPA finalized the GHG "Tailoring Rule" 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 are also 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 became subject to permitting requirements. While the final rule also required facilities that were previously not subject to Title V permitting requirements to obtain Title V permits if they emit at least 100,000 tons per year of carbon dioxide equivalents, litigation over the Tailoring Rule resulted in a decision by the United States Supreme Court in June 2014 that the EPA could not utilize the Tailoring Rule to impose GHG permitting requirements on sources not otherwise subject to Clean Air Act permitting provisions. That decision did not impact PacifiCorp's sources that are already subject to Clean Air Act permitting. 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, which have not had a material impact on PacifiCorp's consolidated financial results.

GHG 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. As part of his Climate Action Plan, President Obama announced a national climate change strategy and issued a presidential memorandum requiring the EPA to issue a re-proposed GHG new source performance standard for fossil-fueled generating facilities by September 2013. The September 2013 GHG new source performance standards released by the EPA set different standards for coal-fueled and natural gas-fueled generating facilities. The proposed standard for natural gas-fueled generating facilities considers the size of the unit and the electricity sent to the grid from the unit, establishing a standard of 1,000 to 1,100 pounds of carbon dioxide per MWh. The standard proposed for coal-fueled generating facilities is 1,100 pounds of carbon dioxide per MWh on an annual basis or 1,000 to 1,050 pounds of carbon dioxide per MWh averaged over a seven-year period, both of which would require partial carbon capture and sequestration. The proposed standards were published in the Federal Register January 8, 2014, and the public comment period closed in May 2014. Any new fossil-fueled generating facilities constructed by PacifiCorp will be required to meet the GHG new source performance standards, which are expected to be finalized in the summer of 2015.

In June 2014, the EPA released proposed regulations to address GHG emissions from existing fossil-fueled generating facilities, referred to as the Clean Power Plan, under Section 111(d) of the Clean Air Act. The EPA's proposal calculated state-specific emission rate targets to be achieved based on four building blocks that it determined were the "Best System of Emission Reduction." The four building blocks include: (a) a 6% heat rate improvement from coal-fueled generating facilities; (b) increased utilization of existing combined-cycle natural gas-fueled generating facilities to 70%; (c) increased deployment of renewable and non-carbon generating resources; and (d) increased energy efficiency. Under the EPA's proposal, states may utilize any measure to achieve the specified emission reduction goals, with an initial implementation period of 2020-2029 and the final goal to be achieved by 2030. When fully implemented, the proposal is expected to reduce carbon dioxide emissions in the power sector to 30% below 2005 levels by 2030. The public comment period closed December 1, 2014 and the final guidelines are scheduled to be issued in the summer of 2015. States are required to submit implementation plans by June 2016, but they may request an extension to June 2017, or June 2018 if they plan to participate in a regional compliance program. The impacts of the proposal on PacifiCorp cannot be determined until the EPA finalizes the proposal and the states develop their implementation plans. PacifiCorp has historically pursued cost-effective projects, including plant efficiency improvements, increased diversification of its generating fleets to include deployment of renewable and lower carbon generating resources, and advancement of customer energy efficiency programs.

In November 2014, President Obama announced the United States and China had reached a climate change agreement under which the United States intends to achieve an economy-wide target of reducing its emissions by 26% to 28% below 2005 levels in 2025 and China would peak its GHG emissions around 2030 and increase the share of non-fossil fuels in primary energy consumption to 20% by 2030.

While the discussion 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 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, 2014, PacifiCorp owned 1,030 MW of operating wind-powered generating capacity at a total cost of $2.1 billion.
- PacifiCorp owns 1,145 MW of hydroelectric generating capacity.
- Investments in transmission systems that: (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.
- 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 greater 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.

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:

- 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 were 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 with ongoing quarterly auctions.

- The states of California, Washington and Oregon have adopted GHG emissions performance standards for base load electricity generating resources. Under the laws in California and Oregon, the emissions performance standards provide that emissions must not exceed 1,100 pounds of carbon dioxide per MWh. Effective April 2013, Washington's amended emissions performance standards provide that GHG emissions for base load electricity generating resources must not exceed 970 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.

- Washington and Oregon 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. Numerous lawsuits have been unsuccessfully pursued against the industry that attempt to link GHG emissions to public or private harm. The lower courts initially refrained from adjudicating the cases under the "political question" doctrine, because of their inherently political nature. These cases have typically been appealed to federal appellate courts and, in certain circumstances, to the United States Supreme Court. An adverse ruling in similar cases would likely result in increased regulation and costs for GHG emitters, including PacifiCorp's generating facilities.

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. PacifiCorp believes it is in material compliance with all applicable RPS laws and regulations.

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 each year thereafter. In April 2013, Washington State Senate Bill No. 5400 ("SB 5400") was signed into law. SB 5400 expands the geographic area in which eligible renewable resources may be located to beyond the Pacific Northwest, allowing renewable resources located in all states served by PacifiCorp to qualify. SB 5400 also provides PacifiCorp with additional flexibility and options to meet Washington's renewable mandates.

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. 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 product content 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. After significant litigation, the EPA released a proposed rule under §316(b) of the Clean Water Act to regulate cooling water intakes at existing facilities. The final rule was released in May 2014, and became effective in October 2014. Under the final rule, existing facilities that withdraw at least 25% of their water exclusively for cooling purposes and have a design intake flow of greater than two million gallons per day are required to reduce fish impingement (i.e., when fish and other aquatic organisms are trapped against screens when water is drawn into a facility's cooling system) by choosing one of seven options. Facilities that withdraw at least 125 million gallons of water per day from waters of the United States must also conduct studies to help their permitting authority determine what site-specific controls, if any, would be required to reduce entrainment of aquatic organisms (i.e., when organisms are drawn into the facility). PacifiCorp is assessing the options for compliance at its generating facilities impacted by the final rule and will complete impingement and entrainment studies. PacifiCorp's Dave Johnston generating facility withdraws more than 125 million gallons per day of water from waters of the United States for once-through cooling applications. PacifiCorp's Jim Bridger, Naughton, Gadsby, Hunter, Carbon and Huntington generating facilities currently utilize closed cycle cooling towers but are designed to withdraw more than two million gallons of water per day. The standards are required to be met as soon as possible after the effective date of the final rule, but no later than eight years thereafter. The costs of compliance with the cooling water intake structure rule cannot be fully determined until 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.

In June 2013, the EPA published proposed effluent limitation guidelines and standards for the steam electric power generating sector. These guidelines, which had not been revised since 1982, were revised in response to the EPA's concerns that the addition of controls for air emissions have changed the effluent discharged from coal- and natural gas-fueled generating facilities. While the EPA expected the final rule to be published in May 2014, the final rule is now scheduled for release by September 30, 2015. It is likely that the new guidelines will impose more stringent limits on wastewater discharges from coal-fueled generating facilities and associated ash and scrubber ponds. However, until the revised guidelines are finalized, PacifiCorp cannot predict the impact on its generating facilities.

In April 2014, the EPA and the United States Army Corps of Engineers issued a joint proposal to address "Waters of the United States" to clarify protection under the Clean Water Act for streams and wetlands. The proposed rule comes as a result of United States Supreme Court decisions in 2001 and 2006 that created confusion regarding jurisdictional waters that were subject to permitting under either nationwide or individual permitting requirements. As currently proposed, a variety of projects that otherwise would have qualified for streamlined permitting processes under nationwide or regional general permits will be required to undergo more lengthy and costly individual permit procedures based on an extension of waters that will be deemed jurisdictional. The public comment period closed November 14, 2014. Until the rule is finalized, PacifiCorp cannot determine whether projects that include construction and demolition will face more complex permitting issues, higher costs or increased requirements for compensatory mitigation.

Coal Combustion Byproduct Disposal

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 Resource Conservation and Recovery Act ("RCRA"). The public comment period closed in November 2010. The final rule was released by the EPA on December 19, 2014 and will be effective 180 days after it is published in the Federal Register. The final rule regulates coal combustion byproducts as non-hazardous waste under RCRA Subtitle D and establishes minimum nationwide standards for the disposal of coal combustion residuals. Under the final rule, surface impoundments and landfills utilized for coal combustion byproducts may need to be closed unless they can meet the more stringent regulatory requirements.

As defined by the final rule, PacifiCorp operates 18 surface impoundments and seven landfills that contain coal combustion byproducts. PacifiCorp is assessing the requirements of the final rule to determine the costs of compliance.

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 evaluates hydroelectric systems to ensure environmental impacts are minimized, including the issuance of environmental impact statements for licensed projects both initially and upon relicensing. The FERC monitors the hydroelectric facilities for compliance with the license terms and conditions, which include environmental provisions. Refer to Note 13 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for 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 affordable. 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, 2014, PacifiCorp's credit ratings for its senior secured debt and its issuer credit ratings for 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 credit support provisions that in part base certain collateral requirements on credit ratings for senior unsecured debt as reported by 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, 2014, PacifiCorp would have been required to post $233 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 markets and firms not previously regulated, 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, many of which have been completed and others that have not yet been finalized.

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 position limits, mandatory clearing, exchange trading, capital, margin, reporting, recordkeeping and business conduct requirements. Many of these requirements are primarily for "swap dealers" and "major swap participants," but many of these also impose some requirements on almost all market participants, including PacifiCorp. The Dodd-Frank Reform Act provides certain exemptions from many of these requirements for commercial end-users when using derivatives to hedge or mitigate commercial risk of their businesses. PacifiCorp qualifies or 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 has determined that it is not a swap dealer or major swap participant. The outcome of pending and 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 as of the last day of each fiscal quarter. Management believes that PacifiCorp could have borrowed an additional $7.3 billion as of December 31, 2014 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 BHE'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, 2014, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to PPW Holdings or BHE 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 BHE as common equity. As of December 31, 2014, PacifiCorp's actual common stock equity percentage, as calculated under this measure, was 53.0%, and management believes that PacifiCorp could have declared a dividend of $2.3 billion under this commitment.

These commitments also restrict PacifiCorp from making any distributions to either PPW Holdings or BHE 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, 2014, PacifiCorp met the minimum required senior unsecured debt ratings for making distributions.

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 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 will be 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 or re-established as accumulated other comprehensive income (loss) ("AOCI"). Total regulatory assets were $1.705 billion and total regulatory liabilities were $944 million as of December 31, 2014. 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 its commodity price 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, 2014, PacifiCorp had no derivative contracts outstanding related to 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 estimated 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, 2014, PacifiCorp had a net derivative liability of $89 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 because any changes in assumptions could have a significant impact on the estimated fair value of the contracts. As of December 31, 2014, PacifiCorp had a net derivative asset of $4 million related to contracts where PacifiCorp uses internal models with significant unobservable inputs.

Classification and Recognition Methodology

PacifiCorp's derivative contracts are probable of inclusion in rates and 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, 2014, PacifiCorp had $85 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 pension plan and a subsidiary contributes to a multiemployer pension plan for benefits offered to certain bargaining units. 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, 2014, PacifiCorp recognized a net liability totaling $289 million for the funded status of its defined benefit pension and other postretirement benefit plans. As of December 31, 2014, amounts not yet recognized as a component of net periodic benefit cost that were included in regulatory assets and AOCI totaled $491 million and $(22) 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, 2014.

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 asset allocation and return assumptions for each asset class based on forward-looking views of the financial markets and historical performance. 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% by 2025, at which point the rate of increase 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, 2014 Benefit Obligations:				
Discount rate	$ (73)	$ 80	$ (18)	$ 19
Effect on 2014 Periodic Cost:				
Discount rate	$ (4)	$ 4	$ (2)	$ 2
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, mortality assumptions, plan changes and PacifiCorp's funding policy for each plan.

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 on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more likely than not to be 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 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 and expense related to certain property-related basis differences and other various differences on to its customers. As of December 31, 2014, these amounts were recognized as a regulatory asset of $446 million and a regulatory liability of $13 million and will be included in rates when the temporary differences reverse.

Revenue Recognition - Unbilled Revenue

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. Unbilled revenue was $243 million as of December 31, 2014. 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. PacifiCorp's VaR methodology is based on a 36-month forward position, 95% confidence interval and one-day holding period.

As of December 31, 2014, 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 $11 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 year ended December 31 (in millions):

	2014
Minimum VaR (measured)	$ 8
Average VaR (calculated)	12
Maximum VaR (measured)	15

PacifiCorp maintained compliance with its VaR limit procedures during the year ended December 31, 2014. 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 $28 million and $12 million as of December 31, 2014 and 2013, 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, 2014:			
Total commodity derivative contracts	$ (85)	$ (49)	$ (121)
As of December 31, 2013:			
Total commodity derivative contracts	$ (55)	$ (6)	$ (104)

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, 2014 and 2013, a regulatory asset of $85 million and $55 million, respectively, was recorded related to the net derivative liability of $85 million and $55 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 8 of this Form 10-K for additional discussion of PacifiCorp's short- and long-term debt.

As of December 31, 2014 and 2013, PacifiCorp had short- and long-term variable-rate obligations totaling $591 million and $597 million, respectively, that expose PacifiCorp to the risk of increased interest expense in the event of increases in short-term interest rates. The market risk related to PacifiCorp's variable-rate debt as of December 31, 2014 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, 2014 and 2013.

Credit Risk

PacifiCorp is exposed to counterparty credit risk associated with wholesale energy supply and marketing activities with other utilities, energy marketing companies, financial institutions and other market participants. Credit risk may be concentrated to the extent PacifiCorp's counterparties have similar economic, industry or other characteristics and due to direct or indirect relationships among the counterparties. Before entering into a transaction, PacifiCorp analyzes the financial condition of each significant wholesale counterparty, 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 further mitigate wholesale counterparty credit risk, 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. If required, PacifiCorp exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

As of December 31, 2014, PacifiCorp's aggregate credit exposure from wholesale activities totaled $214 million, based on settlement and mark-to-market exposures, net of collateral. As of December 31, 2014, $211 million, or 99%, of PacifiCorp's credit exposure was with counterparties having investment grade credit ratings by either Moody's Investor Service or Standard & Poor's Rating Services. As of December 31, 2014, two counterparties comprised $150 million, or 70%, 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, 2014.

Item 8. Financial Statements and Supplementary Data

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of PacifiCorp and subsidiaries (the "Company") as of December 31, 2014 and 2013, and the related consolidated statements of operations, comprehensive income, changes in shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2014. 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, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 27, 2015

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions)

ASSETS

	As of December 31, 2014	As of December 31, 2013
Current assets:		
Cash and cash equivalents	$ 23	$ 53
Accounts receivable, net	701	700
Income taxes receivable	133	—
Inventories:		
Materials and supplies	218	213
Fuel	199	241
Deferred income taxes	28	66
Regulatory assets	131	94
Other current assets	92	75
Total current assets	1,525	1,442
Property, plant and equipment, net	18,719	18,507
Regulatory assets	1,574	1,290
Other assets	449	420
Total assets	$ 22,267	$ 21,659

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,	
	2014	2013
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 465	$ 504
Income taxes payable	—	22
Accrued employee expenses	76	79
Accrued interest	110	110
Accrued property and other taxes	59	58
Short-term debt	20	—
Current portion of long-term debt and capital lease obligations	134	238
Regulatory liabilities	34	55
Other current liabilities	222	208
Total current liabilities	1,120	1,274
Regulatory liabilities	910	879
Long-term debt and capital lease obligations	6,919	6,639
Deferred income taxes	4,609	4,359
Other long-term liabilities	953	721
Total liabilities	14,511	13,872
Commitments and contingencies (Note 13)		
Shareholders' equity:		
Preferred stock	2	2
Common stock - 750 shares authorized, no par value, 357 shares issued and outstanding	—	—
Additional paid-in capital	4,479	4,479
Retained earnings	3,288	3,315
Accumulated other comprehensive loss, net	(13)	(9)
Total shareholders' equity	7,756	7,787
Total liabilities and shareholders' equity	$ 22,267	$ 21,659

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,		
	2014	**2013**	**2012**
Operating revenue	$ 5,252	$ 5,147	$ 4,882
Operating costs and expenses:			
Energy costs	1,997	1,924	1,818
Operations and maintenance	1,057	1,114	1,242
Depreciation and amortization	726	675	640
Taxes, other than income taxes	172	170	161
Total operating costs and expenses	3,952	3,883	3,861
Operating income	1,300	1,264	1,021
Other income (expense):			
Interest expense	(379)	(379)	(380)
Allowance for borrowed funds	25	29	29
Allowance for equity funds	51	57	58
Other, net	10	8	6
Total other income (expense)	(293)	(285)	(287)
Income before income tax expense	1,007	979	734
Income tax expense	309	297	197
Net income	$ 698	$ 682	$ 537

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,		
	2014	2013	2012
Net income	$ 698	$ 682	$ 537
Other comprehensive (loss) income, net of tax —			
Unrecognized amounts on retirement benefits, net of tax of $(3), $1 and $(2)	(4)	3	(3)
Comprehensive income	$ 694	$ 685	$ 534

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

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

	Preferred Stock	Common Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss, Net	Total Shareholders' Equity
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
Net income	—	—	—	682	—	682
Other comprehensive income	—	—	—	—	3	3
Preferred stock dividends declared	—	—	—	(2)	—	(2)
Common stock dividends declared	—	—	—	(500)	—	(500)
Redemption of preferred stock	(39)	—	—	(1)	—	(40)
Balance, December 31, 2013	2	—	4,479	3,315	(9)	7,787
Net income	—	—	—	698	—	698
Other comprehensive loss	—	—	—	—	(4)	(4)
Common stock dividends declared	—	—	—	(725)	—	(725)
Balance, December 31, 2014	$ 2	$ —	$ 4,479	$ 3,288	$ (13)	$ 7,756

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,		
	2014	**2013**	**2012**
Cash flows from operating activities:			
Net income	$ 698	$ 682	$ 537
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	726	675	640
Allowance for equity funds	(51)	(57)	(58)
Deferred income taxes and amortization of investment tax credits	297	230	312
Changes in regulatory assets and liabilities	(112)	(32)	1
Other, net	22	21	26
Changes in other operating assets and liabilities:			
Accounts receivable and other assets	5	(7)	(17)
Derivative collateral, net	(16)	43	68
Inventories	37	14	(35)
Income taxes, net	(155)	(26)	118
Accounts payable and other liabilities	119	10	35
Net cash flows from operating activities	1,570	1,553	1,627
Cash flows from investing activities:			
Capital expenditures	(1,066)	(1,065)	(1,346)
Other, net	(13)	16	4
Net cash flows from investing activities	(1,079)	(1,049)	(1,342)
Cash flows from financing activities:			
Proceeds from long-term debt	425	299	749
Repayments of long-term debt and capital lease obligations	(238)	(284)	(102)
Net proceeds from (repayments of) short-term debt	20	—	(688)
Redemption of preferred stock	—	(40)	—
Common stock dividends	(725)	(500)	(200)
Preferred stock dividends	—	(2)	(2)
Other, net	(3)	(4)	(9)
Net cash flows from financing activities	(521)	(531)	(252)
Net change in cash and cash equivalents	(30)	(27)	33
Cash and cash equivalents at beginning of period	53	80	47
Cash and cash equivalents at end of period	$ 23	$ 53	$ 80

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

(1) Organization and Operations

PacifiCorp, which includes PacifiCorp and its subsidiaries, is a United States regulated electric utility 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 other utilities, energy marketing companies, financial institutions and other market participants. 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 Berkshire Hathaway Energy Company ("BHE"), a holding company based in Des Moines, Iowa that owns subsidiaries principally engaged in energy businesses. BHE 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 will be 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 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, 2014 and 2013, 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 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):

	2014	2013	2012
Beginning balance	$ 8	$ 9	$ 9
Charged to operating costs and expenses, net	11	13	14
Write-offs, net	(12)	(14)	(14)
Ending balance	$ 7	$ 8	$ 9

Derivatives

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. 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.

Debt and equity AFUDC, which represent the estimated costs of debt and equity funds necessary to finance the construction of property, plant and equipment, 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, net) 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 and unbilled amounts. As of December 31, 2014 and 2013, unbilled revenue was $243 million and $258 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 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.

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 and expense for certain property-related basis differences and other various differences that PacifiCorp is required to pass on to its customers are charged or credited directly to a regulatory asset or liability. These amounts were recognized as regulatory assets of $446 million and $461 million as of December 31, 2014 and 2013, respectively, and regulatory liabilities of $13 million and $21 million as of December 31, 2014 and 2013, 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 or a regulatory asset or liability in the period of enactment. Valuation allowances are established when necessary to reduce deferred income tax assets to the amount that is more likely than not to be realized.

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 $27 million and $32 million as of December 31, 2014 and 2013, 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 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 on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the Consolidated Financial Statements from such a position are measured based on the largest benefit that is more likely than not to be 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 impact on PacifiCorp's consolidated financial results. PacifiCorp's unrecognized tax benefits are primarily included in 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 May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2014-09, which creates FASB Accounting Standards Codification ("ASC") Topic 606, "Revenue from Contracts with Customers" and supersedes ASC Topic 605, "Revenue Recognition." The guidance replaces industry-specific guidance and establishes a single five-step model to identify and recognize revenue. The core principle of the guidance is that an entity should recognize revenue upon transfer of control of promised goods or services to customers in an amount that reflects the consideration to which an entity expects to be entitled in exchange for those goods or services. Additionally, the guidance requires the entity to disclose further quantitative and qualitative information regarding the nature and amount of revenues arising from contracts with customers, as well as other information about the significant judgments and estimates used in recognizing revenues from contracts with customers. This guidance is effective for interim and annual reporting periods beginning after December 15, 2016. Early application is not permitted. This guidance may be adopted retrospectively or under a modified retrospective method where the cumulative effect is recognized at the date of initial application. 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 February 2013, the FASB issued ASU No. 2013-04, which amends FASB ASC Topic 405, "Liabilities." The amendments in this guidance require an entity to measure obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date as the amount the reporting entity agreed to pay plus any additional amounts the reporting entity expects to pay on behalf of its co-obligor. Additionally, the guidance requires the entity to disclose the nature and amount of the obligation, as well as other information about those obligations. PacifiCorp adopted this guidance on January 1, 2014. 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	2014	2013
Property, plant and equipment:			
Generation	10 - 67 years	$ 11,932	$ 11,058
Transmission	58 - 75 years	5,392	5,235
Distribution	20 - 70 years	6,197	6,030
Intangible plant[1]	5 - 65 years	879	857
Other	5 - 60 years	1,413	1,688
Property, plant and equipment in-service		25,813	24,868
Accumulated depreciation and amortization		(8,026)	(7,686)
Net property, plant and equipment in-service		17,787	17,182
Construction work-in-progress		932	1,325
Total property, plant and equipment, net		$ 18,719	$ 18,507

(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 3.0% for the year ended December 31, 2014 and 2.8% for each of the years ended December 31, 2013 and 2012.

Depreciation Study

As a result of PacifiCorp's depreciation study approved by its state regulatory commissions, PacifiCorp revised its depreciation rates effective January 1, 2014. The approved depreciation rates resulted in an increase in depreciation expense of $35 million for the year ended December 31, 2014 as compared to the year ended December 31, 2013.

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 $143 million and $159 million as of December 31, 2014 and 2013, respectively, and accumulated depreciation of $107 million and $118 million as of December 31, 2014 and 2013, 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, 2014 (dollars in millions):

	PacifiCorp Share	Facility in Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
Jim Bridger Nos. 1 - 4	67%	$ 1,134	$ 554	$ 116
Hunter No. 1	94	467	144	—
Hunter No. 2	60	290	88	1
Wyodak	80	450	183	5
Colstrip Nos. 3 and 4	10	231	125	1
Hermiston (1)	50	175	67	1
Craig Nos. 1 and 2	19	323	203	7
Hayden No. 1	25	55	27	12
Hayden No. 2	13	33	18	3
Foote Creek	79	37	22	—
Transmission and distribution facilities	Various	347	65	—
Total		$ 3,542	$ 1,496	$ 146

(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

Utah Mine Disposition

Due to quality issues with the coal reserves at PacifiCorp's Deer Creek mine in Utah and rising costs at PacifiCorp's wholly owned subsidiary, Energy West Mining Company, PacifiCorp believes the Deer Creek coal reserves are no longer able to be economically mined. As a result, in December 2014, PacifiCorp filed applications with the Utah Public Service Commission ("UPSC"), the Oregon Public Utility Commission ("OPUC"), the Wyoming Public Service Commission ("WPSC") and the Idaho Public Utilities Commission ("IPUC") seeking certain approvals, prudence determinations and accounting orders to close its Deer Creek mining operations, sell certain Utah mining assets, enter into a replacement coal supply agreement, amend an existing coal supply agreement, withdraw from the United Mine Workers of America ("UMWA") 1974 Pension Trust and settle PacifiCorp's other postretirement benefit obligation for UMWA participants (collectively, the "Utah Mine Disposition"). PacifiCorp also filed an advice letter with the California Public Utilities Commission ("CPUC"). The asset sales and coal supply agreements are contingent upon regulatory approvals for which orders are expected to be issued in the second quarter of 2015. As a result of the Utah Mine Disposition, PacifiCorp believes abandonment of the Deer Creek mine assets, sale of the specified Utah mining assets and withdrawal from the UMWA 1974 Pension Trust are probable. PacifiCorp expects to transfer funds from its other postretirement plan assets to the UMWA in June 2015 to effectuate the settlement of the portion of the obligation related to UMWA participants.

Regulatory Assets

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	2014	2013
Deferred income taxes[1]	26 years	$ 446	$ 461
Employee benefit plans[2]	8 years	491	390
Utah mine disposition[3]	Various	194	—
Unamortized contract values	8 years	123	146
Deferred net power costs	1 year	122	139
Unrealized loss on derivative contracts	4 years	85	55
Other	Various	244	193
Total regulatory assets		$ 1,705	$ 1,384
Reflected as:			
Current assets		$ 131	$ 94
Noncurrent assets		1,574	1,290
Total regulatory assets		$ 1,705	$ 1,384

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

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

(3) Amounts represent regulatory assets established as a result of the Utah Mine Disposition for the net property, plant and equipment not considered probable of disallowance and for the portion of losses associated with the assets held for sale, UMWA 1974 Pension Trust withdrawal and closure costs incurred to date considered probable of recovery.

PacifiCorp had regulatory assets not earning a return on investment of $1.505 billion and $1.244 billion as of December 31, 2014 and 2013, respectively.

Regulatory Liabilities

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	2014		2013	
Cost of removal[1]	26 years	$	873	$	843
Deferred income taxes	Various		13		21
Other	Various		58		70
Total regulatory liabilities		$	944	$	934
Reflected as:					
Current liabilities		$	34	$	55
Noncurrent liabilities			910		879
Total regulatory liabilities		$	944	$	934

(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 credit facilities as of December 31 (in millions):

2014:		
Credit facilities	$	1,200
Less:		
Short-term debt		(20)
Letters of credit and tax-exempt bond support		(398)
Net credit facilities	$	782
2013:		
Credit facilities	$	1,200
Less:		
Short-term debt		—
Letters of credit and tax-exempt bond support		(321)
Net credit facilities	$	879

PacifiCorp has a $600 million unsecured credit facility expiring in June 2017 and a $600 million unsecured credit facility expiring in March 2018. These credit facilities, which support PacifiCorp's commercial paper program, certain series of its tax-exempt bond obligations and provide for the issuance of letters of credit, 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, 2014, the weighted average interest rate on commercial paper borrowings outstanding was 0.43%. These 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. As of December 31, 2014, PacifiCorp was in compliance with the covenants of its credit facilities.

As of December 31, 2014 and 2013, PacifiCorp had $451 million and $559 million, respectively, of fully available letters of credit issued under committed arrangements, of which $270 million as of December 31, 2014 and 2013 were issued under the credit facilities. These letters of credit support PacifiCorp's variable-rate tax-exempt bond obligations and expire through March 2017.

As of December 31, 2014, PacifiCorp had approximately $16 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, 2014 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):

	2014			2013	
	Principal Amount	Carrying Value	Average Interest Rate	Carrying Value	Average Interest Rate
First mortgage bonds:					
5.50% to 8.635%, due through 2019	$ 862	$ 861	5.63%	$ 1,070	5.53%
2.95% to 8.53%, due 2021 to 2024	1,899	1,897	4.09	1,472	4.23
6.71% due 2026	100	100	6.71	100	6.71
5.90% to 7.70%, due 2031 to 2034	500	499	6.98	499	6.98
5.25% to 6.35%, due 2035 to 2039	2,800	2,792	5.97	2,791	5.97
4.10% due 2042	300	299	4.10	299	4.10
Tax-exempt bond obligations:					
Variable rates, due 2015 to 2025(1)	223	223	0.03	325	0.17
Variable rates, due 2015 to 2024(1)(2)	221	221	0.02	221	0.06
Variable rates, due 2016 to 2025(2)	36	36	0.22	51	0.22
Variable rates, due 2017 to 2018	91	91	0.22	—	—
Total long-term debt	7,032	7,019		6,828	
Capital lease obligations:					
8.75% to 14.61%, due through 2035	34	34	11.33	49	11.47
Total long-term debt and capital lease obligations	$ 7,066	$ 7,053		$ 6,877	

Reflected as:

	2014	2013
Current portion of long-term debt and capital lease obligations	$ 134	$ 238
Long-term debt and capital lease obligations	6,919	6,639
Total long-term debt and capital lease obligations	$ 7,053	$ 6,877

1) Supported by $451 million and $559 million of fully available letters of credit issued under committed bank arrangements as of December 31, 2014 and 2013, respectively.

2) 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.

PacifiCorp's long-term debt generally includes provisions that allow PacifiCorp to redeem the first mortgage bonds 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 March 2014, PacifiCorp issued $425 million of its 3.60% First Mortgage Bonds due April 2024. The net proceeds were used to fund capital expenditures and for general corporate purposes, including retirement of short-term debt that was partially incurred to pay a $500 million common stock dividend in March 2014 to PPW Holdings LLC, a wholly owned subsidiary of BHE and PacifiCorp's direct parent company ("PPW Holdings").

PacifiCorp currently has regulatory authority from the OPUC and the IPUC to issue an additional $1.575 billion 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 October 2016.

The issuance of PacifiCorp's first mortgage bonds is limited by available property, earnings tests and other provisions of PacifiCorp's mortgage. Approximately $25 billion of PacifiCorp's eligible property (based on original cost) was subject to the lien of the mortgage as of December 31, 2014.

PacifiCorp has entered into long-term agreements that qualify as capital leases and expire at various dates through March 2035 for transportation services, power purchase agreements and real estate. The transportation services agreements included as capital leases are for the right to use pipeline facilities to provide natural gas to two of PacifiCorp's generating facilities. Net capital lease assets of $34 million and $49 million as of December 31, 2014 and 2013, respectively, were included in property, plant and equipment, net in the Consolidated Balance Sheets.

As of December 31, 2014, the annual maturities of long-term debt and capital lease obligations, excluding unamortized discounts and including interest on capital lease obligations, for 2015 and thereafter are as follows (in millions):

	Long-term Debt	Capital Lease Obligations	Total
2015	$ 132	$ 5	$ 137
2016	57	5	62
2017	52	10	62
2018	586	6	592
2019	350	5	355
Thereafter	5,855	31	5,886
Total	7,032	62	7,094
Unamortized discount	(13)	—	(13)
Amounts representing interest	—	(28)	(28)
Total	$ 7,019	$ 34	$ 7,053

(8) Income Taxes

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

	2014	2013	2012
Current:			
Federal	$ 2	$ 54	$ (112)
State	10	13	(3)
Total	12	67	(115)
Deferred:			
Federal	260	204	283
State	43	29	33
Total	303	233	316
Investment tax credits	(6)	(3)	(4)
Total income tax expense	$ 309	$ 297	$ 197

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:

	2014	2013	2012
Federal statutory income tax rate	35%	35%	35%
State income taxes, net of federal income tax benefit	3	3	3
Federal income tax credits[1]	(7)	(7)	(9)
Other	—	(1)	(2)
Effective income tax rate	31%	30%	27%

(1) Primarily attributable to the impact of federal renewable electricity production tax credits for 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):

	2014	2013
Deferred income tax assets:		
Regulatory liabilities	$ 362	$ 355
Employee benefits	184	98
Derivative contracts and unamortized contract values	79	76
State carryforwards	68	68
Loss contingencies	70	67
Asset retirement obligations	47	48
Other	92	86
	902	798
Deferred income tax liabilities:		
Property, plant and equipment	(4,780)	(4,528)
Regulatory assets	(647)	(525)
Other	(56)	(38)
	(5,483)	(5,091)
Net deferred income tax liability	$ (4,581)	$ (4,293)
Reflected as:		
Deferred income taxes - current assets	$ 28	$ 66
Deferred income taxes - noncurrent liabilities	(4,609)	(4,359)
	$ (4,581)	$ (4,293)

The following table provides PacifiCorp's net operating loss and tax credit carryforwards and expiration dates as of December 31, 2014 (in millions):

	State
Net operating loss carryforwards	$ 1,417
Deferred income taxes on net operating loss carryforwards	$ 52
Expiration dates	2015 - 2032
Tax credit carryforwards	$ 16
Expiration dates	2015 - indefinite

The United States Internal Revenue Service has effectively settled its examination of PacifiCorp's income tax returns through December 31, 2009. State agencies have closed their examinations of PacifiCorp's income tax returns through March 31, 2006, except for the December 31,1995 and 1997 tax years in Utah and the March 31, 2004, 2005 and 2006 tax years in Colorado and Utah.

As of December 31, 2014 and 2013, PacifiCorp had unrecognized tax benefits totaling $14 million and $13 million, respectively, related to tax 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 income 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 and froze future accruals for active participants as of December 31, 2014. 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 continue to 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.

Utah Mine Disposition and Labor Agreement

In conjunction with the Utah Mine Disposition described in Note 5, in December 2014, Energy West Mining Company reached a labor settlement with the UMWA covering union employees at PacifiCorp's Deer Creek mining operations. As a result of the labor settlement, the UMWA agreed to assume PacifiCorp's other postretirement benefit obligation associated with UMWA plan participants in exchange for PacifiCorp transferring $150 million to the UMWA. Transfer of the assets to the UMWA and settlement of this obligation is expected to occur in June 2015, which will result in a remeasurement of the other postretirement plan assets and benefit obligation. No curtailment accounting will be triggered as a result of the settlement due to an insignificant impact to the average remaining service lives in the plan.

As a result of the intended closure of the Deer Creek mining operations, withdrawal from the UMWA 1974 Pension Trust could be triggered as early as spring 2015. Refer to "Multiemployer and Joint Trustee Pension Plans" below for further information regarding the withdrawal.

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		
	2014	2013	2012	2014	2013	2012
Service cost	$ 5	$ 6	$ 7	$ 6	$ 9	$ 7
Interest cost	57	54	61	28	25	28
Expected return on plan assets	(76)	(74)	(74)	(31)	(30)	(30)
Net amortization	29	48	34	2	8	4
Net periodic benefit cost	$ 15	$ 34	$ 28	$ 5	$ 12	$ 9

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	
	2014	2013	2014	2013
Plan assets at fair value, beginning of year	$ 1,171	$ 1,012	$ 486	$ 424
Employer contributions	10	63	1	8
Participant contributions	—	—	7	7
Actual return on plan assets	53	213	25	86
Benefits paid	(88)	(117)	(37)	(39)
Plan assets at fair value, end of year	$ 1,146	$ 1,171	$ 482	$ 486

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

	Pension		Other Postretirement	
	2014	2013	2014	2013
Benefit obligation, beginning of year	$ 1,230	$ 1,391	$ 598	$ 632
Service cost	5	6	6	9
Interest cost	57	54	28	25
Participant contributions	—	—	7	7
Actuarial loss (gain)	174	(104)	(63)	(36)
Benefits paid	(88)	(117)	(37)	(39)
Benefit obligation, end of year	$ 1,378	$ 1,230	$ 539	$ 598
Accumulated benefit obligation, end of year	$ 1,378	$ 1,229		

The actuarial gain associated with the other postretirement benefit obligation during the year ended December 31, 2014 includes a gain that reduced the benefit obligation resulting from the $150 million to be transferred to the UMWA in June 2015 as a result of the contractually binding labor settlement.

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	
	2014	2013	2014	2013
Plan assets at fair value, end of year	$ 1,146	$ 1,171	$ 482	$ 486
Less - Benefit obligation, end of year	1,378	1,230	539	598
Funded status	$ (232)	$ (59)	$ (57)	$ (112)
Amounts recognized on the Consolidated Balance Sheets:				
Other current liabilities	$ (4)	$ (4)	$ —	$ —
Other long-term liabilities	(228)	(55)	(57)	(112)
Amounts recognized	$ (232)	$ (59)	$ (57)	$ (112)

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 $51 million and $48 million as of December 31, 2014 and 2013, 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	
	2014	2013	2014	2013
Net loss	$ 520	$ 361	$ 41	$ 108
Prior service credit	(21)	(29)	(26)	(33)
Regulatory deferrals	(3)	(4)	2	2
Total	$ 496	$ 328	$ 17	$ 77

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2014 and 2013 is as follows (in millions):

	Regulatory Asset	Accumulated Other Comprehensive Loss	Total
Pension			
Balance, December 31, 2012	$ 599	$ 19	$ 618
Net gain arising during the year	(239)	(3)	(242)
Net amortization	(47)	(1)	(48)
Total	(286)	(4)	(290)
Balance, December 31, 2013	313	15	328
Net loss arising during the year	189	8	197
Net amortization	(28)	(1)	(29)
Total	161	7	168
Balance, December 31, 2014	$ 474	$ 22	$ 496

	Regulatory Asset
Other Postretirement	
Balance, December 31, 2012	$ 177
Net gain arising during the year	(92)
Net amortization	(8)
Total	(100)
Balance, December 31, 2013	77
Net gain arising during the year	(58)
Net amortization	(2)
Total	(60)
Balance, December 31, 2014	$ 17

The net loss, prior service credit and regulatory deferrals that will be amortized in 2015 into net periodic benefit cost are estimated to be as follows (in millions):

	Net Loss	Prior Service Credit	Regulatory Deferrals	Total
Pension	$ 50	$ (8)	$ (1)	$ 41
Other postretirement	2	(7)	1	(4)
Total	$ 52	$ (15)	$ —	$ 37

Plan Assumptions

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

	Pension			Other Postretirement		
	2014	2013	2012	2014	2013	2012
Benefit obligations as of December 31:						
Discount rate	4.00%	4.80%	4.05%	3.90%	4.90%	4.10%
Rate of compensation increase	2.75	3.00	3.00	N/A	N/A	N/A
Net periodic benefit cost for the years ended December 31:						
Discount rate	4.80%	4.05%	4.90%	4.90%	4.10%	4.95%
Expected return on plan assets	7.50	7.50	7.50	7.50	7.50	7.50
Rate of compensation increase	3.00	3.00	3.50	N/A	N/A	N/A

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

	2014	2013
Assumed healthcare cost trend rates as of December 31:		
Healthcare cost trend rate assumed for next year	8.00%	8.00%
Rate that the cost trend rate gradually declines to	5.00%	5.00%
Year that the rate reaches the rate it is assumed to remain at	2025	2019

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 for the year ended December 31, 2014	$ 3	$ (2)
Other postretirement benefit obligation as of December 31, 2014	—	—

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be $4 million and $- million, respectively, during 2015. 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 generally contribute an amount equal to the net periodic benefit cost, subject to tax deductibility limitations and other considerations.

The expected benefit payments to participants in PacifiCorp's pension and other postretirement benefit plans for 2015 through 2019 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments	
	Pension	Other Postretirement
2015	$ 106	$ 184
2016	111	29
2017	108	28
2018	107	28
2019	109	27
2020 - 2024	465	126

Projected benefit payments for the other postretirement plan in 2015 include the $150 million to be transferred to the UMWA in June 2015 as a result of the contractually binding labor settlement with the UMWA.

Plan Assets

Investment Policy and Asset Allocations

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

The target allocations (percentage of plan assets) for PacifiCorp's pension and other postretirement benefit plan assets are as follows as of December 31, 2014:

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

(1) PacifiCorp's Retirement Plan trust includes a separate account that is used to fund benefits for the other postretirement benefit plan. In addition to this separate account, the assets for the other postretirement benefit 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 are 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, 2014				
Cash equivalents	$ —	$ 8	$ —	$ 8
Debt securities:				
United States government obligations	15	—	—	15
Corporate obligations	—	53	—	53
Municipal obligations	—	8	—	8
Agency, asset and mortgage-backed obligations	—	48	—	48
Equity securities:				
United States companies	488	—	—	488
International companies	16	—	—	16
Investment funds[(2)]	217	223	—	440
Limited partnership interests[(3)]	—	—	70	70
Total	$ 736	$ 340	$ 70	$ 1,146
As of December 31, 2013				
Cash equivalents	$ —	$ 18	$ —	$ 18
Debt securities:				
United States government obligations	13	—	—	13
International government obligations	—	1	—	1
Corporate obligations	—	48	—	48
Municipal obligations	—	8	—	8
Agency, asset and mortgage-backed obligations	—	50	—	50
Equity securities:				
United States companies	489	—	—	489
International companies	16	—	—	16
Investment funds[(2)]	215	227	—	442
Limited partnership interests[(3)]	—	—	86	86
Total	$ 733	$ 352	$ 86	$ 1,171

(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 50% and 50%, respectively, for 2014 and 2013, and are invested in United States and international securities of approximately 43% and 57%, respectively, for 2014 and 42% and 58%, respectively, for 2013.

(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, 2014				
Cash and cash equivalents[2]	$ 139	$ —	$ —	$ 139
Debt securities:				
United States government obligations	8	—	—	8
Corporate obligations	—	18	—	18
Municipal obligations	—	2	—	2
Agency, asset and mortgage-backed obligations	—	16	—	16
Equity securities:				
United States companies	112	—	—	112
International companies	4	—	—	4
Investment funds[3]	84	94	—	178
Limited partnership interests[4]	—	—	5	5
Total	$ 347	$ 130	$ 5	$ 482
As of December 31, 2013				
Cash and cash equivalents	$ 3	$ 1	$ —	$ 4
Debt securities:				
United States government obligations	1	—	—	1
Corporate obligations	—	4	—	4
Municipal obligations	—	1	—	1
Agency, asset and mortgage-backed obligations	—	4	—	4
Equity securities:				
United States companies	167	—	—	167
International companies	6	—	—	6
Investment funds[3]	173	120	—	293
Limited partnership interests[4]	—	—	6	6
Total	$ 350	$ 130	$ 6	$ 486

(1) Refer to Note 12 for additional discussion regarding the three levels of the fair value hierarchy.

(2) In December 2014, PacifiCorp began to migrate funds to cash and cash equivalents in anticipation of the $150 million to be transferred to the UMWA in June 2015 as a result of the other postretirement settlement. Remaining investments were rebalanced to align to target investment allocations.

(3) Investment funds are substantially comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 63% and 37%, respectively, for 2014 and 49% and 51%, respectively, for 2013, and are invested in United States and international securities of approximately 64% and 36%, respectively, for 2014 and 70% and 30%, respectively, for 2013.

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

For level 1 investments, 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. For level 2 investments, the fair value is determined using pricing models or unquoted net asset values based on observable market inputs. For level 3 investments, 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 pension and other postretirement benefit plans' proportionate shares 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, 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
Actual return on plan assets still held at December 31, 2013	16	1
Purchases, sales, distributions and settlements	(26)	(2)
Balance, December 31, 2013	86	6
Actual return on plan assets still held at December 31, 2014	(1)	—
Purchases, sales, distributions and settlements	(15)	(1)
Balance, December 31, 2014	$ 70	$ 5

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 its subsidiary, Energy West Mining Company, contributes to the UMWA 1974 Pension Trust (plan number 002). Contributions to these pension plans are based on the terms of collective bargaining agreements.

As a result of the Utah Mine Disposition and UMWA labor settlement, PacifiCorp believes withdrawal by its subsidiary, Energy West Mining Company, from the UMWA 1974 Pension Trust is probable. As a result, PacifiCorp recorded its best estimate of the withdrawal obligation in December 2014 and deferred the portion of the obligation considered probable of recovery to a regulatory asset. The most recent estimate of the withdrawal obligation provided by the UMWA 1974 Pension Trust is $97 million for a withdrawal occurring by July 1, 2015. In the event of withdrawal, Energy West Mining Company may elect to make a lump sum payment or annual installment payments to settle the withdrawal obligation. PacifiCorp is seeking recovery of the withdrawal obligation from its customers as part of the regulatory filings associated with the Utah Mine Disposition.

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 although formed with the ability for other employers to participate in the plan, there are no other employers that participate in this 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. This is expected to occur upon Energy West Mining Company's withdrawal from the UMWA 1974 Pension Trust. If participating employers withdraw from a multiemployer 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.

The following table presents PacifiCorp's and Energy West Mining Company'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, 2014	2013	2012	Funding improvement plan	Surcharge imposed under PPA[(1)]	Contributions[(1)] 2014	2013	2012	Year contributions to plan exceeded more than 5% of total contributions[(2)]
UMWA 1974 Pension Trust	52-1050282	Critical	Seriously Endangered	Seriously Endangered	Implemented	Yes	$ 2	$ 3	$ 3	None
Local 57 Trust Fund	87-0640888	At least 80%	At least 80%	At least 80%	None	None	$ 9	$ 9	$ 12	2013, 2012, 2011

(1) PacifiCorp's and Energy West Mining Company'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 agreements and the number of mining hours worked for the UMWA 1974 Pension Trust, respectively, subject to ERISA minimum funding requirements. As a result of the plan's critical status, Energy West Mining Company was required to begin paying a surcharge for hours worked on and after December 1, 2014.

(2) For the UMWA 1974 Pension Trust, information is for plan years beginning July 1, 2012 and 2011. Information for the plan years beginning July 1, 2014 and 2013 is not yet available. For the Local 57 Trust Fund, information is for plan years beginning July 1, 2013, 2012 and 2011. Information for the plan year beginning July 1, 2014 is not yet available.

The current collective bargaining agreements governing the Local 57 Trust Fund expire in January 2016. The current collective bargaining agreement governing the UMWA 1974 Pension Trust expires in June 2016.

Defined Contribution Plan

PacifiCorp's 401(k) plan covers substantially all employees. PacifiCorp's contributions are based primarily on each participant's level of contribution and cannot exceed the maximum allowable for tax purposes. PacifiCorp's contributions to the 401(k) plan were $34 million, $35 million and $36 million for the years ended December 31, 2014, 2013 and 2012, 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 changes in laws and regulations, 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 $873 million and $843 million as of December 31, 2014 and 2013, respectively.

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

	2014	2013
Beginning balance	$ 138	$ 127
Change in estimated costs	(3)	3
Additions	—	8
Retirements	(6)	(6)
Accretion	6	6
Ending balance	$ 135	$ 138
Reflected as:		
Other current liabilities	$ 21	$ 18
Other long-term liabilities	114	120
	$ 135	$ 138

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.

In December 2014, the Environmental Protection Agency released its final rule regulating the management and disposal of coal combustion byproducts resulting from the operation of coal-fueled generating facilities, including requirements for the operation and closure of surface impoundment and ash landfill facilities. The final rule will be effective 180 days after it is published in the Federal Register. Under the final rule, surface impoundments and landfills utilized for coal combustion byproducts may need to be closed unless they can meet the more stringent regulatory requirements. PacifiCorp is currently evaluating the requirements and costs of the new rule and cannot determine the impact on its ARO liabilities at this time.

(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 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	Other Current Liabilities	Other Long-term Liabilities	Total
As of December 31, 2014					
Not designated as hedging contracts[1]:					
Commodity assets	$ 28	$ —	$ 1	$ —	$ 29
Commodity liabilities	(10)	—	(55)	(49)	(114)
Total	18	—	(54)	(49)	(85)
Total derivatives	18	—	(54)	(49)	(85)
Cash collateral receivable	—	—	14	14	28
Total derivatives - net basis	$ 18	$ —	$ (40)	$ (35)	$ (57)
As of December 31, 2013					
Not designated as hedging contracts[1]:					
Commodity assets	$ 11	$ —	$ 2	$ 1	$ 14
Commodity liabilities	(1)	—	(29)	(39)	(69)
Total	10	—	(27)	(38)	(55)
Total derivatives	10	—	(27)	(38)	(55)
Cash collateral receivable	—	—	—	12	12
Total derivatives - net basis	$ 10	$ —	$ (27)	$ (26)	$ (43)

(1) PacifiCorp's commodity derivatives are generally included in rates and as of December 31, 2014 and 2013, a regulatory asset of $85 million and $55 million, respectively, was recorded related to the net derivative liability of $85 million and $55 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):

	2014	2013
Beginning balance	$ 55	$ 121
Changes in fair value recognized in regulatory assets	45	15
Net (losses) gains reclassified to operating revenue	(4)	9
Net losses reclassified to energy costs	(11)	(90)
Ending balance	$ 85	$ 55

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	2014	2013
Electricity sales	Megawatt hours	(1)	(1)
Natural gas purchases	Decatherms	113	120
Fuel oil purchases	Gallons	3	15

Credit Risk

PacifiCorp is exposed to counterparty credit risk associated with wholesale energy supply and marketing activities with other utilities, energy marketing companies, financial institutions and other market participants. Credit risk may be concentrated to the extent PacifiCorp's counterparties have similar economic, industry or other characteristics and due to direct or indirect relationships among the counterparties. Before entering into a transaction, PacifiCorp analyzes the financial condition of each significant wholesale counterparty, 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 further mitigate wholesale counterparty credit risk, 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. 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 credit support provisions that in part base certain collateral requirements on credit ratings for senior unsecured debt as reported by one or more of the three recognized credit rating agencies. 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, 2014, 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 $113 million and $68 million as of December 31, 2014 and 2013, respectively, for which PacifiCorp had posted collateral of $28 million and $12 million, respectively, in the form of cash deposits. If all credit-risk-related contingent features for derivative contracts in liability positions had been triggered as of December 31, 2014 and 2013, PacifiCorp would have been required to post $75 million and $51 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, 2014					
Assets:					
Commodity derivatives	$ —	$ 25	$ 4	$ (11)	$ 18
Money market mutual funds[(2)]	30	—	—	—	30
	$ 30	$ 25	$ 4	$ (11)	$ 48
Liabilities - Commodity derivatives	$ —	$ (114)	$ —	$ 39	$ (75)
As of December 31, 2013					
Assets:					
Commodity derivatives	$ —	$ 12	$ 2	$ (4)	$ 10
Money market mutual funds[(2)]	61	—	—	—	61
	$ 61	$ 12	$ 2	$ (4)	$ 71
Liabilities - Commodity derivatives	$ —	$ (69)	$ —	$ 16	$ (53)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $28 million and $12 million as of December 31, 2014 and 2013, 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 estimated 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 to record the fair value.

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):

	2014		2013	
	Carrying Value	**Fair Value**	**Carrying Value**	**Fair Value**
Long-term debt	$ 7,019	$ 8,358	$ 6,828	$ 7,626

(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 BHE'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 a May 2010 ruling on the Plaintiff's petition for reconsideration, the Utah Supreme Court reversed summary judgment and remanded the case back to the Third District Court for further consideration. In May 2012, a 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. 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. An initial judgment was entered in April 2013 in which the trial judge denied the Plaintiff's motions for exemplary damages and prejudgment interest and ruled that PacifiCorp must pay the Plaintiff's attorneys' fees based on applying a reasonable rate to hours worked. In May 2013, a final judgment was entered against PacifiCorp in the amount of $115 million, which includes the $113 million of aggregate damages previously awarded and amounts awarded for the Plaintiff's attorneys' fees. The final judgment also ordered that postjudgment interest accrue beginning as of the date of the April 2013 initial judgment. In May 2013, PacifiCorp posted a surety bond issued by a subsidiary of Berkshire Hathaway to secure its estimated obligation. PacifiCorp strongly disagrees with the jury's verdict and is vigorously pursuing all appellate measures. Both PacifiCorp and the Plaintiff filed appeals with the Utah Supreme Court. Briefing before the Utah Supreme Court is complete and oral arguments will most likely be held in 2015. As of December 31, 2014, PacifiCorp had accrued $119 million for the final judgment and postjudgment interest, 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 appeals process, which could take as long as several years.

Sanpete County, Utah Rangeland Fire

In June 2012, a major rangeland fire occurred in Sanpete County, Utah. Certain parties allege that contact between two of PacifiCorp's transmission lines may have triggered a ground fault that led to the fire. PacifiCorp has engaged experts to review the cause and origin of the fire, as well as to assess the damages. PacifiCorp has accrued its best estimate of the potential loss and expected insurance recovery. PacifiCorp believes it is reasonably possible it may incur additional loss beyond the amount accrued, but does not believe the potential additional loss will have a material impact on its consolidated financial results.

Environmental Laws and Regulations

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

Hydroelectric Relicensing

PacifiCorp's 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 May 2014, a bill was introduced in the United States Senate that, if passed by both houses of Congress, would enact the KHSA and companion agreements that seek to resolve other water-related conflicts and restore habitat in the Klamath basin. A hearing on the bill before a Senate Energy and Natural Resources subcommittee was held in June 2014, and the bill was voted out of committee and referred to the full Senate for consideration in November 2014. However, the bill was not passed by Congress prior to the end of the 2014 session. In January 2015, the bill was re-introduced into 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. Additional funding of up to $250 million for dam removal costs is to be provided by the State of California. California voters approved a water bond measure in November 2014 from which the State of California's contribution towards dam removal costs will be drawn. If dam removal costs exceed the combined funding that will be available from PacifiCorp's Oregon and California customers and the State of California, 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 and California customers for their share of dam removal costs, as approved by the OPUC and the CPUC, and is depositing the proceeds into trust accounts maintained by the OPUC and the CPUC, respectively. PacifiCorp is authorized to collect the surcharges through 2019.

As of December 31, 2014, PacifiCorp's assets included $92 million of costs associated with the Klamath hydroelectric system's mainstem dams and the associated relicensing and settlement costs, which are being depreciated and amortized in accordance with state regulatory approvals through either December 31, 2019 or 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 $203 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, 2014 are as follows (in millions):

	2015	2016	2017	2018	2019	2020 and Thereafter	Total
Contract type:							
Purchased electricity contracts - commercially operable	$ 167	$ 90	$ 65	$ 61	$ 58	$ 292	$ 733
Purchased electricity contracts - non-commercially operable	3	16	64	65	65	1,078	1,291
Fuel contracts	789	653	588	452	460	1,294	4,236
Construction commitments	231	53	12	8	2	8	314
Transmission	116	112	102	95	78	617	1,120
Operating leases and easements	5	5	4	4	4	46	68
Maintenance, service and other contracts	49	29	26	14	19	81	218
Total commitments	$ 1,360	$ 958	$ 861	$ 699	$ 686	$ 3,416	$ 7,980

Purchased Electricity Contracts - Commercially Operable

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 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 a lease. Rent expense related to those power purchase agreements that meet the definition of a lease totaled $15 million for 2014, $24 million for 2013 and $19 million for 2012.

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 2014, 2013 and 2012 energy sources.

Purchased Electricity Contracts - Non-commercially Operable

PacifiCorp has several contracts for purchases of electricity from facilities that have not yet achieved commercial operation. To the extent any of these facilities do not achieve commercial operation, PacifiCorp has no obligation to the counterparty.

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 costs associated with investments in emissions control equipment and certain transmission and distribution projects.

Transmission

PacifiCorp has contracts 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 $16 million for each of the years ended December 31, 2014 and 2013 and $14 million for the year ended December 31, 2012.

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 has 3,500 thousand shares of Serial Preferred Stock authorized at the stated value of $100 per share. PacifiCorp had 24 thousand shares of Serial Preferred Stock issued and outstanding as of December 31, 2014 and 2013. The outstanding preferred stock series are non-redeemable and have annual dividend rates of 6.00% and 7.00%.

In 2013, PacifiCorp redeemed and canceled all outstanding shares of its redeemable preferred stock at stated redemption prices, which in aggregate totaled $40 million, plus accrued and unpaid dividends.

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.

PacifiCorp also has 16 million shares of No Par Serial Preferred Stock and 127 thousand shares of 5% Preferred Stock authorized, but no shares were issued or outstanding as of December 31, 2014 and 2013.

(15) Common Shareholder's Equity

In February 2015, PacifiCorp declared a dividend of $450 million payable to PPW Holdings in March 2015.

Through PPW Holdings, BHE is the sole shareholder of PacifiCorp's common stock. The state regulatory orders that authorized BHE'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, 2014, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to PPW Holdings or BHE 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 BHE as common equity. As of December 31, 2014, PacifiCorp's actual common equity percentage, as calculated under this measure, was 53.0%, and PacifiCorp would have been permitted to dividend $2.3 billion under this commitment.

These commitments also restrict PacifiCorp from making any distributions to either PPW Holdings or BHE if PacifiCorp's senior 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, 2014, PacifiCorp met the minimum required senior unsecured debt ratings for making distributions.

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 $13 million and $9 million as of December 31, 2014 and 2013, 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 $38 million during each of the years ended December 31, 2014 and 2013 and $37 million during the year ended December 31, 2012. 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. Each joint venture partner is jointly and severally liable for the obligations of Bridger Coal. 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 $192 million and $178 million as of December 31, 2014 and 2013, 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 BHE and its subsidiaries. Amounts charged to PacifiCorp by BHE and its subsidiaries under this agreement totaled $10 million, $17 million and $15 million during the years ended December 31, 2014, 2013 and 2012, respectively. Payables associated with these administrative services were $1 million and $3 million as of December 31, 2014 and 2013, respectively. Amounts charged by PacifiCorp to BHE and its subsidiaries under this agreement totaled $10 million, $9 million and $3 million during the years ended December 31, 2014, 2013 and 2012, respectively. Receivables associated with these administrative services were $7 million and $2 million as of December 31, 2014 and 2013, respectively.

PacifiCorp also engages in various transactions with several subsidiaries of BHE in the ordinary course of business. Services provided by these subsidiaries in the ordinary course of business and charged to PacifiCorp primarily relate to the transportation of natural gas, wholesale electricity purchases and relocation services. These expenses totaled $7 million during the year ended December 31, 2014 and $5 million during each of the years ended December 31, 2013 and 2012. Payables associated with these services were $1 million and $- million as of December 31, 2014 and 2013, respectively. Amounts charged by PacifiCorp to subsidiaries of BHE for wholesale electricity sales in the ordinary course of business totaled $5 million during the year ended December 31, 2014 and $- million during each of the years ended December 31, 2013 and 2012.

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 $39 million, $32 million and $34 million during the years ended December 31, 2014, 2013 and 2012, respectively. As of December 31, 2014 and 2013, PacifiCorp had $3 million and $2 million, respectively, of accounts payable to BNSF outstanding under these contracts, including indirect payables related to a jointly owned facility.

PacifiCorp participated in a captive insurance program provided by MEHC Insurance Services Ltd. ("MEISL"), a wholly owned subsidiary of BHE. 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. Receivables for claims were $2 million as of December 31, 2014 and 2013. Proceeds from claims were $- million, $1 million and $6 million during the years ended December 31, 2014, 2013 and 2012, 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, 2014, federal and state income taxes receivable from BHE were $133 million, and as of December 31, 2013, federal and state income taxes payable to BHE were $22 million. For the years ended December 31, 2014 and 2013, cash paid for federal and state income taxes to BHE totaled $161 million and $120 million, respectively. For the year ended December 31, 2012, cash received for federal and state income taxes from BHE totaled $215 million.

PacifiCorp transacts with its equity investees, Bridger Coal and Trapper Mining Inc. During the years ended December 31, 2014, 2013 and 2012, PacifiCorp charged Bridger Coal $3 million, $2 million and $1 million, respectively, for administrative support and management services, as well as materials, 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 $4 million as of December 31, 2014 and 2013. Services provided by equity investees to PacifiCorp primarily relate to coal purchases. During the years ended December 31, 2014, 2013 and 2012, coal purchases from PacifiCorp's equity investees totaled $146 million, $152 million and $144 million, respectively. Payables to PacifiCorp's equity investees were $19 million and $23 million as of December 31, 2014 and 2013, 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):

	2014	2013	2012
Interest paid, net of amounts capitalized	$ 340	$ 340	$ 331
Income taxes paid (received), net	$ 161	$ 120	$ (205)
Supplemental disclosure of non-cash investing and financing activities:			
Accounts payable related to property, plant and equipment additions	$ 140	$ 157	$ 167

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, 2014 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, 2014 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 (2013)" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the evaluation conducted under the framework in "Internal Control - Integrated Framework (2013)," PacifiCorp's management concluded that PacifiCorp's internal control over financial reporting was effective as of December 31, 2014.

PacifiCorp
February 27, 2015

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

PacifiCorp is an indirect subsidiary of BHE, and its directors consist of executive management from both BHE 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, 2015, with respect to the current directors and executive officers of PacifiCorp:

Gregory E. Abel, 52, Chairman of the Board of Directors and Chief Executive Officer of PacifiCorp since 2006. Mr. Abel has been BHE's Chairman of the Board of Directors since 2011, Chief Executive Officer since 2008, director since 2000, President since 1998, and was BHE's Chief Operating Officer from 1998 to 2008. Mr. Abel joined BHE in 1992 and has extensive executive management experience in the energy industry. Mr. Abel is also a director of H. J. Heinz Company.

Douglas L. Anderson, 56, Director. Mr. Anderson has been a director of PacifiCorp since 2006 and Executive Vice President, General Counsel and Corporate Secretary of BHE since 2012. Mr. Anderson was Senior Vice President, General Counsel and Corporate Secretary of BHE from 2001 to 2012. Mr. Anderson joined BHE in 1993 and has significant legal experience, including expertise in corporate governance, mergers and acquisitions, and ethics and compliance programs. Mr. Anderson is also a manager of MidAmerican Funding, LLC.

Cindy A. Crane, 53, President and Chief Executive Officer of Rocky Mountain Power since 2014; Vice President of Interwest Mining Company, a subsidiary of PacifiCorp, from 2009 to 2014; and Vice President of Strategy and Division Services of PacifiCorp Energy from 2007 to 2009. Ms. Crane joined PacifiCorp in 1990 and has significant strategy, operational and leadership experience in the energy industry, including complex commercial negotiations.

Micheal G. Dunn, 49, 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 BHE, 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.

Patrick J. Goodman, 48, Director. Mr. Goodman has been a director of PacifiCorp since 2006 and Executive Vice President and Chief Financial Officer of BHE since 2012. Mr. Goodman was Senior Vice President and Chief Financial Officer of BHE from 1999 to 2012. Mr. Goodman joined BHE in 1995 and has significant financial experience, including expertise in mergers and acquisitions, accounting, treasury, and tax functions. Mr. Goodman is also a manager of MidAmerican Funding, LLC.

Natalie L. Hocken, 45, 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 experience in the utility industry, including expertise in transmission, legal matters, and federal and state regulatory compliance.

R. Patrick Reiten, 53, 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, 51, 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.

Board's Role in the Risk Oversight Process

PacifiCorp's Board of Directors is comprised of a combination of BHE 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, 2014, 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 BHE and PacifiCorp employees. PacifiCorp is not required to have an audit committee as its common stock is indirectly and wholly owned by BHE. However, the audit committee of BHE 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, Berkshire Hathaway Energy Company, or BHE, for the cost of Mr. Abel's time spent on matters supporting us, including compensation paid to him by BHE, pursuant to an intercompany administrative services agreement among BHE and its subsidiaries. Please refer to BHE's Annual Report on Form 10-K for the year ended December 31, 2014 (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 BHE'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 2014, base salaries for all NEOs, other than Mr. Abel, increased on average by 2.6% effective December 26, 2013.

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 2014. 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.

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 PacifiCorp 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 by January of each plan year. The BHE Chairman and PacifiCorp's Presidents designate eligibility to participate in the LTIP and the amount of the incentive award. Awards are capped at 1.0 times base salary and finalized in the first quarter of the following year. The BHE Chairman and PacifiCorp's Presidents may grant a supplemental award to any participant for the award year separate from the incentive award, subject to the same terms and conditions as the incentive award. PacifiCorp's Presidents may participate in the LTIP but only the BHE Chairman shall make determinations regarding their participation and the value of their incentive award. 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. The SERP benefit was frozen for participants effective December 31, 2014. Mr. Walje was the only NEO who participated in our SERP during 2014. 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 SERP, LTIP, DCP and our non-contributory defined benefit pension plan, or the Retirement Plan.

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]	2014	$ —	$ —	$ —	$ —	$ —
Chairman and	2013	—	—	—	—	—
Chief Executive Officer	2012	—	—	—	—	—
A. Richard Walje [6]	2014	379,034	873,487	668,436	30,355	1,951,312
Former President and Chief Executive	2013	372,000	881,283	—	29,652	1,282,935
Officer, Rocky Mountain Power	2012	368,000	768,541	428,807	30,970	1,596,318
R. Patrick Reiten	2014	320,000	1,167,125	822	25,980	1,513,927
President and Chief Executive	2013	310,000	1,137,462	3	25,245	1,472,710
Officer, Pacific Power	2012	300,000	996,621	—	24,900	1,321,521
Micheal G. Dunn	2014	320,000	1,049,862	16,917	117,295	1,504,074
President and Chief Executive	2013	310,000	1,022,446	14,521	117,038	1,464,005
Officer, PacifiCorp Energy	2012	300,000	677,088	12,725	27,782	1,017,595
Douglas K. Stuver	2014	252,000	421,772	21,443	29,808	725,023
Senior Vice President and	2013	246,495	415,937	—	28,985	691,417
Chief Financial Officer	2012	244,055	370,172	15,179	29,953	659,359
Cindy A. Crane [6]	2014	224,538	580,950	79,542	73,838	958,868
President and Chief Executive	2013	—	—	—	—	—
Officer, Rocky Mountain Power	2012	—	—	—	—	—

(1) Consists of annual cash incentive awards earned pursuant to the AIP for our NEOs, a performance award for Ms. Crane in recognition of efforts to support our objectives and the vesting of LTIP awards and associated vested earnings. The breakout for 2014 is as follows:

			LTIP		
	AIP	Performance Award	Vested Awards	Vested Earnings	Total
A. Richard Walje	$ 250,000	$ —	$ 506,000	$ 117,487	$ 623,487
R. Patrick Reiten	350,000	—	565,000	252,125	817,125
Micheal G. Dunn	350,000	—	550,000	149,862	699,862
Douglas K. Stuver	123,000	—	236,795	61,977	298,772
Cindy A. Crane	250,000	50,000	204,012	76,938	280,950

The ultimate payouts of LTIP awards are undeterminable as the amounts to be paid out may increase or decrease depending on investment performance. BHE's Chairman and PacifiCorp's Presidents establish the award categories for determining LTIP awards based on net income target goals or other criteria. In 2014, the gross award was subjectively determined at the discretion of the BHE Chairman and PacifiCorp Presidents based on the overall achievement of our financial and non-financial objectives including customer satisfaction, operational excellence, financial, safety, environmental, regulatory integrity and risk management goals.

(2) Amounts are based upon the aggregate increase in the actuarial present value of all qualified and nonqualified defined benefit plans, which include the Retirement Plan and the SERP, as applicable. Refer to the Pension Benefits table below for a discussion of the assumptions used in calculating these amounts. 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, registrant contributions to the DCP, as noted in the Nonqualified Deferred Compensation table, and the value of personal benefits. Items required to be reported are as follows: Mr. Walje - 401(k) contributions of $29,380; Mr. Reiten - 401(k) contributions of $25,480; Mr. Dunn - 401(k) contributions of $12,480, DCP contributions of $15,922 and home security services of $88,325; Mr. Stuver - 401(k) contributions of $29,308; and Ms. Crane - 401(k) contributions of $12,161, relocation expenses of $42,245 plus tax gross-up of $17,406 and vehicle usage. Mr. Dunn's home security services were valued based on the cost paid by PacifiCorp to the security company that provided the services. Ms. Crane's relocation services were valued based on the cost paid by PacifiCorp to the relocation company that provided the services.

(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 BHE for the cost of Mr. Abel's time spent on matters supporting us, including compensation paid to him by BHE, pursuant to an intercompany administrative services agreement among BHE and its subsidiaries. Please refer to BHE's Annual Report on Form 10-K for the year ended December 31, 2014 (File No. 001-14881) for executive compensation information for Mr. Abel.

(6) Ms. Crane was appointed President and CEO, Rocky Mountain Power on November 1, 2014 and was elected to that position on December 18, 2014. Mr. Walje was appointed President and CEO, Gateway Projects, PacifiCorp on November 1, 2014 and was elected to that position on December 18, 2014.

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, 2014:

Name	Plan name	Number of years of credited service	Present value of accumulated benefits [1]
Gregory E. Abel	n/a	n/a	n/a
A. Richard Walje	SERP	29 years	$ 3,686,019
	Retirement	23 years	1,276,393
R. Patrick Reiten	Retirement	2 years	16,858
Micheal G. Dunn [2]	Retirement	5 years	70,944
Douglas K. Stuver	Retirement	5 years	124,405
Cindy A. Crane	Retirement	19 years	389,217

(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, 2014, 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 4.0%; an expected retirement age of 60; and postretirement mortality using the RP-2014 tables (translated to 2011 using MP-2014 and adjusted for BHE credibility weighted experience, with custom RPEC 2014 generational improvements). The present value assumptions used in calculating the present value of accumulated benefits for the Retirement Plan were as follows: a discount rate of 4.0%; an expected retirement age of 65; postretirement mortality using the RP-2014 tables (translated to 2011 using MP-2014 and adjusted for BHE credibility weighted experience, with custom RPEC 2014 generational improvements); a lump sum interest rate of 4.0%; and lump sum mortality using the Internal Revenue Code Section 417(e)(3) Applicable Mortality Table for 2015.

(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 BHE.

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. In retirement, 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 under the Retirement Plan. 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 Section 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 Section 401(1)(5)(E)) times years of service.

The Retirement Plan was restated effective June 1, 2007 to change from a traditional final average pay formula as described above to a cash balance formula for non-union participants. Benefits under the final average pay formula were frozen as of May 31, 2007, and no future benefits will accrue under that formula for non-union participants. Under the cash balance formula, benefits are based on 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, 2014:

Name	Executive contributions in 2014 (1)	Registrant contributions in 2014 (2)	Aggregate earnings/(losses) in 2014	Aggregate withdrawals/ distributions	Aggregate balance as of December 31, 2014 (3)
Gregory E. Abel	$ —	$ —	$ —	$ —	$ —
A. Richard Walje	285,476	—	93,267	3,995	2,096,626
R. Patrick Reiten	—	—	34,975	—	496,244
Micheal G. Dunn	—	15,922	19,329	—	231,318
Douglas K. Stuver	—	—	640	—	10,515
Cindy A. Crane	187,287	—	128,835	—	1,317,473

(1) The executive contribution amount shown for Mr. Walje represents a deferral of $62,500 of his 2014 compensation and a portion of his 2010 LTIP award which was deferred in 2014. The $62,500 deferred compensation and $50,600 of the deferred LTIP award are included in the 2014 total compensation reported for him in the Summary Compensation Table and are not additional compensation. The remaining 2010 LTIP award amount was earned prior to 2014. The executive contribution amount shown for Ms. Crane represents a deferral of her 2010 LTIP award which was deferred in 2014. Of this amount, $50,986 is included in the 2014 total compensation reported for her in the Summary Compensation Table and is not additional compensation. The remaining amount was earned prior to 2014.

(2) The registrant contribution amount shown for Mr. Dunn is included in the 2014 total compensation reported for him in the Summary Compensation Table and is not additional earned compensation. The amount was earned in 2014 but not contributed into the DCP until 2015.

(3) The aggregate balance as of December 31, 2014 shown for Messrs. Walje and Dunn includes $95,759 and $50,647, respectively, of compensation previously reported in 2013 in the Summary Compensation Table and $206,219 and $46,382, respectively, of compensation previously reported in 2012 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 BHE's Annual Report on Form 10-K for the year ended December 31, 2014 (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, 2014 and are payable as lump sums unless otherwise noted.

Termination Scenario	Incentive (1)	Pension (2)
Gregory E. Abel:		
Retirement, Voluntary and Involuntary With or Without Cause	$ —	$ —
Death and Disability	—	—
A. Richard Walje (3):		
Retirement, Voluntary and Involuntary With or Without Cause	—	72,719
Death and Disability	1,245,717	72,719
R. Patrick Reiten:		
Retirement, Voluntary and Involuntary With or Without Cause	—	2,654
Death and Disability	1,310,378	2,654
Micheal G. Dunn:		
Retirement, Voluntary and Involuntary With or Without Cause	—	13,595
Death and Disability	1,278,687	13,595
Douglas K. Stuver:		
Retirement, Voluntary and Involuntary With or Without Cause	—	199
Death and Disability	536,126	199
Cindy A. Crane:		
Retirement, Voluntary and Involuntary With or Without Cause	—	—
Death and Disability	582,026	—

(1) Amounts represent the unvested portion of each NEO's LTIP account, which becomes 100% vested upon death or disability.

(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 2014 were employees of PacifiCorp, or in the case of Messrs. Anderson and Goodman, employees of BHE, 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 BHE's Annual Report on Form 10-K for the year ended December 31, 2014 (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 (3)	33,229	994,893	1,028,122
Patrick J. Goodman	—	—	—
Natalie L. Hocken	21,463	1,064,482	1,085,945
Mark C. Moench (4)	17,565	65,636	83,201

(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. Refer to the Pension Benefits table above for a discussion of the assumptions used in calculating these amounts. 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, 2014 that are required to be quantified are as follows:

(i) Base salary in the amounts of $312,667 for Mr. Gale, $229,500 for Ms. Hocken and $33,496 for Mr. Moench.

(ii) Contributions to our 401(k) Plan of $9,100 for Mr. Gale, $29,105 for Ms. Hocken and $1,306 for Mr. Moench.

(iii) Life insurance premium paid by us on behalf of Mr. Gale in the amount of $12,500.

(iv) A performance award in the amount of $150,000 for Ms. Hocken in recognition of efforts to support our objectives.

(v) Payout of accrued vacation upon retirement in the amounts of $39,090 for Mr. Gale and $30,334 for Mr. Moench.

(vi) Annual cash incentive awards earned pursuant to the AIP for our directors, the vesting of LTIP awards and associated vested earnings for Mr. Gale and Ms. Hocken. The breakout of AIP and LTIP awards for 2014 is as follows:

		LTIP		
	AIP	Vested Awards	Vested Earnings	Total
Brent E. Gale	$ 170,000	$ 316,400	$ 134,636	$ 451,036
Natalie L. Hocken	225,000	298,071	132,306	430,377

(3) Mr. Gale retired as a director and employee effective January 1, 2015.

(4) Mr. Moench retired as a director and employee effective February 2014.

Compensation Committee Interlocks and Insider Participation

Mr. Abel is our Chairman and CEO and also the Chairman, President and Chief Executive Officer of BHE. 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 BHE) 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 Berkshire Hathaway Energy Company, or BHE. Our common stock is indirectly owned by BHE, 666 Grand Avenue, Suite 500, Des Moines, Iowa 50309-2580. BHE is a consolidated subsidiary of Berkshire Hathaway Inc., or Berkshire Hathaway, that, as of February 18, 2015, owns 89.94% of BHE's common stock. The balance of BHE's common stock is owned by Walter Scott, Jr. (along with family members and related entities), a member of BHE'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 BHE'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 February 18, 2015:

	BHE		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)	740,961	0.96%	5	*	2,289	*
Douglas L. Anderson	—	—	4	*	300	*
Cindy A. Crane	—	—	—	—	—	—
Micheal G. Dunn	—	—	—	—	—	—
Patrick J. Goodman	—	—	5	*	796	*
Natalie L. Hocken	—	—	—	—	—	—
R. Patrick Reiten	—	—	—	—	—	—
Douglas K. Stuver	—	—	—	—	—	—
All executive officers and directors as a group (8 persons)	740,961	0.96%	14	*	3,385	*

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

(1) Includes shares of which the listed beneficial owner is deemed to have the right to acquire beneficial ownership under Rule 13d-3(d) under the Securities Exchange Act, including, among other things, shares which the listed beneficial owner has the right to acquire within 60 days.

(2) In accordance with a shareholders agreement, as amended on December 7, 2005, based on an assumed value for BHE's common stock and the closing price of Berkshire Hathaway common stock on February 18, 2015, Mr. Abel would be entitled to exchange his shares of BHE common stock for either 1,580 shares of Berkshire Hathaway Class A stock or 2,367,367 shares of Berkshire Hathaway Class B stock. Assuming an exchange of all available BHE 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 BHE 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 BHE'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 Berkshire Hathaway Energy Company, or BHE, 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 BHE and its other subsidiaries, the costs of certain administrative services provided by BHE to us or by us to BHE, or shared with BHE 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 BHE 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 BHE, our Board of Directors consists of BHE 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 BHE 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):

	2014	2013
Audit fees(1)	$ 1.5	$ 1.5
Audit-related fees(2)	0.2	0.2
Tax fees(3)	—	—
All other fees	—	—
Total	$ 1.7	$ 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 BHE 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 BHE. 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 BHE 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 BHE will be submitted to the audit committee of BHE by both PacifiCorp's independent auditor and BHE'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 BHE will be submitted to BHE's Chief Financial Officer and must include a detailed description of the services to be rendered. BHE'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 BHE. The audit committee of BHE will be informed on a timely basis of any such services rendered by the independent auditor.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) Financial Statements and Schedules

(i) Financial Statements:

Consolidated Financial Statements are included in Item 8.

(ii) Financial Statement Schedules:

All schedules have been omitted because they are either not applicable, not required or the information required to be set forth therein is included on the Consolidated Financial Statements or notes thereto.

(b) Exhibits

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

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

Not applicable.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized on this 27th day of February 2015.

PACIFICORP

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

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

Signature	Title	Date
/s/ Gregory E. Abel Gregory E. Abel	Chairman of the Board of Directors and Chief Executive Officer (principal executive officer)	February 27, 2015
/s/ Douglas K. Stuver Douglas K. Stuver	Senior Vice President and Chief Financial Officer (principal financial and accounting officer)	February 27, 2015
/s/ Douglas L. Anderson Douglas L. Anderson	Director	February 27, 2015
/s/ Micheal G. Dunn Micheal G. Dunn	Director	February 27, 2015
/s/ Patrick J. Goodman Patrick J. Goodman	Director	February 27, 2015
/s/ Natalie L. Hocken Natalie L. Hocken	Director	February 27, 2015
/s/ R. Patrick Reiten R. Patrick Reiten	Director	February 27, 2015

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., as successor Trustee, incorporated by reference to Exhibit 4-E, Form 8-B, File No. 1-5152, as supplemented and modified by 27 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
4.1	8-K	June 6, 2013	1-5152
4.1	8-K	March 13, 2014	1-5152

4.2* Third Restated Articles of Incorporation and Bylaws. See 3.1 and 3.2 above.

In reliance upon Item 601(b)(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 March 27, 2013, 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 May 3, 2013, File No. 1-5152).
10.7*	$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).
10.8*†	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).
10.9*†	Amendment No. 2 to the PacifiCorp Executive Voluntary Deferred Compensation Plan dated October 16, 2012. (Exhibit 10.11, Annual Report on Form 10-K, for the year ended December 31, 2012, filed March 1, 2013, File No. 1-5152).
10.10†	PacifiCorp Long-Term Incentive Partnership Plan effective January 1, 2014.
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, 2014 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 Shareholders' 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.

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, Gregory E. 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, Berkshire Hathaway Energy Company ("BHE") and is not directly compensated by PacifiCorp. PacifiCorp reimburses BHE for the cost of Mr. Abel's time spent on PacifiCorp matters, including compensation paid to him by BHE, pursuant to an intercompany administrative services agreement among BHE and its subsidiaries.

The named executive officers and employee 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 and employee directors 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 employee directors are participants in PacifiCorp's Long-Term Incentive Partnership Plan ("LTIP"). A copy of the LTIP is attached as Exhibit 10.10 to this Form 10-K.

Base salary for named executive officers and employee directors for PacifiCorp's fiscal year ending December 31, 2015 (excluding Mr. Abel) is shown in the following table:

Name and Title	Base Salary
Douglas K. Stuver Senior Vice President and Chief Financial Officer	$ 258,300
Cindy A. Crane President and Chief Executive Officer, Rocky Mountain Power	300,000
R. Patrick Reiten President and Chief Executive Officer, Pacific Power	330,000
Micheal G. Dunn President and Chief Executive Officer, PacifiCorp Energy	330,000
Natalie L. Hocken Director	234,090

Messrs. Reiten and Dunn 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 BHE, but do not receive additional compensation for their service as directors other than what they receive as employees of BHE.

EXHIBIT 12.1

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

	Years Ended December 31,				
	2014	2013	2012	2011	2010
Earnings Available for Fixed Charges:					
Income from continuing operations before income tax expense	$ 1,007	$ 979	$ 734	$ 768	$ 777
Fixed charges	384	385	385	397	392
Total earnings available for fixed charges	$ 1,391	$ 1,364	$ 1,119	$ 1,165	$ 1,169
Fixed Charges:					
Interest expense	$ 379	$ 379	$ 380	$ 392	$ 387
Estimated interest portion of rentals charged to expense	5	6	5	5	5
Total fixed charges	$ 384	$ 385	$ 385	$ 397	$ 392
Ratio of Earnings to Fixed Charges	3.6x	3.5x	2.9x	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,				
	2014	2013	2012	2011	2010
Earnings Available for Fixed Charges:					
Income from continuing operations before income tax expense	$ 1,007	$ 979	$ 734	$ 768	$ 777
Fixed charges	384	385	385	397	392
Total earnings available for fixed charges	$ 1,391	$ 1,364	$ 1,119	$ 1,165	$ 1,169
Fixed Charges and Preferred Stock Dividends:					
Interest expense	$ 379	$ 379	$ 380	$ 392	$ 387
Estimated interest portion of rentals charged to expense	5	6	5	5	5
Total fixed charges	384	385	385	397	392
Preferred stock dividends [1]	—	2	3	3	3
Total fixed charges and preferred stock dividends	$ 384	$ 387	$ 388	$ 400	$ 395
Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends	3.6x	3.5x	2.9x	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. 333-192267 on Form S-3ASR of our report dated February 27, 2015, 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, 2014.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 27, 2015

EXHIBIT 31.1

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

I, Gregory E. Abel, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: February 27, 2015

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

EXHIBIT 31.2

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

I, Douglas K. Stuver, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: February 27, 2015

/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, 2014 (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: February 27, 2015

/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, 2014 (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: February 27, 2015

/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, 2014 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, 2014. There were no mining-related fatalities during the year ended December 31, 2014. 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, 2014.

	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	—	—	—	—	$ 38	4	5	10
Bridger (surface)	3	—	2	—	—	8	3	3	4
Bridger (underground)	47	—	2	—	1	219	11	19	19
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 alleged unwarrantable failure (i.e., aggravated conduct constituting more than ordinary negligence) to comply with a mandatory health or safety standard.

(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. The imminent danger order under Section 107(a) of the Mine Safety Act at Bridger underground mine was reconsidered and subsequently vacated by MSHA.

(6) Amounts include 13 contests of proposed penalties under Subpart C, four contests of citations or orders under Subpart B and one labor-related complaint under Subpart E 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.