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, 2015

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.
001-14881	**BERKSHIRE HATHAWAY ENERGY COMPANY** **(An Iowa Corporation)** **666 Grand Avenue, Suite 500** **Des Moines, Iowa 50309-2580** **515-242-4300**	**94-2213782**
1-5152	**PACIFICORP** **(An Oregon Corporation)** **825 N.E. Multnomah Street** **Portland, Oregon 97232** **503-813-5645**	**93-0246090**
333-90553	**MIDAMERICAN FUNDING, LLC** **(An Iowa Limited Liability Company)** **666 Grand Avenue, Suite 500** **Des Moines, Iowa 50309-2580** **515-242-4300**	**47-0819200**
333-206980	**MIDAMERICAN ENERGY COMPANY** **(An Iowa Corporation)** **666 Grand Avenue, Suite 500** **Des Moines, Iowa 50309-2580** **515-242-4300**	**42-1425214**
000-52378	**NEVADA POWER COMPANY** **(A Nevada Corporation)** **6226 West Sahara Avenue** **Las Vegas, Nevada 89146** **702-402-5000**	**88-0420104**
000-00508	**SIERRA PACIFIC POWER COMPANY** **(A Nevada Corporation)** **6100 Neil Road** **Reno, Nevada 89511** **775-834-4011**	**88-0044418**

Registrant	Securities registered pursuant to Section 12(b) of the Act:
BERKSHIRE HATHAWAY ENERGY COMPANY	None
PACIFICORP	None
MIDAMERICAN FUNDING, LLC	None
MIDAMERICAN ENERGY COMPANY	None
NEVADA POWER COMPANY	None
SIERRA PACIFIC POWER COMPANY	None

Registrant	Securities registered pursuant to Section 12(g) of the Act:
BERKSHIRE HATHAWAY ENERGY COMPANY	None
PACIFICORP	None
MIDAMERICAN FUNDING, LLC	None
MIDAMERICAN ENERGY COMPANY	None
NEVADA POWER COMPANY	Common Stock, $1.00 stated value
SIERRA PACIFIC POWER COMPANY	Common Stock, $3.75 par value

Registrant	Name of exchange on which registered:
BERKSHIRE HATHAWAY ENERGY COMPANY	None
PACIFICORP	None
MIDAMERICAN FUNDING, LLC	None
MIDAMERICAN ENERGY COMPANY	None
NEVADA POWER COMPANY	None
SIERRA PACIFIC POWER COMPANY	None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Registrant	Yes	No
BERKSHIRE HATHAWAY ENERGY COMPANY		X
PACIFICORP		X
MIDAMERICAN FUNDING, LLC		X
MIDAMERICAN ENERGY COMPANY	X	
NEVADA POWER COMPANY		X
SIERRA PACIFIC POWER COMPANY		X

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Registrant	Yes	No
BERKSHIRE HATHAWAY ENERGY COMPANY		X
PACIFICORP		X
MIDAMERICAN FUNDING, LLC	X	
MIDAMERICAN ENERGY COMPANY		X
NEVADA POWER COMPANY		X
SIERRA PACIFIC POWER COMPANY		X

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Registrant	**Yes**	**No**
BERKSHIRE HATHAWAY ENERGY COMPANY	X	
PACIFICORP	X	
MIDAMERICAN FUNDING, LLC		X
MIDAMERICAN ENERGY COMPANY	X	
NEVADA POWER COMPANY	X	
SIERRA PACIFIC POWER COMPANY	X	

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web sites, 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 registrants were 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 registrants' 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.

Registrant	**Large Accelerated Filer**	**Accelerated filer**	**Non-accelerated Filer**	**Smaller Reporting Company**
BERKSHIRE HATHAWAY ENERGY COMPANY			X	
PACIFICORP			X	
MIDAMERICAN FUNDING, LLC			X	
MIDAMERICAN ENERGY COMPANY			X	
NEVADA POWER COMPANY			X	
SIERRA PACIFIC POWER COMPANY			X	

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

All shares of outstanding common stock of Berkshire Hathaway Energy Company are privately held by a limited group of investors. As of January 31, 2016, 77,391,144 shares of common stock, no par value, were outstanding.

All shares of outstanding common stock of PacifiCorp are indirectly owned by Berkshire Hathaway Energy Company. As of January 31, 2016, 357,060,915 shares of common stock, no par value, were outstanding.

All of the member's equity of MidAmerican Funding, LLC is held by its parent company, Berkshire Hathaway Energy Company, as of January 31, 2016.

All shares of outstanding common stock of MidAmerican Energy Company are owned by its parent company, MHC Inc., which is a direct, wholly owned subsidiary of MidAmerican Funding, LLC. As of January 31, 2016, 70,980,203 shares of MidAmerican Energy Company common stock, no par value, were outstanding.

All shares of outstanding common stock of Nevada Power Company are owned by its parent company, NV Energy, Inc., which is an indirect, wholly owned subsidiary of Berkshire Hathaway Energy Company. As of January 31, 2016, 1,000 shares of common stock, $1.00 stated value, were outstanding.

All shares of outstanding common stock of Sierra Pacific Power Company are owned by its parent company, NV Energy, Inc., which is an indirect, wholly owned subsidiary of Berkshire Hathaway Energy Company. As of January 31, 2016, 1,000 shares of common stock, $3.75 par value, were outstanding.

MidAmerican Funding, LLC, MidAmerican Energy Company, Nevada Power Company and Sierra Pacific Power Company meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and are therefore filing portions of this Form 10-K with the reduced disclosure format specified in General Instruction I(2) of Form 10-K.

This combined Form 10-K is separately filed by Berkshire Hathaway Energy Company, PacifiCorp, MidAmerican Funding, LLC, MidAmerican Energy Company, Nevada Power Company and Sierra Pacific Power Company. Information contained herein relating to any individual company is filed by such company on its own behalf. Each company makes no representation as to information relating to the other companies.

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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 Part III - Items 10 through 14, the following terms have the definitions indicated.

Entity Definitions	
BHE	Berkshire Hathaway Energy Company
Berkshire Hathaway Energy or the Company	Berkshire Hathaway Energy Company and its subsidiaries
PacifiCorp	PacifiCorp and its subsidiaries
MidAmerican Funding	MidAmerican Funding, LLC and its subsidiaries
MidAmerican Energy	MidAmerican Energy Company
NV Energy	NV Energy, Inc. and its subsidiaries
Nevada Power	Nevada Power Company and its subsidiaries
Sierra Pacific	Sierra Pacific Power Company and its subsidiaries
Nevada Utilities	Nevada Power Company and Sierra Pacific Power Company
Registrants	Berkshire Hathaway Energy, PacifiCorp, MidAmerican Energy, MidAmerican Funding, Nevada Power and Sierra Pacific
Subsidiary Registrants	PacifiCorp, MidAmerican Energy, MidAmerican Funding, Nevada Power and Sierra Pacific
Northern Powergrid	Northern Powergrid Holdings Company
Northern Natural Gas	Northern Natural Gas Company
Kern River	Kern River Gas Transmission Company
AltaLink	BHE Canada Holdings Corporation
ALP	AltaLink, L.P.
BHE U.S. Transmission	BHE U.S. Transmission, LLC
BHE Renewables, LLC	BHE Renewables, LLC
HomeServices	HomeServices of America, Inc. and its subsidiaries
BHE Pipeline Group or Pipeline Companies	Consists of Northern Natural Gas and Kern River
BHE Transmission	Consists of AltaLink and BHE U.S. Transmission
BHE Renewables	Consists of BHE Renewables, LLC and CalEnergy Philippines
ETT	Electric Transmission Texas, LLC
Domestic Regulated Businesses	PacifiCorp, MidAmerican Energy Company, Nevada Power Company, Sierra Pacific Power Company, Northern Natural Gas Company and Kern River Gas Transmission Company
Regulated Businesses	PacifiCorp, MidAmerican Energy Company, Nevada Power Company, Sierra Pacific Power Company, Northern Natural Gas Company, Kern River Gas Transmission Company and AltaLink, L.P.
Utilities	PacifiCorp, MidAmerican Energy Company, Nevada Power Company and Sierra Pacific Power Company
Northern Powergrid Distribution Companies	Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc
Berkshire Hathaway	Berkshire Hathaway Inc.
Topaz	Topaz Solar Farms LLC
Topaz Project	550-megawatt solar project in California
Agua Caliente	Agua Caliente Solar, LLC
Agua Caliente Project	290-megawatt solar project in Arizona
Bishop Hill II	Bishop Hill Energy II LLC
Bishop Hill Project	81-megawatt wind-powered generating facility in Illinois
Pinyon Pines I	Pinyon Pines Wind I, LLC

Pinyon Pines II	Pinyon Pines Wind II, LLC
Pinyon Pines Projects	168-megawatt and 132-megawatt wind-powered generating facilities in California
Jumbo Road	Jumbo Road Holdings, LLC
Jumbo Road Project	300-megawatt wind-powered generating facility in Texas
Solar Star Funding	Solar Star Funding, LLC
Solar Star Projects	A combined 586-megawatt solar project in California
Solar Star I	Solar Star California XIX, LLC
Solar Star II	Solar Star California XX, LLC

Certain Industry Terms

AESO	Alberta Electric System Operator
AFUDC	Allowance for Funds Used During Construction
AUC	Alberta Utilities Commission
Bcf	Billion cubic feet
BTER	Base Tariff Energy Rates
California ISO	California Independent System Operator Corporation
CPUC	California Public Utilities Commission
DEAA	Deferred Energy Accounting Adjustment
Dodd-Frank Reform Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
Dth	Decatherms
DSM	Demand-side Management
EBA	Energy Balancing Account
ECAC	Energy Cost Adjustment Clause
ECAM	Energy Cost Adjustment Mechanism
EEIR	Energy Efficiency Implementation Rate
EIM	Energy Imbalance Market
EPA	United States Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
GEMA	Gas and Electricity Markets Authority
GHG	Greenhouse Gases
GWh	Gigawatt Hours
ICC	Illinois Commerce Commission
IPUC	Idaho Public Utilities Commission
IRP	Integrated Resource Plan
IUB	Iowa Utilities Board
kV	Kilovolt
LNG	Liquefied Natural Gas
LDC	Local Distribution Company
MATS	Mercury and Air Toxics Standards
MISO	Midcontinent Independent System Operator, Inc.
MW	Megawatts
MWh	Megawatt Hours
NERC	North American Electric Reliability Corporation
NRC	Nuclear Regulatory Commission
OCA	Iowa Office of Consumer Advocate
OPUC	Oregon Public Utility Commission

PCAM	Power Cost Adjustment Mechanism
PTAM	Post Test-year Adjustment Mechanism
PUCN	Public Utilities Commission of Nevada
RCRA	Resource Conservation and Recovery Act
REC	Renewable Energy Credit
RPS	Renewable Portfolio Standards
RRA	Renewable Energy Credit and Sulfur Dioxide Revenue Adjustment Mechanism
RTO	Regional Transmission Organization
SEC	United States Securities and Exchange Commission
SIP	State Implementation Plan
TAM	Transition Adjustment Mechanism
UPSC	Utah Public Service Commission
WECC	Western Electricity Coordinating Council
WPSC	Wyoming Public Service Commission
WUTC	Washington Utilities and Transportation Commission

Forward-Looking Statements

This report contains statements that do not directly or exclusively relate to historical facts. These statements are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, 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 the relevant Registrant'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 each Registrant 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 the Registrants' 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 facility output, accelerate facility retirements or delay facility construction or acquisition;
- the outcome of rate cases and other proceedings conducted by regulatory commissions or other governmental and legal bodies and the Registrants' ability to recover costs through rates in a timely manner;
- changes in economic, industry, competition 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 and natural gas supply or the Registrants' ability to obtain long-term contracts with customers and suppliers;
- performance, availability and ongoing operation of the Registrants' facilities, including facilities not operated by the Registrants, due to the impacts of market conditions, outages and repairs, transmission constraints, weather, including wind, solar and hydroelectric conditions, and operating conditions;
- a high degree of variance between actual and forecasted load or generation that could impact the Registrants' hedging strategy and the cost of balancing its generation resources with its retail load obligations;
- 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;
- the financial condition and creditworthiness of the Registrants' 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 the Registrants' credit facilities;
- changes in the Registrant's respective credit ratings;
- risks relating to nuclear generation, including unique operational, closure and decommissioning risks;
- hydroelectric conditions and the cost, feasibility and eventual outcome of hydroelectric relicensing proceedings;
- 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 the ability of the respective Registrants to recover such costs in regulated rates;
- fluctuations in foreign currency exchange rates, primarily the British pound and the Canadian dollar;
- increases in employee healthcare costs;
- the impact of investment performance and changes in interest rates, legislation, healthcare cost trends, mortality and morbidity on pension and other postretirement benefits expense and funding requirements;
- changes in the residential real estate brokerage and mortgage industries and regulations that could affect brokerage and mortgage transactions;
- unanticipated construction delays, changes in costs, receipt of required permits and authorizations, ability to fund capital projects and other factors that could affect future facilities and infrastructure additions;

- the availability and price of natural gas in applicable geographic regions and demand for natural gas supply;
- the impact of new accounting guidance or changes in current accounting estimates and assumptions on the consolidated financial results of the respective Registrants;
- the ability to successfully integrate future acquired operations into its business;
- the effects of catastrophic and other unforeseen events, which may be caused by factors beyond the control of each respective Registrant or by a breakdown or failure of the Registrants' operating assets, including storms, floods, fires, earthquakes, explosions, landslides, mining accidents, litigation, wars, terrorism, and embargoes; and
- other business or investment considerations that may be disclosed from time to time in the Registrants' filings with the SEC or in other publicly disseminated written documents.

Further details of the potential risks and uncertainties affecting the Registrants are described in Item 1A and other discussions contained in this Form 10-K. Each Registrant 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

BHE is a holding company that owns subsidiaries principally engaged in energy businesses and is a consolidated subsidiary of Berkshire Hathaway. As of January 31, 2016, Berkshire Hathaway, Mr. Walter Scott, Jr., a member of BHE's Board of Directors (along with family members and related entities) and Mr. Gregory E. Abel, BHE's Chairman, President and Chief Executive Officer, owned 89.9%, 9.1% and 1.0%, respectively, of BHE's voting common stock.

Berkshire Hathaway Energy's operations are organized and managed as eight business segments: PacifiCorp, MidAmerican Funding (which primarily consists of MidAmerican Energy), NV Energy (which primarily consists of Nevada Power and Sierra Pacific), Northern Powergrid (which primarily consists of Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc), BHE Pipeline Group (which consists of Northern Natural Gas and Kern River), BHE Transmission (which consists of AltaLink and BHE U.S. Transmission), BHE Renewables and HomeServices. BHE, through these businesses, owns four utility companies in the United States serving customers in 11 states, two electricity distribution companies in Great Britain, two interstate natural gas pipeline companies in the United States, an electric transmission business in Canada, interests in electric transmission businesses in the United States, a renewable energy business primarily selling power generated from solar, wind, geothermal and hydroelectric sources under long-term contracts, the second largest residential real estate brokerage firm in the United States and one of the largest residential real estate brokerage franchise networks in the United States.

BHE owns a highly diversified portfolio of primarily regulated businesses that generate, transmit, store, distribute and supply energy and serve customers across geographically diverse service territories in the Western and Midwestern United States, in Great Britain and Canada.

- 91% of Berkshire Hathaway Energy's consolidated operating income during 2015 was generated from rate-regulated businesses.
- As of December 31, 2015, the Utilities served 4.7 million electric and natural gas customers in 11 states in the United States, Northern Powergrid served 3.9 million end-users in northern England and ALP served approximately 85% of Alberta, Canada's population.
- As of December 31, 2015, Berkshire Hathaway Energy owned approximately 29,900 MW of generation in operation and under construction:
  - Approximately 26,000 MW of generation is owned by its regulated electric utility businesses;
  - Approximately 3,900 MW of generation is owned by its nonregulated subsidiaries, the majority of which provides power to utilities under long-term contracts; and
  - Berkshire Hathaway Energy's generation capacity in operation and under construction includes 35% natural gas, 33% coal, 25% wind and solar, 4% hydroelectric and 3% nuclear and other.
- As of December 31, 2015, Berkshire Hathaway Energy has invested $16 billion in solar, wind, geothermal and biomass generation and owns 7% of the wind generation and 6% of the solar generation in the United States.
- Berkshire Hathaway Energy owns approximately 32,700 miles of transmission lines and owns a 50% interest in ETT that has 1,000 miles of transmission lines.
- The BHE Pipeline Group owns approximately 16,400 miles of pipeline with a design capacity of approximately 7.8 Bcf of natural gas per day and transported approximately 7% of the total natural gas consumed in the United States during 2015.
- HomeServices closed over $77.6 billion of home sales in 2015, up 9.0% from 2014, with over 26,000 sales associates and continued to grow its brokerage, mortgage and franchise businesses. HomeServices' franchise business operates in 48 states with over 400 franchisees throughout the country.

As of December 31, 2015, Berkshire Hathaway Energy had approximately 21,000 employees, of which approximately 8,600 are covered by union contracts. The majority of the union employees are employed by the Utilities and are represented by the International Brotherhood of Electrical Workers, the Utility Workers Union of America, the United Utility Workers Association and the International Brotherhood of Boilermakers. These collective bargaining agreements have expiration dates ranging through June 2021. HomeServices' approximately 26,000 sales associates are independent contractors and not employees.

Refer to Note 21 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K for additional reportable segment information.

BHE's principal executive offices are located at 666 Grand Avenue, Suite 500, Des Moines, Iowa 50309-2580 and its telephone number is (515) 242-4300. BHE was initially incorporated in 1971 as California Energy Company, Inc. under the laws of the state of Delaware and through a merger transaction in 1999 was reincorporated in Iowa under the name MidAmerican Energy Holdings Company. In 2014, its name was changed to Berkshire Hathaway Energy Company.

PACIFICORP

General

PacifiCorp, an indirect wholly owned subsidiary of BHE, is a United States regulated electric utility company headquartered in Oregon that serves 1.8 million retail electric customers in portions of Utah, Oregon, Wyoming, Washington, Idaho and California. PacifiCorp is principally engaged in the business of generating, transmitting, distributing and selling electricity. PacifiCorp's combined service territory covers approximately 143,000 square miles and includes diverse regional economies across six states. 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. In addition to retail sales, PacifiCorp 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's subsidiaries support its electric utility operations by providing coal mining services.

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 27 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. In return, the state utility commissions have established rates on a cost-of-service basis, which are designed to allow PacifiCorp an opportunity to recover its costs of providing services and to earn a reasonable return on its investments.

PacifiCorp's principal executive offices are located at 825 N.E. Multnomah Street, Portland, Oregon 97232, and its telephone number is (503) 813-5645. 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. 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.

BHE controls substantially all of PacifiCorp's voting securities, which include both common and preferred stock.

Regulated Electric Operations

Customers

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

	2015		2014		2013	
Utah	24,158	44%	24,105	44%	24,510	44%
Oregon	12,863	24	12,959	24	13,090	24
Wyoming	9,330	17	9,568	17	9,554	17
Washington	4,108	8	4,118	8	4,093	7
Idaho	3,443	6	3,495	6	3,621	7
California	739	1	754	1	795	1
	54,641	100%	54,999	100%	55,663	100%

Electricity sold to PacifiCorp's retail and wholesale customers by class of customer and the average number of retail customers for the years ended December 31 were as follows:

	2015		2014		2013	
GWh sold:						
Residential	15,566	25%	15,568	24%	16,339	25%
Commercial	17,262	27	17,073	26	17,057	26
Industrial and irrigation	21,403	34	21,934	34	21,832	33
Other	410	—	424	—	435	1
Total retail	54,641	86	54,999	84	55,663	85
Wholesale	8,889	14	10,270	16	10,206	15
Total GWh sold	63,530	100%	65,269	100%	65,869	100%
Average number of retail customers (in thousands):						
Residential	1,574	87%	1,546	87%	1,522	86%
Commercial	202	11	200	11	208	12
Industrial and irrigation	33	2	33	2	34	2
Other	4	—	4	—	3	—
Total	1,813	100%	1,783	100%	1,767	100%
Retail customers:						
Average usage per customer (kilowatt hours)	30,139		30,846		31,501	
Average revenue per customer	$ 2,652		$ 2,645		$ 2,627	
Revenue per kilowatt hour	8.8¢		8.6¢		8.3¢	

Changes in economic and weather conditions, as well as various conservation, energy efficiency and customer self-generation measures and programs, impact PacifiCorp's 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 2015, PacifiCorp's peak demand was 10,621 MW in the summer and 8,550 MW in the winter.

Generating Facilities and Fuel Supply

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, 2015:

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	637	637
Cholla No. 4	Joseph City, AZ	Coal	1981	395	395
Wyodak No. 1	Gillette, WY	Coal	1978	332	266
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
				9,300	5,931
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:[3]					
Lewis River System	WA	Hydroelectric	1931-1958	578	578
North Umpqua River System	OR	Hydroelectric	1950-1956	204	204
Klamath River System	CA, OR	Hydroelectric	1903-1962	170	170
Bear River System	ID, UT	Hydroelectric	1908-1984	105	105
Rogue River System	OR	Hydroelectric	1912-1957	52	52
Minor hydroelectric facilities	Various	Hydroelectric	1895-1986	26	26
				1,135	1,135
WIND:[3]					
Marengo	Dayton, WA	Wind	2007-2008	210	210
Glenrock	Glenrock, WY	Wind	2008-2009	138	138
Seven Mile Hill	Medicine Bow, WY	Wind	2008	119	119
Dunlap Ranch	Medicine Bow, WY	Wind	2010	111	111
Leaning Juniper	Arlington, OR	Wind	2006	100	100
High Plains	McFadden, WY	Wind	2009	99	99
Rolling Hills	Glenrock, WY	Wind	2009	99	99
Goodnoe Hills	Goldendale, WA	Wind	2008	94	94
Foote Creek	Arlington, WY	Wind	1999	41	32
McFadden Ridge	McFadden, WY	Wind	2009	28	28
				1,039	1,030
OTHER:[3]					
Blundell	Milford, UT	Geothermal	1984, 2007	32	32
				32	32
Total Available Generating Capacity				14,502	10,894

(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 (in MW) under specified conditions. Net Owned Capacity indicates PacifiCorp's ownership of Facility Net Capacity.

(2) PacifiCorp currently plans to close or convert Naughton Unit No. 3 (280 MW) to a natural gas-fueled unit in 2018. Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for further discussion.

(3) 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.

Carbon Unit Nos. 1 and 2, a 172 MW coal-fueled generating facility, ("Carbon Facility") was idled in April 2015 and retired in December 2015. Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for further discussion.

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

	2015	2014	2013
Coal	61%	60%	62%
Natural gas	14	16	12
Hydroelectric(1)	4	5	4
Wind and other(1)	4	5	5
Total energy generated	83	86	83
Energy purchased - short-term contracts and other	9	6	9
Energy purchased - long-term contracts (renewable)(1)	5	5	5
Energy purchased - long-term contracts (non-renewable)	3	3	3
	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.

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 PacifiCorp's Item 7A in this Form 10-K for a discussion of commodity price risk and derivative contracts.

Coal

PacifiCorp has interests in coal mines that support its coal-fueled generating facilities and operates the Bridger surface and Bridger underground coal mines. In 2015, PacifiCorp idled the Deer Creek underground coal mine that historically served the Huntington, Hunter and Carbon generating facilities and commenced reclamation activities. These mines supplied 18%, 27% and 31% of PacifiCorp's total coal requirements during the years ended December 31, 2015, 2014 and 2013, respectively. The remaining coal requirements are acquired through long- and short-term third-party contracts. PacifiCorp also operates the Wyodak Coal Crushing Facility. PacifiCorp sold the Cottonwood Preparatory Plant and the Fossil Rock coal reserves to a third party in June 2015. Refer to "Regulatory Matters" in Item 1 of this Form 10-K for further discussion of these transactions and the Deer Creek mine closure.

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. PacifiCorp's recoverable coal reserves of operating mines as of December 31, 2015, 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	33	(1)
Bridger	Rock Springs, WY	Jim Bridger	Underground	34	(1)
Trapper	Craig, CO	Craig	Surface	5	(2)
				72	

(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.

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 99% of the net capacity of this portfolio through 15 individual licenses, which have terms of 30 to 50 years. The licenses for major hydroelectric generating facilities expire at various dates from December 2018 through May 2058. 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 16 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K and Note 13 of the Notes to Consolidated Financial Statements of PacifiCorp 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. 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 transmission and distribution systems included approximately 16,500 miles of transmission lines, 64,000 miles of distribution lines and 900 substations as of December 31, 2015.

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.

PacifiCorp and the California ISO implemented an EIM in November 2014. The EIM expands the real-time component of the California ISO to optimize and balance electricity supply and demand every five minutes across the entire PacifiCorp and California ISO EIM 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 EIM footprint every five minutes. In addition to generation resource bids, the California ISO market operator also receives continuous real-time updates of the 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.

In April 2015, PacifiCorp and the California ISO entered into a non-binding memorandum of understanding to explore the feasibility, costs and benefits of PacifiCorp joining a regional ISO as a participating transmission owner if the California ISO becomes a regional ISO by modifying its governance structure and expanding its balancing authority area. A comprehensive benefits study was completed and results were publicly announced in October 2015, along with an extension of the non-binding memorandum of understanding. The benefits study demonstrated gross benefits for customers exist, warranting further exploration and analysis of integration. PacifiCorp and the California ISO have initiated a stakeholder input and review process. If PacifiCorp decides to become a participating transmission owner in the regional ISO, it will seek necessary regulatory approvals, including from its state regulatory commissions and the FERC. Joining the regional ISO would extend PacifiCorp's current participation in the real-time market through the EIM to participation in the day-ahead energy market operated by the California ISO, in addition to unified planning and operation of PacifiCorp's transmission network.

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 between the Sigurd Substation in central Utah and the Red Butte Substation in southwest Utah 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 evaluated to ensure optimal benefits and timing before committing to move forward with permitting and construction. Through December 31, 2015, $1.8 billion had been spent and $1.6 billion, including AFUDC, had been placed in-service.

Future Generation, Conservation and Energy Efficiency

Integrated Resource Plan

As required by certain state regulations, PacifiCorp uses an IRP to develop a long-term resource plan to ensure that PacifiCorp can continue 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, accounting for planning uncertainty, risks, reliability, state energy policies and other factors. The IRP is prepared following a public process, which provides an opportunity for stakeholders to participate in PacifiCorp's resource planning process. PacifiCorp files its IRP on a biennial basis with the state commissions in each of the six states where PacifiCorp operates. Five states indicate whether the IRP meets the state commission's IRP standards and guidelines, a process referred to as "acknowledgment" in some states. PacifiCorp filed its 2015 IRP with the state commissions in March 2015. To date, the WPSC accepted the 2015 IRP into its files and the UPSC, IPUC and WUTC acknowledged the 2015 IRP. PacifiCorp is awaiting acknowledgment of the 2015 IRP from the OPUC.

Requests for Proposals

PacifiCorp issues individual Requests for Proposals ("RFPs"), each of which typically focuses on a specific category of generation resources consistent with the IRP or other customer-driven demands. 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.

Utah Subscriber Solar Program

In October 2015, the UPSC approved the Utah Subscriber Solar Program that allows Utah customers to meet a portion or all of their energy requirements from Utah-based solar photovoltaic resources. The program is an alternative for customers who are unable or do not want to install solar. Residential and small commercial participants will be able to subscribe in 200 kilowatt-hour blocks up to their total annual usage. Large commercial and industrial participants will be able to subscribe in 1 kilowatt blocks up to their total annual usage. As part of the program, PacifiCorp issued a 2015 Solar RFP to seek solar photovoltaic resources up to 20 MW sited in Utah. The contract for the solar resource was executed in January 2016 and the project is expected to be operational in December 2016. PacifiCorp is targeting the summer of 2016 for open enrollment in the program to begin.

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 energy project management, efficient building operations and 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 2015, PacifiCorp spent $134 million on these DSM programs, resulting in an estimated 641,486 MWh of first-year energy savings and an estimated 269 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 are captured in the retail rate agreements with those customers approved by their respective state commissions or through PacifiCorp's general rate case process.

Employees

As of December 31, 2015, PacifiCorp had approximately 5,700 employees, of which approximately 3,300 were covered by union contracts, principally with the International Brotherhood of Electrical Workers, the Utility Workers Union of America and the International Brotherhood of Boilermakers.

MIDAMERICAN FUNDING AND MIDAMERICAN ENERGY

MidAmerican Funding is an Iowa limited liability company whose sole member is BHE. MidAmerican Funding, a holding company, owns all of the outstanding common stock of MHC, which is a holding company owning all of the common stock of MidAmerican Energy; Midwest Capital Group, Inc. ("Midwest Capital"); and MEC Construction Services Co. ("MEC Construction"). MidAmerican Energy is a public utility company headquartered in Des Moines, Iowa, and incorporated in the state of Iowa. MHC, MidAmerican Funding and BHE are also headquartered in Des Moines, Iowa.

MidAmerican Funding and MHC

MidAmerican Funding conducts no business other than activities related to its debt securities and the ownership of MHC. MHC conducts no business other than the ownership of its subsidiaries and related corporate services. MHC's interests include 100% of the common stock of MidAmerican Energy, Midwest Capital and MEC Construction. MidAmerican Energy accounts for the predominant part of MidAmerican Funding's and MHC's assets, revenue and earnings. Financial information on MidAmerican Funding's segments of business is in Note 20 of the Notes to Consolidated Financial Statements of MidAmerican Funding in Item 8 of this Form 10-K.

MidAmerican Energy

General

MidAmerican Energy, an indirect wholly owned subsidiary of BHE, is a United States regulated electric and natural gas utility company headquartered in Iowa that serves 0.8 million regulated retail electric customers in portions of Iowa, Illinois and South Dakota and 0.7 million regulated retail and transportation natural gas customers in portions of Iowa, South Dakota, Illinois and Nebraska. MidAmerican Energy is principally engaged in the business of generating, transmitting, distributing and selling electricity and in distributing, selling and transporting natural gas. MidAmerican Energy's service territory covers approximately 11,000 square miles. Metropolitan areas in which MidAmerican Energy distributes electricity at retail include Council Bluffs, Des Moines, Fort Dodge, Iowa City, Sioux City and Waterloo, Iowa; and the Quad Cities (Davenport and Bettendorf, Iowa and Rock Island, Moline and East Moline, Illinois). Metropolitan areas in which it distributes natural gas at retail include Cedar Rapids, Des Moines, Fort Dodge, Iowa City, Sioux City and Waterloo, Iowa; the Quad Cities; and Sioux Falls, South Dakota. MidAmerican has a diverse customer base consisting of urban and rural residential customers and a variety of commercial and industrial customers. Principal industries served by MidAmerican Energy include processing and sales of food products; manufacturing, processing and fabrication of primary metals; farm and other non-electrical machinery; real estate; electronic data storage; cement and gypsum products; and government. In addition to retail sales and natural gas transportation, MidAmerican Energy sells electricity principally to markets operated by RTOs and natural gas to other utilities and market participants on a wholesale basis. MidAmerican Energy is a transmission-owning member of the MISO and participates in its energy and ancillary services markets.

MidAmerican Energy's regulated electric and natural gas operations are conducted under numerous franchise agreements, certificates, permits and licenses obtained from federal, state and local authorities. The franchise agreements, with various expiration dates, are typically for 20- to 25-year terms. Several of these franchise agreements give either party the right to seek amendment to the franchise agreement at one or two specified times during the term. MidAmerican Energy generally has an exclusive right to serve electric customers within its service territories and, in turn, has an obligation to provide electricity service to those customers. In return, the state utility commissions have established rates on a cost-of-service basis, which are designed to allow MidAmerican Energy an opportunity to recover its costs of providing services and to earn a reasonable return on its investment. In Illinois, MidAmerican Energy's regulated retail electric customers may choose their energy supplier.

MidAmerican Energy also has nonregulated business activities consisting predominantly of competitive electricity and natural gas.

MidAmerican Energy had total assets of $14.4 billion as of December 31, 2015, and total operating revenue of $3.4 billion for 2015. Financial information on MidAmerican Energy's segments of business is disclosed in MidAmerican Energy's Note 20 of Notes to Financial Statements in Item 8 of this Form 10-K.

The percentages of MidAmerican Energy's operating revenue and net income derived from the following business activities for the years ended December 31 were as follows:

	2015	2014	2013
Operating revenue:			
Regulated electric	54%	48%	52%
Regulated gas	19	27	24
Nonregulated	27	25	24
	100%	100%	100%
Net income:			
Regulated electric	89%	86%	84%
Regulated gas	7	10	12
Nonregulated	4	4	4
	100%	100%	100%

Regulated Electric Operations

Customers

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

	2015		2014		2013	
Iowa	20,922	91%	20,585	90%	20,217	90%
Illinois	1,903	8	1,975	9	2,015	9
South Dakota	217	1	217	1	220	1
	23,042	100%	22,777	100%	22,452	100%

Electricity sold to MidAmerican Energy's retail and wholesale customers by class of customer and the average number of retail customers for the years ended December 31 were as follows:

	2015		2014		2013	
GWh sold:						
Residential	6,166	19%	6,429	20%	6,572	20%
Commercial	3,806	12	4,084	12	4,265	13
Industrial	11,487	36	10,642	33	10,001	31
Other	1,583	5	1,622	5	1,614	5
Total retail	23,042	72	22,777	70	22,452	69
Wholesale	8,741	28	9,716	30	10,226	31
Total GWh sold	31,783	100%	32,493	100%	32,678	100%
Average number of retail customers (in thousands):						
Residential	646	86%	643	86%	637	86%
Commercial	90	12	87	12	86	12
Industrial	2	—	2	—	2	—
Other	14	2	14	2	14	2
Total	752	100%	746	100%	739	100%

In addition to the variations in weather from year to year, fluctuations in economic conditions within MidAmerican Energy's service territory and elsewhere can impact customer usage, particularly for industrial and wholesale customers. Wholesale sales are impacted by market prices for energy relative to the incremental cost to generate power.

There are seasonal variations in MidAmerican Energy's electricity sales that are principally related to weather and the related use of electricity for air conditioning. Additionally, electricity sales are priced higher in the summer months compared to the remaining months of the year. As a result, approximately 40% of MidAmerican Energy's regulated electric revenue is reported in the months of June, July, August and September.

The annual hourly peak demand on MidAmerican Energy's electric system usually occurs as a result of air conditioning use during the cooling season. Peak demand represents the highest demand on a given day and at a given hour. On July 17, 2015, retail customer usage of electricity caused an hourly peak demand of 4,624 MW on MidAmerican Energy's electric distribution system, which is 128 MW less than the record hourly peak demand of 4,752 MW set July 19, 2011.

Generating Facilities and Fuel Supply

MidAmerican Energy has ownership interest in a diverse portfolio of generating facilities. The following table presents certain information regarding MidAmerican Energy's owned generating facilities as of December 31, 2015:

Generating Facility	Location	Energy Source	Year Installed	Facility Net Capacity (MW)[1]	Net Owned Capacity (MW)[1]
WIND:					
Adair	Adair, IA	Wind	2008	175	175
Adams	Lennox, IA	Wind	2015	106	106
Carroll	Carroll, IA	Wind	2008	150	150
Century	Blairsburg, IA	Wind	2005-2008	200	200
Charles City	Charles City, IA	Wind	2008	75	75
Eclipse	Adair, IA	Wind	2012	200	200
Highland	Primghar, IA	Wind	2015	475	475
Intrepid	Schaller, IA	Wind	2004-2005	176	176
Laurel	Laurel, IA	Wind	2011	120	120
Lundgren	Otho, IA	Wind	2014	250	250
Macksburg	Macksburg, IA	Wind	2014	119	119
Morning Light	Adair, IA	Wind	2012	100	100
Pomeroy	Pomeroy, IA	Wind	2007-2011	286	286
Rolling Hills	Massena, IA	Wind	2011	443	443
Victory	Westside, IA	Wind	2006	99	99
Vienna	Marshalltown, IA	Wind	2012-2013	150	150
Walnut	Walnut, IA	Wind	2008	150	150
Wellsburg	Wellsburg, IA	Wind	2014	139	139
				3,413	3,413
COAL:					
George Neal Unit No. 1[2]	Sergeant Bluff, IA	Coal	1964	142	142
George Neal Unit No. 2[2]	Sergeant Bluff, IA	Coal	1972	248	248
George Neal Unit No. 3	Sergeant Bluff, IA	Coal	1975	514	370
George Neal Unit No. 4	Salix, IA	Coal	1979	644	262
Louisa	Muscatine, IA	Coal	1983	740	651
Ottumwa	Ottumwa, IA	Coal	1981	730	380
Walter Scott, Jr. Unit No. 3	Council Bluffs, IA	Coal	1978	701	554
Walter Scott, Jr. Unit No. 4	Council Bluffs, IA	Coal	2007	816	487
				4,535	3,094
NATURAL GAS AND OTHER:					
Greater Des Moines	Pleasant Hill, IA	Gas	2003-2004	486	486
Coralville	Coralville, IA	Gas	1970	66	66
Electrifarm	Waterloo, IA	Gas or Oil	1975-1978	190	190
Moline	Moline, IL	Gas	1970	64	64
Parr	Charles City, IA	Gas	1969	33	33
Pleasant Hill	Pleasant Hill, IA	Gas or Oil	1990-1994	160	160
River Hills	Des Moines, IA	Gas	1966-1967	118	118
Riverside Unit No. 5[3]	Bettendorf, IA	Gas	1961	128	128
Sycamore	Johnston, IA	Gas or Oil	1974	147	147
28 portable power modules	Various	Oil	2000	56	56
				1,448	1,448
NUCLEAR:					
Quad Cities Unit Nos. 1 and 2	Cordova, IL	Uranium	1972	1,824	456
HYDROELECTRIC:					
Moline Unit Nos. 1-4[4]	Moline, IL	Hydroelectric	1941	2	2
Total Available Generating Capacity				11,222	8,413
PROJECTS UNDER CONSTRUCTION					
Various wind projects				594	594
				11,816	9,007

(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 (in MW) under specified conditions. Net Owned Capacity indicates MidAmerican Energy's ownership of Facility Net Capacity.

(2) MidAmerican Energy currently anticipates retiring George Neal Unit Nos. 1 and 2 by April 15, 2016.

(3) Effective March 31, 2015, MidAmerican Energy limited Riverside Unit No. 5, previously a coal-fueled generating facility, to natural gas combustion.

(4) Three of the Moline hydroelectric units were out of service and not accredited by the MISO in 2015.

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

	2015	2014	2013
Coal	48%	55%	55%
Nuclear	12	12	12
Natural gas	1	—	1
Wind and other[1]	29	24	22
Total energy generated	90	91	90
Energy purchased - short-term contracts and other	8	7	9
Energy purchased - long-term contracts (renewable)[1]	1	1	—
Energy purchased - long-term contracts (non-renewable)	1	1	1
	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 renewable energy credits or other environmental commodities, or (c) excluded from energy purchased.

MidAmerican Energy is required to have resources available to continuously meet its customer needs. The percentage of MidAmerican Energy'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. When factors for one energy source are less favorable, MidAmerican Energy must place more reliance on other energy sources. For example, MidAmerican Energy can generate more electricity using its low cost wind-powered generating facilities when factors associated with these facilities are favorable. When factors associated with wind resources are less favorable, MidAmerican Energy must increase its reliance on more expensive generation or purchased electricity. MidAmerican Energy manages certain risks relating to its supply of electricity and fuel requirements by entering into various contracts, which may be accounted for as derivatives, which may include forwards, futures, 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 MidAmerican Energy's Item 7A in this Form 10-K for a discussion of commodity price risk and derivative contracts.

All of the coal-fueled generating facilities operated by MidAmerican Energy are fueled by low-sulfur, western coal from the Powder River Basin in northeast Wyoming. MidAmerican Energy's coal supply portfolio includes multiple suppliers and mines under short-term and multi-year agreements of varying terms and quantities through 2019. MidAmerican Energy believes supplies from these sources are presently adequate and available to meet MidAmerican Energy's needs. MidAmerican Energy's coal supply portfolio has substantially all of its expected 2016 requirements under fixed-price contracts. MidAmerican Energy regularly monitors the western coal market for opportunities to enhance its coal supply portfolio.

MidAmerican Energy has a multi-year long-haul coal transportation agreement with BNSF Railway Company ("BNSF"), an affiliate company, for the delivery of coal to all of the MidAmerican Energy-operated coal-fueled generating facilities other than the George Neal Energy Center. Under this agreement, BNSF delivers coal directly to MidAmerican Energy's Walter Scott, Jr. Energy Center and to an interchange point with Canadian Pacific Railway Company for short-haul delivery to the Louisa Energy Center. MidAmerican Energy has a multi-year long-haul coal transportation agreement with Union Pacific Railroad Company for the delivery of coal to the George Neal Energy Center.

MidAmerican Energy is a 25% joint owner of Quad Cities Generating Station Units 1 and 2 ("Quad Cities Station"), a nuclear power plant. Exelon Generation Company, LLC, a subsidiary of Exelon Corporation ("Exelon Generation"), is the 75% joint owner and the operator of Quad Cities Station. Approximately one-third of the nuclear fuel assemblies in each reactor core at Quad Cities Station is replaced every 24 months. MidAmerican Energy has been advised by Exelon Generation that the following requirements for Quad Cities Station can be met under existing supplies or commitments: uranium requirements through 2020 and partial requirements through 2022; uranium conversion requirements through 2022 and partial requirements through 2025; enrichment requirements through 2019 and partial requirements through 2025; and fuel fabrication requirements through 2022. MidAmerican Energy has been advised by Exelon Generation that it does not anticipate it will have difficulty in contracting for uranium, uranium conversion, enrichment or fabrication of nuclear fuel needed to operate Quad Cities Station during these time periods.

MidAmerican Energy uses natural gas and oil as fuel for intermediate and peak demand electric generation, igniter fuel, transmission support and standby purposes. These sources are presently in adequate supply and available to meet MidAmerican Energy's needs.

MidAmerican Energy owns more wind-powered generating capacity than any other United States rate-regulated electric utility and believes wind-powered generation offers a viable, economical and environmentally prudent means of supplying electricity and complying with laws and regulations. Pursuant to ratemaking principles approved by the IUB, all of MidAmerican Energy's wind-powered generating facilities in-service at December 31, 2015 are authorized to earn a fixed rate of return on equity over their useful lives ranging from 11.35% to 12.2% in any future Iowa rate proceeding. MidAmerican Energy'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 MidAmerican Energy's wind-powered generating facilities currently in-service, began expiring in 2014, with final expiration in 2025.

MidAmerican Energy sells and purchases electricity and ancillary services related to its generation and load in wholesale markets pursuant to the tariffs in those markets. MidAmerican Energy participates predominantly in the MISO energy and ancillary service markets, which provide MidAmerican Energy with wholesale opportunities over a large market area. MidAmerican Energy can enter into wholesale bilateral transactions in addition to market activity related to its assets. MidAmerican Energy is authorized to participate in the Southwest Power Pool, Inc. and PJM Interconnection, L.L.C. ("PJM") markets and can contract with several other major transmission-owning utilities in the region. MidAmerican Energy can utilize both financial swaps and physical fixed-price electricity sales and purchases contracts to reduce its exposure to electricity price volatility.

MidAmerican Energy's total net generating capability accredited by the MISO for the summer of 2015 was 5,406 MW compared to a 2015 summer peak demand of 4,624 MW. Accredited net generating capability represents the amount of generation available to meet the requirements of MidAmerican Energy's retail customers and consists of MidAmerican Energy-owned generation, certain customer "behind the meter" generators and the net amount of capacity purchases and sales. Accredited capacity may vary from the nominal, or design, capacity ratings, particularly for wind turbines whose output is dependent upon wind levels at any given time. Additionally, the actual amount of generating capacity available at any time may be less than the accredited capacity due to regulatory restrictions, transmission constraints, fuel restrictions and generating units being temporarily out of service for inspection, maintenance, refueling, modifications or other reasons. MidAmerican Energy's accredited capability currently exceeds the MISO's minimum requirements.

Transmission and Distribution

MidAmerican Energy's transmission and distribution systems included 3,800 miles of transmission lines, 37,000 miles of distribution lines and 380 substations as of December 31, 2015. Electricity from MidAmerican Energy's generating facilities and purchased electricity is delivered to wholesale markets and its retail customers via the transmission facilities of MidAmerican Energy and others. MidAmerican Energy participates in the MISO energy and ancillary services markets as a transmission-owning member and, accordingly, operates its transmission assets at the direction of the MISO. The MISO manages its energy and ancillary service markets using reliability-constrained economic dispatch of the region's generation. For both the day-ahead and real-time (every five minutes) markets, the MISO analyzes generation commitments to provide market liquidity and transparent pricing while maintaining transmission system reliability by minimizing congestion and maximizing efficient energy transmission. Additionally, through its FERC-approved open access transmission tariff ("OATT"), the MISO performs the role of transmission service provider throughout the MISO footprint and administers the long-term planning function. MISO and related costs of the participants are shared among the participants through a number of mechanisms in accordance with the MISO tariff.

Regulated Natural Gas Operations

MidAmerican Energy is engaged in the procurement, transportation, storage and distribution of natural gas for customers in its service territory. MidAmerican Energy purchases natural gas from various suppliers and contracts with interstate natural gas pipelines for transportation of the gas to MidAmerican Energy's service territory and for storage and balancing services. MidAmerican Energy sells natural gas and delivery services to end-use customers on its distribution system; sells natural gas to other utilities, municipalities and energy marketing companies; and transports natural gas through its distribution system for end-use customers who have independently secured their supply of natural gas. During 2015, 52% of the total natural gas delivered through MidAmerican Energy's distribution system was associated with transportation service.

Natural gas property consists primarily of natural gas mains and services lines, meters, and related distribution equipment, including feeder lines to communities served from natural gas pipelines owned by others. The natural gas distribution facilities of MidAmerican Energy included 23,000 miles of natural gas main and service lines as of December 31, 2015.

Customers

The percentages of natural gas sold to MidAmerican Energy's retail customers by jurisdiction for the years ended December 31 were as follows:

	2015	2014	2013
Iowa	76%	77%	76%
South Dakota	13	12	13
Illinois	10	10	10
Nebraska	1	1	1
	100%	100%	100%

The percentages of natural gas sold to MidAmerican Energy's retail and wholesale customers by class of customer, total Dth of natural gas sold, total Dth of transportation service and the average number of retail customers for the years ended December 31 were as follows:

	2015	2014	2013
Residential	42%	49%	46%
Commercial(1)	21	24	24
Industrial(1)	5	5	4
Total retail	68	78	74
Wholesale(2)	32	22	26
	100%	100%	100%
Total Dth of natural gas sold (in thousands)	110,105	115,209	115,857
Total Dth of transportation service (in thousands)	80,001	82,314	78,208
Total average number of retail customers (in thousands)	733	726	719

(1) Commercial and industrial customers are classified primarily based on the nature of their business and natural gas usage. Commercial customers are non-residential customers that use natural gas principally for heating. Industrial customers are non-residential customers that use natural gas principally for their manufacturing processes.

(2) Wholesale sales are generally made to other utilities, municipalities and energy marketing companies for eventual resale to end-use customers.

There are seasonal variations in MidAmerican Energy's regulated natural gas business that are principally due to the use of natural gas for heating. Typically, 50-60% of MidAmerican Energy's regulated natural gas revenue is reported in the months of January, February, March and December.

On January 6, 2014, MidAmerican Energy recorded its all-time highest peak-day delivery through its distribution system of 1,281,767 Dth. This peak-day delivery consisted of 69% traditional retail sales service and 31% transportation service. MidAmerican Energy's 2015/2016 winter heating season peak-day delivery as of February 5, 2016, was 1,093,449 Dth reached on January 17, 2016. This preliminary peak-day delivery included 72% traditional retail sales service and 28% transportation service.

Fuel Supply and Capacity

MidAmerican Energy uses several strategies designed to maintain a reliable natural gas supply and reduce the impact of volatility in natural gas prices on its regulated retail natural gas customers. These strategies include the purchase of a geographically diverse supply portfolio from producers and third party energy marketing companies, the use of leased storage and LNG peaking facilities, the use of financial derivatives to fix the price on a portion of the anticipated natural gas requirements of MidAmerican Energy's customers, and the maintenance of regulatory arrangements to share savings and costs with customers. Refer to "General Regulation" in Item 1 of this Form 10-K for a discussion of the purchased gas adjustment clauses ("PGA").

MidAmerican Energy contracts for firm natural gas pipeline capacity to transport natural gas from key production areas and liquid market centers to its service territory through direct interconnects to the pipeline systems of several interstate natural gas pipeline systems, including Northern Natural Gas, an affiliate company. MidAmerican Energy has multiple pipeline interconnections into several larger markets within its distribution system. Multiple pipeline interconnections create competition among pipeline suppliers for transportation capacity to serve those markets, thus reducing costs. In addition, multiple pipeline interconnections increase delivery reliability and give MidAmerican Energy the ability to optimize delivery of the lowest cost supply from the various production areas and liquid market centers into these markets. Benefits to MidAmerican Energy's distribution system customers are shared among all jurisdictions through a consolidated PGA.

At times, the natural gas pipeline capacity available through MidAmerican Energy's firm capacity portfolio may exceed the requirements of retail customers on MidAmerican Energy's distribution system. Firm capacity in excess of MidAmerican Energy's system needs can be resold to other companies to achieve optimum use of the available capacity. Past IUB and South Dakota Public Utilities Commission ("SDPUC") rulings have allowed MidAmerican Energy to retain 30% of the respective jurisdictional revenue on the resold capacity, with the remaining 70% being returned to customers through the PGAs.

MidAmerican Energy utilizes natural gas storage leased from the interstate pipelines to meet retail customer requirements, manage fluctuations in demand due to changes in weather and other usage factors and manage variation in seasonal natural gas pricing. MidAmerican Energy typically withdraws natural gas from storage during the heating season when customer demand is historically at its peak and injects natural gas into storage during off-peak months when customer demand is historically lower than during the heating season. MidAmerican Energy also utilizes its three LNG facilities to meet peak day demands during the winter heating season. The leased storage and LNG facilities reduce MidAmerican Energy's dependence on natural gas purchases during the volatile winter heating season and can deliver a significant portion of MidAmerican Energy's anticipated retail sales requirements on a peak winter day. For MidAmerican Energy's 2015/2016 winter heating season preliminary peak-day of January 17, 2016, supply sources used to meet deliveries to traditional retail sales service customers included 66% from leased storage, 30% from purchases from interstate pipelines and 4% from MidAmerican Energy's LNG facilities.

MidAmerican Energy attempts to optimize the value of its regulated transportation capacity, natural gas supply and leased storage arrangements by engaging in wholesale transactions. IUB and SDPUC rulings have allowed MidAmerican Energy to retain 50% of the respective jurisdictional margins earned on wholesale sales of natural gas, with the remaining 50% being returned to customers through the PGAs.

In 1995, the IUB gave initial approval of MidAmerican Energy's Incentive Gas Supply Procurement Plan, which seeks to establish a market-based reference price for key components of MidAmerican Energy's natural gas supply costs. In September 2013, the IUB extended the program through October 31, 2016. Under the program, as amended, MidAmerican Energy is required to file with the IUB annually a comparison of its actual natural gas procurement costs to the reference price. If MidAmerican Energy's actual natural gas supply costs for the applicable period were less or greater than an established tolerance band around the reference price, then MidAmerican Energy shares a portion of the savings or costs with customers. A similar program has also been in effect in South Dakota since 1995 and in October 2013 was extended through October 31, 2016. Since the implementation of these programs, MidAmerican Energy has successfully achieved savings relative to the applicable reference prices and shared such savings with its regulated retail natural gas customers. MidAmerican Energy's portion of shared savings is reflected in results of nonregulated energy operations.

MidAmerican Energy is not aware of any factors that would cause material difficulties in meeting its anticipated retail customer demand for the foreseeable future.

Demand-side Management

MidAmerican Energy has provided a comprehensive set of DSM programs to its Iowa electric and gas customers since 1990 and to customers in its other jurisdictions since 2008. The programs are designed to reduce energy consumption and more effectively manage when energy is used, including management of seasonal peak loads. Current programs offer services to customers such as energy engineering audits and information on how to improve the efficiency of their homes and businesses. To assist customers in investing in energy efficiency, MidAmerican Energy 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 residential customers who participate in the air conditioner load control program and nonresidential customers who participate in the nonresidential load management program. Although subject to prudence reviews, state regulations allow for contemporaneous recovery of costs incurred for the DSM programs through state-specific energy efficiency service charges paid by all retail electric and gas customers. During 2015, $111 million was expended on MidAmerican Energy's DSM programs resulting in estimated first-year energy savings of 303,000 MWh of electricity and 826,000 Dth of natural gas and an estimated peak load reduction of 288 MW of electricity and 9,710 Dth per day of natural gas.

Nonregulated Energy Operations

Nonregulated energy operations consist of competitive electricity and natural gas retail sales and gas income-sharing arrangements. Effective January 1, 2016, MidAmerican Energy, transferred its nonregulated competitive electricity and natural gas retail services operations to a subsidiary of BHE. Refer to Note 21 of the Notes to Financial Statements of MidAmerican Energy in Item 8 of this Form 10-K for a discussion of the transfer. Nonregulated electric operations predominantly include sales to retail customers in Illinois, Texas, Ohio, Maryland and other states that allow customers to choose their energy supplier. Nonregulated gas operations predominantly include sales to retail customers in Iowa and Illinois. For nonregulated retail services operations, electricity and natural gas are purchased from producers and third party energy marketing companies and sold directly to commercial, industrial and governmental end-users. Nonregulated retail services operations do not own electricity or natural gas production assets but hedge their contracted sales obligations either with physical supply arrangements or financial products. As of December 31, 2015, nonregulated retail services contracts in place for the sale of electricity totaled 18,865,000 MWh with a weighted average life of 2.1 years and for the sale of natural gas totaled 35,725,000 Dth with a weighted average life of 1.4 years. In addition, nonregulated retail services operations manage natural gas supplies for a number of smaller commercial end-users, which includes the sale of natural gas to these customers to meet their supply requirements. Refer to MidAmerican Energy's Item 7A in this Form 10-K for a discussion of commodity price risk and derivative contracts.

The percentages of electricity sold to MidAmerican Energy's nonregulated retail customers by state for the years ended December 31 were as follows:

	2015	**2014**	**2013**
Illinois	51%	58%	71%
Texas	15	17	16
Ohio	18	10	3
Maryland	7	8	6
Other	9	7	4
	100%	100%	100%

The percentages of natural gas sold to MidAmerican Energy's nonregulated customers by state for the years ended December 31 were as follows:

	2015	2014	2013
Iowa	87%	87%	89%
Illinois	8	8	7
Other	5	5	4
	100%	100%	100%

The financial results of nonregulated energy operations also include earnings from sharing arrangements under applicable state regulations and tariffs filed with the IUB and the SDPUC for MidAmerican Energy's regulated natural gas operations. Refer to the preceding "Regulated Natural Gas Operations" section in MidAmerican Energy's business discussion in Item 1 of this Form 10-K for further discussion of the sharing arrangements and the gas procurement program.

Employees

As of December 31, 2015, MidAmerican Funding and its subsidiaries had approximately 3,500 employees. As of December 31, 2015, MidAmerican Energy had approximately 3,500 employees, of which approximately 1,400 were covered by union contracts. MidAmerican Energy has three separate contracts with locals of the International Brotherhood of Electrical Workers ("IBEW") and the United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial and Service Workers International Union. A contract with the IBEW covering substantially all of the union employees expires April 30, 2017.

NV ENERGY (NEVADA POWER AND SIERRA PACIFIC)

General

NV Energy, an indirect wholly owned subsidiary of BHE acquired on December 19, 2013, is an energy holding company headquartered in Nevada whose principal subsidiaries are Nevada Power and Sierra Pacific. Nevada Power is a United States regulated electric utility company serving 0.9 million retail customers, including residential, commercial and industrial customers primarily in the Las Vegas, North Las Vegas, Henderson and adjoining areas. Sierra Pacific is a United States regulated electric and natural gas utility company serving 0.3 million retail electric customers, including residential, commercial and industrial customers, and 0.2 million retail and transportation natural gas customers in northern Nevada.

The Nevada Utilities are principally engaged in the business of generating, transmitting, distributing and selling electricity and, in the case of Sierra Pacific, in distributing, selling and transporting natural gas. Nevada Power and Sierra Pacific have electric service territories covering approximately 4,500 square miles and 41,400 square miles, respectively. Sierra Pacific has a natural gas service territory in an area of about 900 square miles in Reno and Sparks. Natural gas property consists primarily of natural gas mains and service lines, meters, and related distribution equipment, including feeder lines to communities served from natural gas pipelines owned by others. The natural gas distribution facilities of Sierra Pacific included 3,200 miles of natural gas mains and service lines as of December 31, 2015.

The Nevada Utilities also buy and sell 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. The Nevada Utilities are subject to comprehensive state and federal regulation. Regulated electric utility operation is Nevada Power's only segment while regulated electric utility operations and regulated natural gas operations are the two segments of Sierra Pacific. Principal industries served by the Nevada Utilities include gaming, recreation, warehousing, manufacturing and governmental. Sierra Pacific also serves the mining industry. In addition to the Nevada Utilities electric retail sales and Sierra Pacific's natural gas transportation, the Nevada Utilities sell electricity and natural gas to other utilities, municipalities and energy marketing companies on a wholesale basis.

Nevada Power's principal executive offices are located at 6226 West Sahara Avenue, Las Vegas, Nevada 89146, and its telephone number is (702) 402-5000. Nevada Power was incorporated in 1929 under the laws of the state of Nevada.

Sierra Pacific's principal executive offices are located at 6100 Neil Road, Reno, Nevada 89511, and its telephone number is (775) 834-4011. Sierra Pacific was incorporated in 1912 under the laws of the state of Nevada.

Regulated Operations

The Nevada Utilities deliver electricity and, in the case of Sierra Pacific, natural gas to customers in Nevada. The Nevada Utilities own facilities or have power purchase contracts for coal, natural gas, water, wind, solar, geothermal, biomass and waste heat resources to provide electricity. This electricity, together with electricity purchased on the wholesale market, is then transmitted via a grid of transmission lines, which are part of the Western Interconnection, the regional grid in the United States. The Western Interconnection includes the interconnected transmission systems of 14 western states, two Canadian provinces and parts of Mexico. The electricity is then transformed to lower voltages and delivered to customers through the Nevada Utilities' distribution system.

The Nevada Utilities seek to manage growth in their customer demand through the construction and purchase of cost-effective, environmentally prudent and efficient sources of electricity supply and through energy efficiency programs. NV Energy began participating in the EIM in December 2015. By joining PacifiCorp in the EIM, the Nevada Utilities and the California ISO extended the scope of the existing 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 through improved situational awareness and responsiveness.

The Nevada Utilities' primary goal is to provide safe, reliable electricity to their customers at a reasonable cost. The Nevada Utilities operate under certificates of public convenience and necessity as regulated by the PUCN, and as such the Nevada Utilities have an obligation to provide electricity service to those customers within their service territory. In return, the PUCN has established rates on a cost-of-service basis, which are designed to allow the Nevada Utilities an opportunity to recover all prudently incurred costs of providing services and an opportunity to earn a reasonable return on their investment.

The Nevada Utilities' electric and natural gas operations are conducted under numerous nonexclusive franchise agreements, revocable permits and licenses obtained from federal, state and local authorities. The expiration of these franchise agreements range from 2020 through 2032 for Nevada Power and 2016 through 2035 for Sierra Pacific.

The percentages of Sierra Pacific's operating revenue and operating income derived from the following business activities for the years ended December 31 were as follows:

	2015	2014	2013
Operating revenue:			
Electric	86%	86%	88%
Gas	14	14	12
	100%	100%	100%
Operating income:			
Electric	91%	93%	96%
Gas	9	7	4
	100%	100%	100%

Regulated Electric Operations

Customers

Electricity sold to the Nevada Utilities' retail and wholesale customers by class of customer and the average number of retail customers for the years ended December 31 were as follows:

	2015		2014		2013	
Nevada Power:						
GWh sold:						
Residential	9,246	42%	8,923	42%	9,012	42%
Commercial	4,635	21	4,489	21	4,426	21
Industrial	7,571	34	7,486	36	7,533	36
Other	214	1	211	1	212	1
Total retail	21,666	98	21,109	100	21,183	100
Wholesale	353	2	20	—	36	—
Total GWh sold	22,019	100%	21,129	100%	21,219	100%
Average number of retail customers (in thousands):						
Residential	782	88%	770	88%	754	88%
Commercial	104	12	102	12	103	12
Industrial	2	—	2	—	2	—
Total	888	100%	874	100%	859	100%
Sierra Pacific:						
GWh sold:						
Residential	2,315	26%	2,268	26%	2,370	26%
Commercial	2,942	33	2,944	34	2,948	33
Industrial	2,973	34	2,869	33	2,818	31
Other	16	—	16	—	16	—
Total retail	8,246	93	8,097	93	8,152	90
Wholesale	664	7	645	7	875	10
Total GWh sold	8,910	100%	8,742	100%	9,027	100%
Average number of retail customers (in thousands):						
Residential	288	86%	285	86%	281	86%
Commercial	46	14	46	14	46	14
Total	334	100%	331	100%	327	100%

Customer Usage and Seasonality

In addition to the variations in weather from year to year, fluctuations in economic conditions within the Nevada Utilities' service territory and elsewhere can impact customer usage, particularly for gaming, mining and wholesale customers. Wholesale sales are impacted by market prices for energy relative to the incremental cost to generate power.

There are seasonal variations in the Nevada Utilities' electric business that are principally related to weather and the related use of electricity for air conditioning. Typically, 46-50% of Nevada Power's and 35-38% of Sierra Pacific's regulated electric revenue is reported in the months of June, July, August and September.

The annual hourly peak customer demand on the Nevada Utilities' electric systems occurs as a result of air conditioning use during the cooling season. Peak demand represents the highest demand on a given day and at a given hour. On June 30, 2015, customer usage of electricity caused an hourly peak demand of 5,864 MW on Nevada Power's electric distribution system, which is 2 MW less than the record hourly peak demand of 5,866 MW set July 5, 2007. On June 30, 2015, customer usage of electricity caused an hourly peak demand of 1,711 MW on Sierra Pacific's electric distribution system, which is 50 MW less than the record hourly peak demand of 1,761 MW set July 14, 2014.

Generating Facilities and Fuel Supply

The Nevada Utilities have ownership interest in a diverse portfolio of generating facilities. The following table presents certain information regarding the Nevada Utilities' owned generating facilities as of December 31, 2015:

Generating Facility	Location	Energy Source	Installed	Facility Net Capacity (MW)(1)	Net Owned Capacity (MW)(1)
Nevada Power:					
NATURAL GAS:					
Clark	Las Vegas, NV	Natural gas	1973-2008	1,102	1,102
Lenzie	Las Vegas, NV	Natural gas	2006	1,102	1,102
Harry Allen	Las Vegas, NV	Natural gas	1995-2011	628	628
Higgins	Primm, NV	Natural gas	2004	530	530
Silverhawk	Las Vegas, NV	Natural gas	2004	520	390
Las Vegas	Las Vegas, NV	Natural gas	1994-2003	272	272
Sun Peak	Las Vegas, NV	Natural gas/oil	1991	210	210
				4,364	4,234
COAL:					
Reid Gardner Unit No. 4(2)	Moapa, NV	Coal	1983	257	257
Navajo Unit Nos. 1, 2 and 3(2)	Page, AZ	Coal	1974-1976	2,250	255
				2,507	512
RENEWABLES:					
Goodsprings	Goodsprings, NV	Waste heat	2010	5	5
Nellis(3)	Las Vegas, NV	Solar	2015	15	15
				20	20
Total Nevada Power				6,891	4,766
Sierra Pacific:					
NATURAL GAS:					
Tracy	Sparks, NV	Natural gas	1974-2008	753	753
Ft. Churchill	Yerington, NV	Natural gas	1968-1971	226	226
Clark Mountain	Sparks, NV	Natural gas	1994	132	132
				1,111	1,111
COAL:					
Valmy Unit Nos. 1 and 2	Valmy, NV	Coal	1981-1985	522	261
Total Sierra Pacific				1,633	1,372
Total NV Energy				8,524	6,138

(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 (in MW) under specified conditions. Net Owned Capacity indicates Nevada Power or Sierra Pacific's ownership of Facility Net Capacity.

(2) Nevada Power currently anticipates retiring Reid Gardner Unit No. 4 in December 2017 and eliminating its interest in Navajo Unit Nos. 1, 2 and 3 in 2019. Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for further discussion.

(3) The Nellis Generating Facility was placed into service in November 2015.

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

	2015	2014	2013
Nevada Power:			
Natural gas	65%	56%	65%
Coal	7	20	13
Total energy generated	72	76	78
Energy purchased - short-term contracts and other	1	1	3
Energy purchased - long-term contracts (renewable)[1]	12	10	10
Energy purchased - long-term contracts (non-renewable)	15	13	9
	100%	100%	100%
Sierra Pacific:			
Natural gas	41%	46%	40%
Coal	13	21	15
Total energy generated	54	67	55
Energy purchased - short-term contracts and other	1	1	4
Energy purchased - long-term contracts (renewable)[1]	9	10	10
Energy purchased - long-term contracts (non-renewable)	36	22	31
	100%	100%	100%

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

The Nevada Utilities are required to have resources available to continuously meet their customer needs. The percentage of the Nevada Utilities' 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. The Nevada Utilities evaluate these factors continuously in order to facilitate economical dispatch of their generating facilities. When factors for one energy source are less favorable, the Nevada Utilities must place more reliance on other energy sources. As long as the Nevada Utilities purchases are deemed prudent by the PUCN, through their annual prudency review, the Nevada Utilities are permitted to recover the cost of fuel and purchased power. The Nevada Utilities also have the ability to reset quarterly BTER, with PUCN approval, based on the last twelve months fuel costs and purchased power and to reset quarterly DEAA.

In response to these energy supply challenges, the Nevada Utilities have adopted an approach to managing the energy supply function that has three primary elements. The first element is a set of management guidelines to procuring and optimizing the supply portfolio that is consistent with the requirements of a load serving entity with a full requirements obligation, and with the growth of distributed generation serving a small but growing group of customers with partial requirements. The second element is an energy risk management and risk control approach that ensures clear separation of roles between the day-to-day management of risks and compliance monitoring and control and ensures clear distinction between policy setting (or planning) and execution. Lastly, the Nevada Utilities pursue a process of ongoing regulatory involvement and acknowledgment of the resource portfolio management plans.

The Nevada Utilities have entered into multiple long-term power purchase contracts (three or more years) with suppliers that generate electricity utilizing coal, natural gas and renewable resources. Nevada Power has entered into contracts with a total capacity of 2,253 MW with contract termination dates ranging from 2017 to 2040. Included in these contracts are 1,257 MW of capacity of renewable energy, of which 228 MW of capacity are under development or construction and not currently available. Sierra Pacific has entered into contracts with a total capacity of 508 MW with contract termination dates ranging from 2016 to 2039. Included in these contracts are 311 MW of capacity of renewable energy, of which 101 MW of capacity are under development or construction and not currently available.

The Nevada Utilities manage certain risks relating to their supply of electricity and fuel requirements by entering into various contracts, which may be accounted for as derivatives, including forwards, futures, options, swaps and other agreements. Refer to NV Energy's "General Regulation" section in Item 1 of this Form 10-K for a discussion of energy cost recovery by jurisdiction and Nevada Power's Item 7A and Sierra Pacific's Item 7A in this Form 10-K for a discussion of commodity price risk and derivative contracts.

Natural Gas

The Nevada Utilities rely on first-of-the-month indexed physical gas purchases for the majority of natural gas needed to operate its generating facilities. To secure natural gas supplies for the generating facilities, the Nevada Utilities execute purchases pursuant to a PUCN approved four season laddering strategy. In 2015, natural gas supply net purchases averaged 361,573 and 125,361 Dth per day with the winter period contracts averaging 307,504 and 142,009 Dth per day and the summer period contracts averaging 399,724 and 113,615 Dth per day for Nevada Power and Sierra Pacific, respectively. The Nevada Utilities believe supplies from these sources are presently adequate and available to meet its needs.

The Nevada Utilities contract for firm natural gas pipeline capacity to transport natural gas from production areas to their service territory through direct interconnects to the pipeline systems of several interstate natural gas pipeline systems, including Nevada Power contracts with Kern River, an affiliated company. Sierra Pacific utilizes natural gas storage leased from interstate pipelines to meet retail customer requirements and to manage the daily changes in demand due to changes in weather and other usage factors. The stored natural gas is typically replaced during off-peak months when the demand for natural gas is historically lower than during the heating season.

Coal

The Nevada Utilities have no coal commitments for 2016 or beyond and will rely on spot market solicitations for any coal supplies needed during 2016 and regularly monitor the western coal market for opportunities to meet these needs. Nevada Power's coal supply plan has the overall goal of eliminating its coal pile by Reid Gardner Unit No. 4's expected retirement date of December 2017. The Nevada Utilities have transportation services contracts with Union Pacific Railroad Company to ship coal from various origins in Central Utah, Western Colorado and Wyoming that expire December 31, 2017 for Nevada Power and December 31, 2019 for Sierra Pacific. The transportation services contracts with Union Pacific Railroad Company contain no firm volume or financial commitments. The Navajo Generating Station, jointly owned by Nevada Power along with five other entities and operated by Salt River Project, has a coal purchase agreement that extends through December 2019.

Transmission and Distribution

The Nevada Utilities' transmission system is part of the Western Interconnection. The Nevada Utilities' transmission system, together with contractual rights on other transmission systems, enables the Nevada Utilities to integrate and access generation resources to meet their customer load requirements. Nevada Power's transmission and distribution systems included approximately 2,000 miles of transmission lines, 24,000 miles of distribution lines and 200 substations as of December 31, 2015. Sierra Pacific's transmission and distribution systems included approximately 2,300 miles of transmission lines, 16,500 miles of distribution lines and 200 substations as of December 31, 2015.

ON Line is a 231 mile, 500-kV transmission line connecting Nevada Power's and Sierra Pacific's service territories. ON Line provides the ability to jointly dispatch energy throughout Nevada and provide access to renewable energy resources in parts of northern and eastern Nevada, which enhances the Nevada Utilities' ability to manage and optimize their generating facilities. ON Line provides between 600 and 800 MW of transfer capability with interconnection between the Robinson Summit substation on the Sierra Pacific system and the Harry Allen substation on the Nevada Power system. ON Line was a joint project between the Nevada Utilities and Great Basin Transmission, LLC. The Nevada Utilities own a 25% interest in ON Line and have entered into a long-term transmission use agreement with Great Basin Transmission, LLC for its 75% interest in ON Line for a term of 41 years. The Nevada Utilities share of its 25% interest in ON Line and the long-term transmission use agreement is split 95% for Nevada Power and 5% for Sierra Pacific.

The Nevada Utilities began participating in the EIM operated by the California ISO in December 2015. The EIM expands the real-time component of the California ISO to optimize and balance electricity supply and demand every five minutes across the EIM 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 EIM footprint every five minutes. In addition to generation resource bids, the California ISO market operator also receives continuous real-time updates of the 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 PUCN's final order approving the merger between BHE and NV Energy stipulated that the Nevada Utilities would obtain PUCN authorization prior to participating in an EIM. The PUCN issued an order in August 2014 finding that it is in the public interest to grant the application and that NV Energy met the merger stipulation requirement to obtain PUCN approval prior to participating in an EIM.

Future Generation

The Nevada Utilities file IRPs every three years, and as necessary, may file amendments to their IRPs. IRPs are prepared in compliance with Nevada laws and regulations and cover a 20-year period. IRPs develop a comprehensive, integrated plan that considers customer energy requirements and propose the resources to meet those requirements in a manner that is consistent with prevailing market fundamentals. The ultimate goal of the IRPs is to balance the objectives of minimizing costs and reducing volatility while reliably meeting the electric needs of Nevada Power's and Sierra Pacific's customers. Projects approved through the IRP process still remain subject to review by the PUCN.

In July 2015, Nevada Power filed its triennial IRP and in December 2015, Nevada Power received PUCN approval. Sierra Pacific is scheduled to file a triennial IRP before July 1, 2016.

The energy supply function at the Nevada Utilities is responsible for the operation of the Nevada Utilities' owned generation, the procurement of all fuels and purchased power and optimization of resources (e.g., physical and economic dispatch).

There is the potential for continued price volatility in the Nevada Utilities' service territories, particularly during peak periods. Too great of a dependence on generation from the wholesale market can lead to power price volatilities depending on available power supply and prevailing natural gas prices. The Nevada Utilities face load obligation uncertainty due to the potential for customer switching. Some counterparties in these areas have significant credit difficulties, representing credit risk to the Nevada Utilities. Finally, the Nevada Utilities' own credit situation can have an impact on its ability to enter into transactions.

Within the energy supply planning process, there are three key components covering different time frames:

- The PUCN-approved long-term IRP which is filed every three years and has a 20-year planning horizon;
- The PUCN-approved energy supply plan which is an intermediate term resource procurement and risk management plan that establishes the supply portfolio strategies within which intermediate term resource requirements will be met and has a one to three year planning horizon; and
- Tactical execution activities with a one-month to twelve-month focus.

The energy supply plan operates in conjunction with the PUCN-approved 20-year IRP. It serves as a guide for near-term execution and fulfillment of energy needs. When the energy supply plan calls for executing contracts of longer than three years, PUCN approval is required.

Energy-Efficiency Programs

The Nevada Utilities have provided a comprehensive set of energy efficiency, demand response and conservation programs to their Nevada electric customers. The programs are designed to reduce energy consumption and more effectively manage when energy is used, including management of seasonal peak loads. Current programs offer services to customers such as energy audits and customer education and awareness efforts that provide information on how to improve the efficiency of their homes and businesses. To assist customers in investing in energy efficiency, the Nevada Utilities have offered 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 residential customers who participate in the air conditioner load control program and nonresidential customers who participate in the nonresidential load management program. Energy efficiency program costs are recovered through annual rates set by the PUCN, and adjusted based on the Nevada Utilities' annual filing to recover current program costs and any over or under collections from the prior filing, subject to prudence review. During 2015, Nevada Power spent $37 million on energy efficiency programs, resulting in an estimated 187,226 MWh of electric energy savings and an estimated 32 MW of electric peak load management. During 2015, Sierra Pacific spent $10 million on energy efficiency programs, resulting in an estimated 50,643 MWh of electric energy savings and an estimated 6 MW of electric peak load management.

Regulated Natural Gas Operations

Sierra Pacific is engaged in the procurement, transportation and distribution of natural gas for customers in its service territory. Sierra Pacific purchases natural gas from various suppliers and contracts with interstate natural gas pipelines for transportation of the natural gas from the production areas to Sierra Pacific's service territory and for storage services to manage fluctuations in system demand and seasonal pricing. Sierra Pacific sells natural gas and delivery services to end-use customers on its distribution system; sells natural gas to other utilities, municipalities and energy marketing companies; and transports natural gas through its distribution system for a number of end-use customers who have independently secured their supply of natural gas. During 2015, 11% of the total natural gas delivered through Sierra Pacific's distribution system was for transportation service.

Customers

The percentages of natural gas sold to Sierra Pacific's retail and wholesale customers by class of customer, total Dth of natural gas sold, total Dth of transportation service and the average number of retail customers for the years ended December 31 were as follows:

	2015	2014	2013
Residential	49%	51%	49%
Commercial(1)	24	25	23
Industrial(1)	8	9	8
Total retail	81	85	80
Wholesale	19	15	20
	100%	100%	100%
Total Dth of natural gas sold (in thousands)	17,600	15,519	19,957
Total Dth of transportation service (in thousands)	2,288	2,275	2,281
Total average number of retail customers (in thousands)	159	156	155

(1) Commercial and industrial customers are classified primarily based on their natural gas usage. Commercial customers are non-residential customers with monthly gas usage less than 12,000 therms during five consecutive winter months. Industrial customers are non-residential customers that use natural gas in excess of 12,000 therms during one or more winter months.

There are seasonal variations in Sierra Pacific's regulated natural gas business that are principally due to the use of natural gas for heating. Typically, 48-59% of Sierra Pacific's regulated natural gas revenue is reported in the months of January, February, March and December.

On December 31, 2015, Sierra Pacific recorded its highest peak-day natural gas delivery of 143,903 Dth, which is 19,671 Dth less than the record peak-day delivery of 163,574 Dth set on December 9, 2013. This peak-day delivery consisted of 93% traditional retail sales service and 7% transportation service.

Fuel Supply and Capacity

The purchase of natural gas for Sierra Pacific's regulated natural gas operations is done in combination with the purchase of natural gas for Sierra Pacific's regulated electric operations. In response to energy supply challenges, Sierra Pacific has adopted an approach to managing the energy supply function that has three primary elements, as discussed earlier under Generating Facilities and Fuel Supply. Similar to Sierra Pacific's regulated electric operations, as long as Sierra Pacific's purchases of natural gas are deemed prudent by the PUCN, through its annual prudency review, Sierra Pacific is permitted to recover the cost of natural gas. Sierra Pacific also has the ability to reset quarterly BTER, with PUCN approval, based on the last twelve months fuel costs and to reset quarterly DEAA.

Employees

As of December 31, 2015, Nevada Power had approximately 1,400 employees, of which approximately 700 were covered by a collective bargaining agreement with the International Brotherhood of Electrical Workers.

As of December 31, 2015, Sierra Pacific had approximately 1,000 employees, of which approximately 600 were covered by a collective bargaining agreement with the International Brotherhood of Electrical Workers.

NORTHERN POWERGRID

Northern Powergrid, an indirect wholly owned subsidiary of BHE, is a holding company which owns two companies that distribute electricity in Great Britain, Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc. In addition to the Northern Powergrid Distribution Companies, Northern Powergrid also owns a meter asset rental business that leases smart meters to energy suppliers in the United Kingdom and Ireland, an engineering contracting business that provides electrical infrastructure contracting services primarily to third parties and a hydrocarbon exploration and development business that is focused on developing integrated upstream gas projects in Europe and Australia.

The Northern Powergrid Distribution Companies serve 3.9 million end-users and operate in the north-east of England from North Northumberland through Tyne and Wear, County Durham and Yorkshire to North Lincolnshire, an area covering 10,000 square miles. The principal function of the Northern Powergrid Distribution Companies is to build, maintain and operate the electricity distribution network through which the end-user receives a supply of electricity.

The Northern Powergrid Distribution Companies receive electricity from the national grid transmission system and from generators that are directly connected to the distribution network and distribute it to end-users' premises using their networks of transformers, switchgear and distribution lines and cables. Substantially all of the end-users in the Northern Powergrid Distribution Companies' distribution service areas are directly or indirectly connected to the Northern Powergrid Distribution Companies' networks and electricity can only be delivered to these end-users through their distribution systems, thus providing the Northern Powergrid Distribution Companies with distribution volumes that are relatively stable from year to year. The Northern Powergrid Distribution Companies charge fees for the use of their distribution systems to the suppliers of electricity.

The suppliers purchase electricity from generators, sell the electricity to end-user customers and use the Northern Powergrid Distribution Companies' distribution networks pursuant to an industry standard "Distribution Connection and Use of System Agreement." One supplier, RWE Npower PLC and certain of its affiliates, represented 24% of the total combined distribution revenue of the Northern Powergrid Distribution Companies during 2015. Variations in demand from end-users can affect the revenues that are received by the Northern Powergrid Distribution Companies in any year, but such variations have no effect on the total revenue that the Northern Powergrid Distribution Companies are allowed to recover in a price control period. Under- or over-recoveries against price-controlled revenues are carried forward into prices for future years.

The Northern Powergrid Distribution Companies' combined service territory features a diverse economy with no dominant sector. The mix of rural, agricultural, urban and industrial areas covers a broad customer base ranging from domestic usage through farming and retail to major industry including automotives, chemicals, mining, steelmaking and offshore marine construction. The industry within the area is concentrated around the principal centers of Newcastle, Middlesbrough, Sheffield and Leeds.

The price controlled revenue of the regulated distribution companies is set out in the special conditions of the licenses of those companies. The licenses are enforced by the regulator, the Gas and Electricity Markets Authority through its office of gas and electric markets (known as "Ofgem") and limit increases to allowed revenues (or may require decreases) based upon the rate of inflation, other specified factors and other regulatory action. Changes to the price controls can be made by the regulator, but if a licensee disagrees with a change to its license it can appeal the matter to the United Kingdom's Competition and Markets Authority. It has been the convention in Great Britain for regulators to conduct periodic regulatory reviews before making proposals for any changes to the price controls. The current electricity distribution price control became effective April 1, 2015 and is expected to continue through March 31, 2023. Following initial submission of the Northern Powergrid Distribution Companies' business plans for the current price control period to Ofgem in July 2013 and resubmission, following feedback from Ofgem in March 2014, the final determinations for the current price control were published in November 2014. In March 2015 Northern Powergrid was the only electricity distributor to appeal Ofgem's price control decision and in September 2015 the appeal authority allowed part of the appeal, awarding an additional £30 million (in 2012/13 prices) in expenditure allowances.

GWh and percentages of electricity distributed to the Northern Powergrid Distribution Companies' end-users and the total number of end-users as of and for the years ended December 31 were as follows:

	2015		2014		2013	
Northern Powergrid (Northeast) Limited:						
Residential	5,144	34%	5,161	34%	5,379	35%
Commercial	2,417	16%	2,393	16	2,485	16
Industrial	7,160	48%	7,181	48	7,166	47
Other	231	2%	262	2	269	2
	14,952	100%	14,997	100%	15,299	100%
Northern Powergrid (Yorkshire) plc:						
Residential	7,574	35%	7,481	35%	7,812	35%
Commercial	3,352	16	3,347	16	3,501	16
Industrial	10,403	48	10,486	48	10,793	48
Other	299	1	322	1	313	1
	21,628	100%	21,636	100%	22,419	100%
Total electricity distributed	36,580		36,633		37,718	
Number of end-users (in thousands):						
Northern Powergrid (Northeast) Limited	1,597		1,593		1,588	
Northern Powergrid (Yorkshire) plc	2,294		2,286		2,279	
	3,891		3,879		3,867	

As of December 31, 2015, the Northern Powergrid Distribution Companies' combined electricity distribution network included 18,000 miles of overhead lines, 40,000 miles of underground cables and 725 major substations.

BHE PIPELINE GROUP

The BHE Pipeline Group consists of BHE's interstate natural gas pipeline companies, Northern Natural Gas and Kern River.

Northern Natural Gas

Northern Natural Gas, an indirect wholly owned subsidiary of BHE, owns the largest interstate natural gas pipeline system in the United States, as measured by pipeline miles, which reaches from southern Texas to Michigan's Upper Peninsula. Northern Natural Gas primarily transports and stores natural gas for utilities, municipalities, gas marketing companies, industrial and commercial users and other end-users. Northern Natural Gas' pipeline system consists of two operationally integrated systems. Its traditional end-use and distribution market area in the northern part of its system, referred to as the Market Area, includes points in Iowa, Nebraska, Minnesota, Wisconsin, South Dakota, Michigan and Illinois. Its natural gas supply and delivery service area in the southern part of its system, referred to as the Field Area, includes points in Kansas, Texas, Oklahoma and New Mexico. Northern Natural Gas' pipeline system consists of 14,700 miles of natural gas pipelines, including 6,300 miles of mainline transmission pipelines and 8,400 miles of branch and lateral pipelines, with a Market Area design capacity of 5.7 Bcf per day, a Field Area delivery capacity of 1.7 Bcf per day to the Market Area and over 73 Bcf of firm service and operational storage cycle capacity in five storage facilities. Northern Natural Gas' pipeline system is configured with approximately 2,300 active receipt and delivery points which are integrated with the facilities of LDCs. Many of Northern Natural Gas' LDC customers are part of combined utilities that also use natural gas as a fuel source for electric generation. Northern Natural Gas delivers over 0.9 Tcf of natural gas to its customers annually.

Northern Natural Gas' transportation rates and most of its storage rates are cost-based. These rates are designed to provide Northern Natural Gas with an opportunity to recover its costs of providing services and earn a reasonable return on its investments. In addition, Northern Natural Gas has fixed rates that were market-based for certain of its firm storage contracts with contract terms that expire in 2028.

Northern Natural Gas' operating revenue for the years ended December 31 was as follows (in millions):

	2015		2014		2013	
Transportation:						
Market Area	$ 474	72%	$ 457	63%	$ 444	75%
Field Area	84	13	100	14	64	11
Total transportation	558	85	557	77	508	86
Storage	62	9	61	8	58	10
Total transportation and storage revenue	620	94	618	85	566	96
Gas, liquids and other sales	36	6	106	15	27	4
Total operating revenue	$ 656	100%	$ 724	100%	$ 593	100%

Substantially all of Northern Natural Gas' Market Area transportation revenue is generated from reservation charges, with the balance from usage charges. Northern Natural Gas transports natural gas primarily to local distribution markets and end-users in the Market Area. Northern Natural Gas provides service to 81 utilities, including MidAmerican Energy, an affiliate company, which serve numerous residential, commercial and industrial customers. Most of Northern Natural Gas' transportation capacity in the Market Area is committed to customers under firm transportation contracts, where customers pay Northern Natural Gas a monthly reservation charge for the right to transport natural gas through Northern Natural Gas' system. Reservation charges are required to be paid regardless of volumes transported or stored. As of December 31, 2015, over 51% of Northern Natural Gas' customers' entitlement in the Market Area have terms beyond 2018. As of December 31, 2015, the weighted average remaining contract term for Northern Natural Gas' Market Area firm transportation contracts is approximately four years.

Northern Natural Gas' Field Area customers consist primarily of energy marketing companies and midstream companies, which take advantage of the price spread opportunities created between Field Area supply points and the Field-Market Demarcation Point. In addition, there are a growing number of midstream customers that are delivering gas south to the Field Area Waha Hub market. The remaining Field Area transportation service is sold to power generators connected to Northern Natural Gas' system in Texas and New Mexico that are contracted on a long-term basis with terms that extend to at least 2019, and various LDCs, energy marketing companies and midstream companies for both connected and off-system markets.

Northern Natural Gas' storage services are provided through the operation of one underground natural gas storage field in Iowa, two underground natural gas storage facilities in Kansas and two LNG storage peaking units, one in Iowa and one in Minnesota. The three underground natural gas storage facilities and two LNG storage peaking units have a total firm service and operational storage cycle capacity of over 73 Bcf and over 2.0 Bcf per day of peak delivery capability. These storage facilities provide operational flexibility for the daily balancing of Northern Natural Gas' system and provide services to customers for their winter peaking and year-round load swing requirements.

Northern Natural Gas has 59.3 Bcf of firm storage contracts with its cost-based and market-based services. Firm storage contracts with cost-based rates, representing 51.3 Bcf, have an average remaining contract term of six years and are contracted at maximum tariff rates. The remaining firm storage contracts with market-based rates, representing 8.0 Bcf, have an average remaining contract term of twelve years.

Except for quantities of natural gas owned and managed for operational and system balancing purposes, Northern Natural Gas does not own the natural gas that is transported through its system. The sale of natural gas for operational and system balancing purposes accounts for the majority of the remaining operating revenue.

During 2015, Northern Natural Gas had three customers, including MidAmerican Energy, that each accounted for greater than 10% of its transportation and storage revenue and its ten largest customers accounted for 65% of its system-wide transportation and storage revenue. Northern Natural Gas has agreements with terms from 2017 to 2019 to retain its three largest customers' volumes. The loss of any of these significant customers, if not replaced, could have a material adverse effect on Northern Natural Gas.

Northern Natural Gas' extensive pipeline system, which is interconnected with many interstate and intrastate pipelines in the national grid system, has access to multiple major supply basins. Direct access is available from producers in the Anadarko, Permian and Hugoton basins, some of which have recently experienced increased production from shale and tight sands formations adjacent to Northern Natural Gas' pipeline. Since 2011, the pipeline has connected 1,595,000 Dth per day of supply access from the Wolfberry shale formation in west Texas and from the Granite Wash tight sands formations in the Texas panhandle and in Oklahoma. Additionally, Northern Natural Gas has interconnections with several interstate pipelines and several intrastate pipelines with receipt, delivery, or bi-directional capabilities. Because of Northern Natural Gas' location and multiple interconnections it is able to access natural gas from other key production areas, such as the Rocky Mountain and western Canadian basins. The Rocky Mountain basins are accessed through interconnects with Trailblazer Pipeline Company, Tallgrass Interstate Gas Transmission, LLC, Cheyenne Plains Gas Pipeline Company, LLC, Colorado Interstate Gas Company and Rockies Express Pipeline, LLC ("REX"). The western Canadian basins are accessed through interconnects with Northern Border Pipeline Company ("Northern Border"), Great Lakes Gas Transmission Limited Partnership ("Great Lakes") and Viking Gas Transmission Company ("Viking"). This supply diversity and access to both stable and growing production areas provides significant flexibility to Northern Natural Gas' system and customers.

Northern Natural Gas' system experiences significant seasonal swings in demand and revenue, with the highest demand and revenues typically occurring during the months of November through March. This seasonality provides Northern Natural Gas with opportunities to deliver additional value-added services, such as firm and interruptible storage services. As a result of Northern Natural Gas' geographic location in the middle of the United States and its many interconnections with other pipelines, Northern Natural Gas has the opportunity to augment its steady end user and LDC revenue by capitalizing on opportunities for shippers to reach additional markets, such as Chicago, Illinois, other parts of the Midwest, and Texas, through interconnects.

Kern River

Kern River, an indirect wholly owned subsidiary of BHE, owns an interstate natural gas pipeline system that extends from supply areas in the Rocky Mountains to consuming markets in Utah, Nevada and California. Kern River provided 22% of California's demand for natural gas in 2014. Kern River's pipeline system consists of 1,700 miles of natural gas pipelines, including 1,400 miles of mainline section and 300 miles of common facilities, with a design capacity of 2,166,575 Dth per day. Kern River owns the entire mainline section, which extends from the system's point of origination near Opal, Wyoming, through the Central Rocky Mountains area into Daggett, California. The mainline section consists of 1,300 miles of 36-inch diameter pipeline and 100 miles of various laterals that connect to the mainline. The common facilities are jointly owned by Kern River and Mojave Pipeline Company ("Mojave") as tenants-in-common, and ownership may increase or decrease pursuant to the capital contributions made by each respective joint owner. Kern River has exclusive rights to 1,613,400 Dth per day of the common facilities' capacity, and Mojave has exclusive rights to 414,000 Dth per day of capacity. Except for quantities of natural gas owned for operational purposes, Kern River does not own the natural gas that is transported through its system. Kern River's transportation rates are cost-based. The rates are designed to provide Kern River with an opportunity to recover its costs of providing services and earn a reasonable return on its investments.

95% of Kern River's design capacity of 2,166,575 Dth per day is contracted pursuant to long-term firm natural gas transportation service agreements, whereby Kern River receives natural gas on behalf of customers at designated receipt points and transports the natural gas on a firm basis to designated delivery points. In return for this service, each customer pays Kern River a fixed monthly reservation fee based on each customer's maximum daily quantity, which represents 94% of total operating revenue, and a commodity charge based on the actual amount of natural gas transported pursuant to its long-term firm natural gas transportation service agreements and Kern River's tariff.

These long-term firm natural gas transportation service agreements expire between March 2017 and April 2033 and have a weighted-average remaining contract term of over eight years. Kern River's customers include electric utilities and natural gas distribution utilities, major oil and natural gas companies or affiliates of such companies, electricity generating companies, energy marketing and trading companies, and financial institutions. The utilities provide services in Utah, Nevada and California. As of December 31, 2015, nearly 80% of the firm capacity under contract has primary delivery points in California, with the flexibility to access secondary delivery points in Nevada and Utah.

During 2015, Kern River had one customer, Nevada Power Company, an affiliate company, who accounted for greater than 10% of its revenue. The loss of this significant customer, if not replaced, could have a material adverse effect on Kern River.

Competition

The Pipeline Companies compete with other pipelines on the basis of cost, flexibility, reliability of service and overall customer service, with the end-user's decision being made primarily on the basis of delivered price, which includes both the natural gas commodity cost and its transportation cost. Natural gas also competes with alternative energy sources, including coal, nuclear energy, wind, geothermal, solar and fuel oil. Legislation and governmental regulations, the weather, the futures market, production costs and other factors beyond the control of the Pipeline Companies influence the price of the natural gas commodity.

The natural gas industry is undergoing a significant shift in supply sources. Production from conventional sources continues to decline while production from unconventional sources, such as shale gas, is increasing. This shift will affect the supply patterns, the flows, the locational and seasonal natural gas price spreads and rates that can be charged on pipeline systems. The impact will vary among pipelines according to the location and the number of competitors attached to these new supply sources.

Electric power generation has been the source of most of the growth in demand for natural gas over the last 10 years, and this trend is expected to continue in the future. The growth of natural gas in this sector is influenced by regulation, new sources of natural gas, competition with other energy sources, primarily coal, and increased consumption of electricity as a result of economic growth. Short-term market shifts have been driven by relative costs of coal-fueled generation versus natural gas-fueled generation. A long-term market shift away from the use of coal in power generation could be driven by environmental regulations. The future demand for natural gas could be increased by regulations limiting or discouraging coal use. However, natural gas demand could potentially be adversely affected by laws mandating or encouraging renewable power sources that produce fewer GHG emissions than natural gas.

The Pipeline Companies' ability to extend existing customer contracts, remarket expiring contracted capacity or market new capacity is dependent on competitive alternatives, the regulatory environment and the market supply and demand factors at the relevant dates these contracts are eligible to be renewed or extended. The duration of new or renegotiated contracts will be affected by current commodity and transportation prices, competitive conditions and customers' judgments concerning future market trends and volatility.

Subject to regulatory requirements, the Pipeline Companies attempt to recontract or remarket capacity at the maximum rates allowed under their tariffs, although at times the Pipeline Companies discount these rates to remain competitive. The Pipeline Companies' existing contracts mature at various times and in varying amounts of entitlement. The Pipeline Companies manage the recontracting process to mitigate the risk of a significant negative impact on operating revenue.

Historically, the Pipeline Companies have been able to provide competitively priced services because of access to a variety of relatively low cost supply basins, cost control measures and the relatively high level of firm entitlement that is sold on a seasonal and annual basis, which lowers the per unit cost of transportation. To date, the Pipeline Companies have avoided significant pipeline system bypasses.

In December 2009, the FERC issued an order establishing revised rates for Kern River's initial long-term contracts ("Period One rates") and required that rates be established based on a levelized rate design for eligible customers that elect to take service following the expiration of their initial contracts ("Period Two rates"). The Period Two rates are lower because they are designed to recover only the remaining plant balances. Beginning in late 2011, certain of Kern River's contracts with Period One rates expired. To the extent that eligible customers elected not to contract for service at Period Two rates, the volumes were turned back and sold at market rates for varying terms. Of the customers that were eligible to take Period Two service beginning October 1, 2016, 97% elected to extend their contracts at maximum Period Two rates, with 184,528 Dth per day electing 10-year contracts and 410,763 Dth per day electing 15-year contracts. As of February 1, 2016, Kern River has sold 194,047 Dth per day of the total turned back volume of 259,503 Dth per day with an average remaining contract term of five years. The remaining turned back capacity is sold on a short term basis at market rates.

Northern Natural Gas needs to compete aggressively to serve existing load and add new load. Northern Natural Gas has been successful in competing for a significant amount of the increased demand related to residential and commercial needs and the construction of new power plants and new fertilizer or other industrial plants. The growth related to utilities has historically been driven by population growth and increased commercial and industrial needs. Northern Natural Gas has been generally successful in negotiating increased transportation rates for customers who received discounted service when such contract terms are renegotiated and extended.

Northern Natural Gas' major competitors in the Market Area include ANR Pipeline Company, Northern Border, Natural Gas Pipeline Company of America LLC, Great Lakes and Viking. In the Field Area, where the vast majority of Northern Natural Gas' capacity is used for transportation services provided on a short-term firm basis, Northern Natural Gas competes with a large number of interstate and intrastate pipeline companies.

Northern Natural Gas' attractive competitive position relative to other pipelines in the upper Midwest was reinforced during the colder than normal winter of 2013-2014. Northern Natural Gas' customers' ability to access multiple supply basins has been critical to customers managing their reliability and supply costs. Northern Natural Gas' Field Area has access to diverse Mid-Continent, Permian and Rockies supplies with resulting prices delivered to Market Area customers at Demarcation significantly less than their alternative supply source.

Northern Natural Gas expects the current level of Field Area contracting to continue in the foreseeable future, as Market Area customers presently need to purchase competitively-priced supplies from the Field Area to support their existing and growth demand requirements. However, the revenue received from these Field Area contracts is expected to vary in relationship to the difference, or "spread," in natural gas prices between the MidContinent and Permian Regions and the price of the alternative supplies that are available to Northern Natural Gas' Market Area. This spread affects the value of the Field Area transportation capacity because natural gas from the MidContinent and Permian Regions that is transported through Northern Natural Gas' Field Area competes directly with natural gas delivered directly into the Market Area from Canada and other supply areas, including new shale gas producing areas outside of the Field Area.

Kern River competes with various interstate pipelines in developing expansion projects and entering into long-term agreements to serve market growth in Southern California; Las Vegas, Nevada; and Salt Lake City, Utah. Kern River also competes with various interstate pipelines and their customers to market unutilized capacity under shorter term transactions. Kern River provides its customers with supply diversity through interconnections with pipelines such as Northwest Pipeline GP, Colorado Interstate Gas Company, Overland Trails Transmission, LLC, Questar Pipeline Company, and Questar Overthrust Pipeline Company; storage facilities such as Ryckman Creek Resources, LLC and Clear Creek Storage Company, LLC; and through indirect pipeline interconnections with Wyoming Interstate Company and REX. These interconnections, in addition to the direct interconnections to natural gas processing facilities, allow Kern River to access natural gas reserves in Colorado, northwestern New Mexico, Wyoming, Utah and the Western Canadian Sedimentary Basin.

Kern River is the only interstate pipeline that presently delivers natural gas directly from the Rocky Mountain gas supply region to end-users in the Southern California market. This enables direct connect customers to avoid paying a "rate stack" (i.e., additional transportation costs attributable to the movement from one or more interstate pipeline systems to an intrastate system within California). Kern River's levelized rate structure and access to upstream pipelines, storage facilities and economic Rocky Mountain gas reserves increases its competitiveness and attractiveness to end-users. Kern River believes it has an advantage relative to other interstate pipelines serving Southern California because its relatively new pipeline can be economically expanded and has required significantly less capital expenditures and ongoing maintenance than other systems to comply with the Pipeline Safety Improvement Act of 2002. Kern River's favorable market position is tied to the availability of gas reserves in the Rocky Mountain area, an area that in recent years has attracted considerable expansion of pipeline capacity serving markets other than Southern California and Nevada.

BHE TRANSMISSION

AltaLink

ALP, an indirect wholly owned subsidiary of BHE acquired on December 1, 2014, is a regulated electric transmission-only company headquartered in Alberta, Canada serving approximately 85% of Alberta's population. ALP connects generation plants to major load centers, cities and large industrial plants throughout its 87,000 square mile service territory, which covers a diverse geographic area including most major urban centers in central and southern Alberta. ALP's transmission facilities, consisting of approximately 8,100 miles of transmission lines and 300 substations as of December 31, 2015, are an integral part of the Alberta Integrated Electric System ("AIES").

The AIES is a network or grid of transmission facilities operating at high voltages ranging from 69kV to 500kV. The grid delivers electricity from generating units across Alberta, Canada through approximately 15,000 miles of transmission and over 600 substations. The AIES is interconnected to British Columbia's transmission system that links Alberta with the North American western interconnected system.

ALP is a transmission facility owner within the electricity industry in Alberta and is permitted to charge a tariff rate for the use of its transmission facilities. Such tariff rates are established on a cost-of-service basis, which are designed to allow ALP an opportunity to recover its costs of providing services and to earn a reasonable return on its investments. Transmission tariffs are approved by the AUC and are collected from the AESO.

The electricity industry in Alberta consists of four principal segments. Generators sell wholesale power into the power pool operated by the AESO and through direct contractual arrangements. Alberta's transmission system or grid is composed of high voltage power lines and related facilities that transmit electricity from generating facilities to distribution networks and directly connected end-users. Distribution facility owners are regulated by the AUC and are responsible for arranging for, or providing, regulated rate and regulated default supply services to convey electricity from transmission systems and distribution-connected generators to end-use customers. Retailers can procure energy through the power pool, through direct contractual arrangements with energy suppliers or ownership of generation facilities and arrange for its distribution to end-use customers.

In November 2015 the AESO finalized and made available the 2015 Long-Term Transmission Plan ("LTP"). The AESO mandate is defined in the Electric Utilities Act and its regulations, and requires the AESO to assess both current and future needs of Alberta’s interconnected electrical system. The 2015 LTP is based on the AESO's forecast of load and generation as documented in the 2014 Long Term Outlook ("LTO"). The AESO 2015 LTP recognizes the province's economic outlook has changed significantly since then. Current economic conditions have resulted in slower provincial growth. The AESO's current long range plan does not include any consideration for the Government of Alberta’s Climate Leadership Plan.

In its general tariff application for 2015 and 2016, filed November 2014, ALP forecasted C$1.5 billion and C$1.1 billion, respectively, gross direct assigned capital expenditures based on the long-range plan released by the AESO in January 2014, using a risk-adjusted capital forecasting model that has been previously accepted by the AUC. In October 2015, the forecast expenditures were updated to C$961 million for 2015 and C$538 million for 2016. ALP's actual capital program may vary from its regulatory filings, depending on the timing of regulatory approvals, directions from the AESO, and other factors beyond ALP's control.

BHE U.S. Transmission

BHE U.S. Transmission is engaged in various joint ventures to develop, own and operate transmission assets and is pursuing additional investment opportunities in the United States. Currently, BHE U.S. Transmission has two joint ventures with transmission assets that are operational.

BHE U.S. Transmission indirectly owns a 50% interest in ETT, along with subsidiaries of American Electric Power Company, Inc. ("AEP"). ETT owns and operates electric transmission assets in the ERCOT and, as of December 31, 2015, had total assets of $2.7 billion. ETT is regulated by the Public Utility Commission of Texas, which has approved rates based on a 9.96% after tax rate of return on equity and a debt to equity capital structure of 60:40. A total of $2.3 billion of transmission projects were in-service as of December 31, 2015, with $0.6 billion of projects forecast to be completed in 2016 through 2019. ETT's transmission system includes approximately 1,000 line miles of transmission and 30 substations as of December 31, 2015.

BHE U.S. Transmission indirectly owns a 25% interest in Prairie Wind Transmission, LLC, a joint venture with AEP and Westar Energy, Inc., to build, own and operate a 108-mile, 345 kV transmission project in Kansas. The necessary approvals from the FERC have been received, including a return on equity, inclusive of incentives, of 12.80% and a debt to equity capital structure of 50:50. The project cost $158 million and was fully placed in-service in November 2014.

BHE RENEWABLES

The subsidiaries comprising the BHE Renewables reportable segment own interests in 28 independent power projects that are in-service or under construction in the United States and one independent power project in the Philippines.

The following table presents certain information concerning these independent power projects as of December 31, 2015:

Generating Facility	Location	Energy Source	Installed	Power Purchase Agreement Expiration	Power Purchaser[1]	Facility Net Capacity (MW)[2]	Net Owned Capacity (MW)[2]
SOLAR:							
Topaz	California	Solar	2013-2014	2040	PG&E	550	550
Solar Star 1	California	Solar	2013-2015	2035	SCE	310	310
Solar Star 2	California	Solar	2013-2015	2035	SCE	276	276
Agua Caliente	Arizona	Solar	2012-2013	2039	PG&E	290	142
						1,426	1,278
WIND:							
Bishop Hill II	Illinois	Wind	2012	2032	Ameren	81	81
Pinyon Pines I	California	Wind	2012	2035	SCE	168	168
Pinyon Pines II	California	Wind	2012	2035	SCE	132	132
Jumbo Road	Texas	Wind	2015	2033	AE	300	300
						681	681
GEOTHERMAL:							
Imperial Valley Projects	California	Geothermal	1982-2000	(3)	(3)	338	338
HYDROELECTRIC:							
Casecnan Project[4]	Philippines	Hydroelectric	2001	2021	NIA	150	128
Wailuku	Hawaii	Hydroelectric	1993	2023	HELCO	10	10
						160	138
NATURAL GAS:							
Saranac	New York	Natural Gas	1994	2017	TEMUS	245	196
Power Resources	Texas	Natural Gas	1988	2018	EDF	212	212
Yuma	Arizona	Natural Gas	1994	2024	SDG&E	50	50
Cordova	Illinois	Natural Gas	2001	2019	EGC	512	512
						1,019	970
Total Available Generating Capacity						3,624	3,405
PROJECTS UNDER CONSTRUCTION:							
Grand Prairie	Nebraska	Wind	2016	2036	OPPD	400	400
Marshall	Kansas	Wind	2016	2036	MJMEC, KPP & COIMO	72	72
						472	472
						4,096	3,877

(1) TransAlta Energy Marketing U.S. ("TEMUS"); EDF Energy Services, LLC ("EDF"); San Diego Gas & Electric Company ("SDG&E"); Exelon Generation Company, LLC ("EGC"); Pacific Gas and Electric Company ("PG&E"), Ameren Illinois Company ("Ameren"), Southern California Edison ("SCE"), the Philippine National Irrigation Administration ("NIA"); Hawaii Electric Light Company, Inc. ("HELCO"); Austin Energy ("AE"); Omaha Public Power District ("OPPD"); U.S. General Services Administration ("USGSA"); Missouri Joint Municipal Electric Commission ("MJMEC"); Kansas Power Pool ("KPP"); and City of Independence, MO ("COIMO").

(2) 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 (in MW) under specified conditions. Net Owned Capacity indicates BHE Renewables' ownership of Facility Net Capacity.

(3) 82% of the Imperial Valley Projects' Contract Capacity is currently sold to Southern California Edison Company under long-term power purchase agreements expiring in 2016 through 2026. Certain long-term power purchase agreement renewals have been entered into with other parties that begin upon the existing contracts' expiration and expire in 2039.

(4) Under the terms of the agreement with the NIA, CalEnergy Philippines will own and operate the Casecnan project for a 20-year cooperation period which ends December 11, 2021, after which ownership and operation of the project will be transferred to the NIA at no cost on an "as-is" basis. NIA also pays CalEnergy Philippines for delivery of water pursuant to the agreement.

BHE Renewables' operating revenue is derived from the following business activities for the years ended December 31 (in millions):

	2015	2014	2013
Solar	$ 383	$ 238	$ 73
Wind	99	99	121
Geothermal	165	125	—
Hydro	23	107	129
Natural gas	58	54	32
Total operating revenue	$ 728	$ 623	$ 355

HOMESERVICES

HomeServices, a majority-owned subsidiary of BHE, is the second-largest full-service residential real estate brokerage firm in the United States. In addition to providing traditional residential real estate brokerage services, HomeServices offers other integrated real estate services, including mortgage originations and mortgage banking; title and closing services; property and casualty insurance; home warranties; relocation services; and other home-related services. HomeServices' real estate brokerage business is subject to seasonal fluctuations because more home sale transactions tend to close during the second and third quarters of the year. As a result, HomeServices' operating results and profitability are typically higher in the second and third quarters relative to the remainder of the year. HomeServices' owned brokerages currently operate in over 475 offices in 27 states with over 26,000 sales associates under 31 brand names. The United States residential real estate brokerage business is subject to the general real estate market conditions, is highly competitive and consists of numerous local brokers and agents in each market seeking to represent sellers and buyers in residential real estate transactions. In October 2014, HomeServices acquired the remaining 50.1% of HomeServices Lending, a mortgage origination company.

In October 2012, HomeServices acquired a 66.7% interest in one of the largest residential real estate brokerage franchise networks in the United States, which offers and sells independently owned and operated residential real estate brokerage franchises. The noncontrolling interest member has the right to put the remaining 33.3% interest in the franchise business to HomeServices after March 2015 and HomeServices has the right to purchase the remaining 33.3% interest in the franchise business after March 2018 at an option exercise formula based on historical financial performance.

HomeServices' franchise network currently includes over 400 franchisees in over 1,400 brokerage offices in 48 states with over 44,000 sales associates under three brand names. In exchange for certain fees, HomeServices provides the right to use the Berkshire Hathaway HomeServices, Prudential or Real Living brand names and other related service marks, as well as providing orientation programs, training and consultation services, advertising programs and other services. In 2013, HomeServices began rebranding certain of its Prudential franchisees as Berkshire Hathaway HomeServices and as of December 31, 2015, over 220 franchisees of the original 330 identified Prudential brokers, representing 83% of the 2012 revenue, had been rebranded.

GENERAL REGULATION

BHE's regulated subsidiaries and certain affiliates are subject to comprehensive governmental regulation, which significantly influences their operating environment, prices charged to customers, capital structure, costs and, ultimately, their ability to recover costs. In addition to the discussion contained herein regarding general regulation, refer to "Regulatory Matters" in Item 1 of this Form 10-K for further discussion regarding certain regulatory matters.

Domestic Regulated Public Utility Subsidiaries

The Utilities are subject to comprehensive regulation by various federal, state and local agencies. The more significant aspects of this regulatory framework are described below.

State Regulation

Historically, state regulatory commissions have established retail electric and natural gas 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 cost of sales, operating expense, 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.

The retail electric rates of the Utilities are generally based on the cost of providing traditional bundled services, including generation, transmission and distribution services. The Utilities have established energy cost adjustment mechanisms and other cost recovery mechanisms in certain states, which help mitigate their exposure to changes in costs from those assumed in establishing base rates.

With certain limited exceptions, the Utilities have an exclusive right to serve retail customers within their service territories and, in turn, have an 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. In Illinois, state law has established a competitive environment so that all Illinois customers are free to choose their retail service supplier. For customers that choose an alternative retail energy supplier, MidAmerican Energy continues to have an ongoing obligation to deliver the supplier's energy to the retail customer. MidAmerican Energy bills the retail customer for such delivery services. MidAmerican Energy also has an obligation to serve customers at regulated cost-based rates and has a continuing obligation to serve customers who have not selected a competitive electricity provider. To date, there has been no significant loss of customers in Illinois. In Nevada, state law allows retail electric customers with an average annual load of one MW or more to file a letter of intent and application with the PUCN to acquire electric energy and ancillary services from another energy supplier. The law requires customers wishing to choose a new supplier to receive the approval of the PUCN to meet public interest standards. In particular, departing customers must secure new energy resources that are not under contract to the Nevada Utilities, the departure must not burden the Nevada Utilities with increased costs or cause any remaining customers to pay increased costs, and the departing customers must pay their portion of any deferred energy balances. Also, the Utilities are individually evaluating how best to integrate distributed generation resources into their 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.

Also in Nevada, large natural gas customers using 12,000 therms per month with fuel switching capability are allowed by tariff to participate in the incentive natural gas rate tariff. Once a service agreement has been executed, a customer can compare natural gas prices under this tariff to alternative energy sources and choose its source of natural gas. In addition, natural gas customers using greater than 1,000 therms per day have the ability to secure their own natural gas supplies under the gas transportation tariff.

PacifiCorp

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. Wheeling revenue is also included in the mechanism. Balancing account to provide for 100% recovery or refund of the difference between the level of REC revenues included in base rates and actual REC revenues after adjusting for a REC incentive authorized by the UPSC. 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. Chemical costs and start-up fuel costs are also included in the mechanism starting in 2016. 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 in rates.
WUTC	Historical with known and measurable changes	PCAM under which 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 after applying a $4 million deadband for positive or negative net power cost variances. For net power cost variances between $4 million and $10 million, amounts to be recovered from customers are allocated 50/50 and amounts to be credited to customers are allocated 75/25 (customers/ PacifiCorp). Positive or negative net power cost variances in excess of $10 million are allocated 90/10 (customers/PacifiCorp). 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 credit of 100% 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 differences in actual production tax credits compared to the amount in base rates.
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 power costs. PTAM for attrition, a mechanism that allows for an annual adjustment to costs other than net power costs.

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

MidAmerican Energy

Under Iowa law, there are two options for temporary collection of higher rates following the filing of a request for a base rate increase. Collection can begin, subject to refund, either (1) within 10 days of filing, without IUB review, or (2) 90 days after filing, with approval by the IUB, depending upon the ratemaking principles and precedents utilized. In either case, if the IUB has not issued a final order within ten months after the filing date, the temporary rates become final and any difference between the requested rate increase and the temporary rates may then be collected subject to refund until receipt of a final order. Under Illinois law, new base rates may become effective 45 days after the filing of a request with the ICC, or earlier with ICC approval. The ICC has authority to suspend the proposed new rates, subject to hearing, for a period not to exceed approximately eleven months after filing. South Dakota law authorizes the SDPUC to suspend new base rates for up to six months during the pendency of rate proceedings; however, a utility may implement all or a portion of the proposed new rates six months after the filing of a request for a rate increase subject to refund pending a final order in the proceeding.

Iowa law also permits rate-regulated utilities to seek ratemaking principles with the IUB prior to the construction of certain types of new generating facilities. Pursuant to this law, MidAmerican Energy has applied for and obtained IUB ratemaking principles orders for a 484-MW (MidAmerican Energy's share) coal-fueled generating facility, a 495-MW combined cycle natural gas-fueled generating facility and 4,048 MW (nominal ratings) of wind-powered generating facilities, including 599 MW (nominal ratings) under construction, as of December 31, 2015. These ratemaking principles established cost caps for the projects and authorized a fixed rate of return on equity for the respective generating facilities over the regulatory life of the facilities in any future Iowa rate proceeding. As of December 31, 2015, the generating facilities in-service totaled $4.9 billion, or 42%, of MidAmerican Energy's regulated property, plant and equipment, net, and were subject to these ratemaking principles at a weighted average return on equity of 11.9% with a weighted average remaining life of 24 years.

Under its current Iowa, Illinois and South Dakota electric tariffs, MidAmerican Energy is allowed to recover fluctuations in electric energy costs for its retail electric generation through fuel, or energy, cost adjustment mechanisms. The Iowa mechanism also includes production tax credits associated with wind-powered generation placed in-service prior to 2013. Eligibility for production tax credits associated with MidAmerican Energy's earliest projects began expiring in 2014. Additionally, MidAmerican Energy has transmission adjustment clauses to recover certain transmission charges related to retail customers in Iowa and Illinois. The adjustment mechanisms reduce the regulatory lag for the recovery of energy and transmission costs related to retail electric customers in these jurisdictions.

Of the wind-powered generating facilities placed in-service as of December 31, 2015, 1,212 MW (nominal ratings) have not been included in the determination of MidAmerican Energy’s Iowa retail electric base rates. In accordance with the related ratemaking principles, until such time as these generation assets are reflected in rates and ceasing thereafter, MidAmerican Energy is to reduce its Iowa energy adjustment clause recoveries by $5 million in 2015, $9 million in 2016 and $12 million for each calendar year thereafter.

MidAmerican Energy's cost of gas is collected for each jurisdiction in its gas rates through a uniform PGA, which is updated monthly to reflect changes in actual costs. Subject to prudence reviews, the PGA accomplishes a pass-through of MidAmerican Energy's cost of gas to its customers and, accordingly, has no direct effect on net income. MidAmerican Energy's DSM program costs are collected through separately established rates that are adjusted annually based on actual and expected costs, as approved by the respective state regulatory commission. As such, recovery of DSM program costs has no direct impact on net income.

NV Energy (Nevada Power and Sierra Pacific)

Nevada statutes require the Nevada Utilities to file electric general rate cases at least once every three years with the PUCN. Sierra Pacific may also file natural gas general rate cases with the PUCN. The Nevada Utilities are also subject to a two-part fuel and purchased power adjustment mechanism. The Nevada Utilities make quarterly filings to reset BTER, based on the last 12 months of fuel and purchased power costs. The difference between actual fuel and purchased power costs and the revenue collected in the BTER is deferred into a balancing account. During required annual DEAA proceedings, the prudence of fuel and purchased power costs is reviewed, and if any costs are disallowed on such grounds, the disallowances will be incorporated into the next subsequent quarterly BTER rate change. Additionally, Nevada regulations allow an electric or natural gas utility that adjusts its BTER on a quarterly basis to request PUCN approval to make quarterly changes to its DEAA rate if the request is in the public interest. The Nevada Utilities received approval from the PUCN and file quarterly adjustments to the DEAA rate to clear amounts deferred into the balancing account. At the same time the Nevada Utilities make the annual DEAA filing, they also (a) seek a determination that energy efficiency program expenditures were reasonable, (b) request that the PUCN reset base and amortization energy efficiency program rates, and (c) request that the Commission reset base and energy efficiency implementation (formerly lost revenue) rates. When the Nevada Utilities’ earned rate of return for a calendar year exceeds the rate of return used to set base tariff general rates, they are obligated to refund energy efficiency implementation revenue previously collected for that year.

Federal Regulation

The FERC is an independent agency with broad authority to implement provisions of the Federal Power Act, the Natural Gas Act ("NGA"), the Energy Policy Act of 2005 ("Energy Policy Act") and other federal statutes. The FERC regulates rates for wholesale sales of electricity; transmission of electricity, including pricing and regional planning for the expansion of transmission systems; electric system reliability; utility holding companies; accounting and records retention; securities issuances; construction and operation of hydroelectric facilities; 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. The Utilities have implemented programs and procedures that facilitate and monitor compliance with the FERC's regulations described below. MidAmerican Energy is also subject to regulation by the NRC pursuant to the Atomic Energy Act of 1954, as amended ("Atomic Energy Act"), with respect to its ownership interest in the Quad Cities Station.

Wholesale Electricity and Capacity

The FERC regulates the Utilities' rates charged to wholesale customers for electricity and transmission capacity and related services. Most of the Utilities' wholesale electricity sales and purchases occur under market-based pricing allowed by the FERC and are therefore subject to market volatility.

The Utilities' authority to sell electricity in wholesale electricity markets at market-based rates is subject to triennial reviews conducted by the FERC. Accordingly, the Utilities are required to submit triennial filings to the FERC that demonstrate a lack of market power over sales of wholesale electricity and electric generation capacity in their respective market areas. PacifiCorp's most recent triennial filing was made in June 2013 and is currently pending before the FERC. 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 the Utilities, show cause why their market-based rate authority remains just and reasonable following BHE's acquisition of NV Energy. This proceeding, which is focused on the western interconnection, remains ongoing. MidAmerican Energy's most recent triennial filings were submitted in June 2014 for the FERC-defined Northeast Region and December 2014 for the FERC-defined Central Region. The June 2014 triennial filing was accepted by the FERC in January 2015, and the December 2014 triennial filing was accepted by the FERC in November 2015. The Nevada Utilities' most recent triennial filing was made in July 2013 and approved by the FERC in April 2014. In July 2016, the Nevada Utilities plan to make their triennial filing. Under the FERC's market-based rules, the Utilities 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.

Transmission

PacifiCorp's and the Nevada Utilities' wholesale transmission services are regulated by the FERC under cost-based regulation subject to PacifiCorp's and the Nevada Utilities' OATT, respectively. 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 and the Nevada Utilities' transmission business is managed and operated independently from its wholesale marketing business in accordance with the FERC's Standards of Conduct. PacifiCorp and the Nevada Utilities have 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 energy supply management function.

MidAmerican Energy participates in the MISO as a transmission-owning member. Accordingly, the MISO is the transmission provider under its FERC-approved OATT. While the MISO is responsible for directing the operation of MidAmerican Energy's transmission system, MidAmerican Energy retains ownership of its transmission assets and, therefore, is subject to the FERC's reliability standards discussed below. MidAmerican Energy's transmission business is managed and operated independently from its wholesale marketing business in accordance with the FERC Standards of Conduct.

MidAmerican Energy has approval from the MISO to construct and own four Multi-Value Projects ("MVPs") located in Iowa and Illinois that will add approximately 245 miles of 345 kV transmission line to MidAmerican Energy's transmission system. The MISO OATT allows for broad cost allocation for MidAmerican Energy's MVPs, including similar MVPs of other MISO participants. Accordingly, a significant portion of the revenue requirement associated with MidAmerican Energy's MVP investments will be shared with other MISO participants based on the MISO's cost allocation methodology and a portion of the revenue requirement of the other participants' MVPs will be allocated to MidAmerican Energy. Additionally, MidAmerican Energy has approval from the FERC to include 100% of construction work in progress in the determination of rates for its MVPs and to use a forward-looking rate structure for all of its transmission investments and costs. The transmission assets and financial results of MidAmerican Energy's MVPs are excluded from the determination of its retail electric rates.

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 for PacifiCorp, Nevada Power and Sierra Pacific and the Midwest Reliability Organization for MidAmerican Energy.

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, 16 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 utilized by PacifiCorp in development of public safety programs consisting of a 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 16 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K and Note 13 of the Notes to Consolidated Financial Statements of PacifiCorp in Item 8 of this Form 10-K for an update regarding hydroelectric relicensing for PacifiCorp's Klamath River hydroelectric system.

Nuclear Regulatory Commission

General

MidAmerican Energy is subject to the jurisdiction of the NRC with respect to its license and 25% ownership interest in Quad Cities Station. Exelon Generation, the operator and 75% owner of Quad Cities Station, is under contract with MidAmerican Energy to secure and keep in effect all necessary NRC licenses and authorizations.

The NRC regulates the granting of permits and licenses for the construction and operation of nuclear generating stations and regularly inspects such stations for compliance with applicable laws, regulations and license terms. Current licenses for Quad Cities Station provide for operation until December 14, 2032. The NRC review and regulatory process covers, among other things, operations, maintenance, and environmental and radiological aspects of such stations. The NRC may modify, suspend or revoke licenses and impose civil penalties for failure to comply with the Atomic Energy Act, the regulations under such Act or the terms of such licenses.

Federal regulations provide that any nuclear operating facility may be required to cease operation if the NRC determines there are deficiencies in state, local or utility emergency preparedness plans relating to such facility, and the deficiencies are not corrected. Exelon Generation has advised MidAmerican Energy that an emergency preparedness plan for Quad Cities Station has been approved by the NRC. Exelon Generation has also advised MidAmerican Energy that state and local plans relating to Quad Cities Station have been approved by the Federal Emergency Management Agency.

The NRC also regulates the decommissioning of nuclear powered generating facilities, including the planning and funding for the eventual decommissioning of the facilities. In accordance with these regulations, MidAmerican Energy submits a biennial report to the NRC providing reasonable assurance that funds will be available to pay its share of the costs of decommissioning Quad Cities Station. MidAmerican Energy has established a trust for the investment of funds collected for nuclear decommissioning of Quad Cities Station. The decommissioning costs are included in base rates in MidAmerican Energy's Iowa tariffs.

Under the Nuclear Waste Policy Act of 1982 ("NWPA"), the U.S. Department of Energy ("DOE") is responsible for the selection and development of repositories for, and the permanent disposal of, spent nuclear fuel and high-level radioactive wastes. Exelon Generation, as required by the NWPA, signed a contract with the DOE under which the DOE was to receive spent nuclear fuel and high-level radioactive waste for disposal beginning not later than January 1998. The DOE did not begin receiving spent nuclear fuel on the scheduled date and remains unable to receive such fuel and waste. The costs to be incurred by the DOE for disposal activities were previously being financed by fees charged to owners and generators of the waste. In accordance with a 2013 ruling by the United States Court of Appeals for the District of Columbia Circuit ("D.C. Circuit"), the DOE, in May 2014, provided notice that, effective May 16, 2014, the spent nuclear fuel disposal fee would be zero. In 2004, Exelon Generation, reached a settlement with the DOE concerning the DOE's failure to begin accepting spent nuclear fuel in 1998. As a result, Quad Cities Station has been billing the DOE, and the DOE is obligated to reimburse the station for all station costs incurred due to the DOE's delay. Exelon Generation has completed construction of an interim spent fuel storage installation ("ISFSI") at Quad Cities Station to store spent nuclear fuel in dry casks in order to free space in the storage pool. The first pad at the ISFSI is expected to facilitate storage of casks to support operations at Quad Cities Station until at least 2020. The first storage in a dry cask commenced in November 2005. By 2020, Exelon Generation plans to add a second pad to the ISFSI to accommodate storage of spent nuclear fuel through the end of operations at Quad Cities Station.

Nuclear Insurance

MidAmerican Energy maintains financial protection against catastrophic loss associated with its interest in Quad Cities Station through a combination of insurance purchased by Exelon Generation, insurance purchased directly by MidAmerican Energy, and the mandatory industry-wide loss funding mechanism afforded under the Price-Anderson Amendments Act of 1988, which was amended and extended by the Energy Policy Act. The general types of coverage maintained are: nuclear liability, property damage or loss and nuclear worker liability, as discussed below.

Exelon Generation purchases private market nuclear liability insurance for Quad Cities Station in the maximum available amount of $375 million, which includes coverage for MidAmerican Energy's ownership. In accordance with Price-Anderson, excess liability protection above that amount is provided by a mandatory industry-wide Secondary Financial Protection program under which the licensees of nuclear generating facilities could be assessed for liability incurred due to a serious nuclear incident at any commercial nuclear reactor in the United States. Currently, MidAmerican Energy's aggregate maximum potential share of an assessment for Quad Cities Station is approximately $64 million per incident, payable in installments not to exceed $10 million annually.

The property insurance covers property damage, stabilization and decontamination of the facility, disposal of the decontaminated material and premature decommissioning arising out of a covered loss. For Quad Cities Station, Exelon Generation purchases primary and excess property insurance protection for the combined interests in Quad Cities Station, with coverage limits totaling $2.1 billion. MidAmerican Energy also directly purchases extra expense coverage for its share of replacement power and other extra expenses in the event of a covered accidental outage at Quad Cities Station. The property and related coverages purchased directly by MidAmerican Energy and by Exelon Generation, which includes the interests of MidAmerican Energy, are underwritten by an industry mutual insurance company and contain provisions for retrospective premium assessments to be called upon based on the industry mutual board of directors' discretion for adverse loss experience. Currently, the maximum retrospective amounts that could be assessed against MidAmerican Energy from industry mutual policies for its obligations associated with Quad Cities Station total $9 million.

The master nuclear worker liability coverage, which is purchased by Exelon Generation for Quad Cities Station, is an industry-wide guaranteed-cost policy with an aggregate limit of $375 million for the nuclear industry as a whole, which is in effect to cover tort claims of workers in nuclear-related industries.

United States Mine Safety

PacifiCorp's mining operations are regulated by the Federal Mine Safety and Health Administration, which administers federal mine safety and health laws and regulations, and state regulatory agencies. The Federal Mine Safety and Health Administration 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 the Federal Mine Safety and Health Administration 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.

Interstate Natural Gas Pipeline Subsidiaries

The Pipeline Companies are regulated by the FERC, pursuant to the NGA and the Natural Gas Policy Act of 1978. Under this authority, the FERC regulates, among other items, rates; charges; terms and conditions of service; and the construction and operation of interstate pipelines, storage and related facilities, including the extension, expansion or abandonment of such facilities. The Pipeline Companies hold certificates of public convenience and necessity issued by the FERC, which authorize them to construct, operate and maintain their pipeline and related facilities and services.

FERC regulations and the Pipeline Companies' tariffs allow each of the Pipeline Companies to charge approved rates for the services set forth in their respective tariff. Generally, these rates are a function of the cost of providing services to their customers, including prudently incurred operations and maintenance expenses, taxes, interest, depreciation and amortization and a reasonable return on their investments. Both Northern Natural Gas' and Kern River's tariff rates have been developed under a rate design methodology whereby substantially all of their fixed costs, including a return on invested capital and income taxes, are collected through reservation charges, which are paid by firm transportation and storage customers regardless of volumes shipped. Commodity charges, which are paid only with respect to volumes actually shipped, are designed to recover the remaining, primarily variable, costs. Kern River's reservation rates have historically been approved using a "levelized" cost-of-service methodology so that the rate remains constant over the levelization period. This levelized cost of service has been achieved by using a FERC-approved depreciation schedule in which depreciation increases as interest expense and return on equity amounts decrease. Both Northern Natural Gas' and Kern River's rates are subject to change in future general rate proceedings.

Natural gas transportation companies may not grant any undue preference to any customer. FERC regulations also restrict each pipeline's marketing affiliates' access to certain non-public information regarding their affiliated interstate natural gas transmission pipelines.

Interstate natural gas pipelines are also subject to regulations administered by the Office of Pipeline Safety within the Pipeline and Hazardous Materials Safety Administration, an agency within the United States Department of Transportation ("DOT"). Federal pipeline safety regulations are issued pursuant to the Natural Gas Pipeline Safety Act of 1968, as amended ("NGPSA"), which establishes safety requirements in the design, construction, operation and maintenance of interstate natural gas facilities, and requires an entity that owns or operates pipeline facilities to comply with such plans. Major amendments to the NGPSA include the Pipeline Safety Improvement Act of 2002 ("2002 Act"), the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 ("2006 Act") and the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 ("2011 Act").

The 2002 Act established additional safety and pipeline integrity regulations for all natural gas pipelines in high-consequence areas. The 2002 Act imposed major new requirements in the areas of operator qualifications, risk analysis and integrity management. The 2002 Act mandated more frequent periodic inspection or testing of natural gas pipelines in high-consequence areas, which are locations where the potential consequences of a natural gas pipeline accident may be significant or may do considerable harm to persons or property. Pursuant to the 2002 Act, the DOT promulgated new regulations that require natural gas pipeline operators to develop comprehensive integrity management programs, to identify applicable threats to natural gas pipeline segments that could impact high-consequence areas, to assess these segments, and to provide ongoing mitigation and monitoring. The regulations required that all baseline high-consequence area segments be assessed by December 17, 2012 and require recurring inspections every seven years thereafter. Based on the Pipeline Companies' extensive compliance efforts, they have completed all required high-consequence area pipeline baseline integrity assessments. Kern River also completed the required in-line inspections in early 2011 on that portion of its pipeline system required by the conditions associated with a special permit which allowed for an increase to the maximum allowable operating pressure.

The 2006 Act required pipeline operators to institute human factors management plans for personnel employed in pipeline control centers. DOT regulations published pursuant to the 2006 Act required development and implementation of written control room management procedures.

The 2011 Act was a response to natural gas pipeline incidents, most notably the San Bruno natural gas pipeline explosion that occurred in September 2010 in California. The 2011 Act increased the maximum allowable civil penalties for violations, directs operator assistance for Federal authorities conducting investigations and authorized the DOT to hire additional inspection and enforcement personnel. The 2011 Act also directed the DOT to study several topics, including the definition of high-consequence areas, the use of automatic shutoff valves in high-consequence areas, expansion of integrity management requirements beyond high-consequence areas, and cast iron pipe replacement. The studies are complete, and the BHE Pipeline Group anticipate notices of proposed rules at some point in 2016 on each of the areas studied. The BHE Pipeline Group cannot currently assess the potential cost of compliance with new rules and regulations under the 2011 Act.

The DOT and related state agencies routinely audit and inspect the pipeline facilities for compliance with their regulations. The Pipeline Companies conduct internal audits of their facilities every four years; with more frequent reviews of those deemed higher risk. The Pipeline Companies also conduct preliminary audits in advance of agency audits. Compliance issues that arise during these audits or during the normal course of business are addressed on a timely basis. The Pipeline Companies believe their pipeline systems comply in all material respects with the NGPSA and with DOT regulations issued pursuant to the NGPSA.

Northern Powergrid Distribution Companies

The Northern Powergrid Distribution Companies, as holders of electricity distribution licenses, are subject to regulation by GEMA. GEMA regulates distribution network operators ("DNOs") within the terms of the Electricity Act 1989 and the terms of DNO licenses, which are revocable with 25 years notice. Under the Electricity Act 1989, GEMA has a duty to ensure that DNOs can finance their regulated activities and DNOs have a duty to maintain an investment grade credit rating. GEMA discharges certain of its duties through its staff within Ofgem. Each of fourteen licensed DNOs distributes electricity from the national grid transmission system to end users within its respective distribution services area.

DNOs are subject to price controls, enforced by Ofgem, that limit the revenue that may be recovered and retained from their electricity distribution activities. The regulatory regime that has been applied to electricity distributors in Great Britain encourages companies to look for efficiency gains in order to improve profits. The distribution price control formula also adjusts the revenue received by DNOs to reflect a number of factors, including, but not limited to, the rate of inflation (as measured by the United Kingdom's Retail Prices Index) and the quality of service delivered by the licensee's distribution system. The current price control, Electricity Distribution 1 ("ED1"), has been set for a period of eight years, starting April 1, 2015, although the formula has been, and may be, reviewed by the regulator following public consultation. The procedure and methodology adopted at a price control review are at the reasonable discretion of Ofgem. Ofgem's judgment of the future allowed revenue of licensees is likely to take into account, among other things:

- the actual operating and capital costs of each of the licensees;
- the operating and capital costs that each of the licensees would incur if it were as efficient as, in Ofgem's judgment, the more efficient licensees;
- the actual value of certain costs which are judged to be beyond the control of the licensees;
- the taxes that each licensee is expected to pay;
- the regulatory value ascribed to the expenditures that have been incurred in the past and the efficient expenditures that are to be incurred in the forthcoming regulatory period;
- the rate of return to be allowed on expenditures that make up the regulatory asset value;
- the financial ratios of each of the licensees and the license requirement for each licensee to maintain investment grade status;
- an allowance in respect of the repair of the pension deficits in the defined benefit pension schemes sponsored by each of the licensees; and
- any under- or over-recoveries of revenues, relative to allowed revenues, in the previous price control period.

A number of incentive schemes also operate within the current price control period to encourage DNOs to provide an appropriate quality of service to end users. This includes specified payments to be made for failures to meet prescribed standards of service. The aggregate of these guaranteed standards payments is uncapped, but may be excused in certain prescribed circumstances that are generally beyond the control of the DNO.

A new price control can be implemented by GEMA without the consent of the DNO, but if a licensee disagrees with a change to its license it can appeal the matter to the United Kingdom's Competition and Markets Authority ("CMA"), as can certain other parties. Any appeals must be notified within 20 working days of the license modification by GEMA. If the CMA determines that the appellant has relevant standing, then the statute requires that the CMA complete its process within six months, or in some exceptional circumstances seven months. The Northern Powergrid Distribution Companies appealed Ofgem's proposals for the resetting of the formula that commenced April 1, 2015, as did one other party, and the CMA subsequently revised GEMA's decision.

The current electricity distribution price control became effective April 1, 2015 and is due to terminate on March 31, 2023, and will be immediately replaced with a new price control (in line with GEMA's current timetable). This price control is the first to be set for electricity distribution in Great Britain since Ofgem completed its review of network regulation (known as the RPI-X @ 20 project). The key changes to the price control calculations, compared to those used in previous price controls are that:

- the period over which new regulatory assets are depreciated is being gradually lengthened, from 20 years to 45 years, with the change being phased over eight years;
- allowed revenues will be adjusted during the price control period, rather than at the next price control review, to partially reflect cost variances relative to cost allowances;
- the allowed cost of debt will be updated within the price control period by reference to a long-run trailing average based on external benchmarks of utility debt costs;
- allowed revenues will be adjusted in relation to some new service standard incentives, principally relating to speed and service standards for new connections to the network; and
- there is scope for a mid-period review and adjustment to revenues in the latter half of the period for any changes in the outputs required of licensees for certain specified reasons.

Under the price control, as revised by the CMA, and excluding the effects of incentive schemes and any deferred revenues from the prior price control, the base allowed revenue of Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc decreased by approximately 0.1% and 0.2%, respectively, in 2016-17 and in all subsequent years within the price control period (RIIO-ED1), before the addition of inflation (as measured by the United Kingdom's Retail Prices Index). Base allowed revenue in 2015-16 remains unchanged from the price control final settlement. Nominal base allowed revenues will increase in line with inflation.

Ofgem also monitors DNO compliance with license conditions and enforces the remedies resulting from any breach of condition. License conditions include the prices and terms of service, financial strength of the DNO, the provision of information to Ofgem and the public, as well as maintaining transparency, non-discrimination and avoidance of cross-subsidy in the provision of such services. Ofgem also monitors and enforces certain duties of a DNO set out in the Electricity Act 1989, including the duty to develop and maintain an efficient, coordinated and economical system of electricity distribution. Under changes to the Electricity Act 1989 introduced by the Utilities Act 2000, GEMA is able to impose financial penalties on DNOs that contravene any of their license duties or certain of their duties under the Electricity Act 1989, as amended, or that are failing to achieve a satisfactory performance in relation to the individual standards prescribed by GEMA. Any penalty imposed must be reasonable and may not exceed 10% of the licensee's revenue.

ALP Transmission

ALP is regulated by the AUC, pursuant to the Electric Utilities Act (Alberta), the Public Utilities Act (Alberta), the Alberta Utilities Commission Act (Alberta) and the Hydro and Electric Energy Act (Alberta). The AUC is an independent, quasi-judicial agency established by the province of Alberta, Canada, which is responsible for, among other things, approving the tariffs of transmission facility owners, including ALP, and distribution utilities, acquisitions of such transmission facility owners or utilities, and construction and operation of new transmission projects in Alberta. The AUC also investigates and rules on regulated rate disputes and system access problems. The AUC regulates and oversees Alberta's electricity transmission sector with broad authority that may impact many of ALP's activities, including its tariffs, rates, construction, operations and financing.

The AUC has various core functions in regulating the Alberta electricity transmission sector, including the following:

- regulating and adjudicating issues related to the operation of electric utilities within Alberta;
- processing and approving general tariff applications relating to revenue requirements and rates of return including deemed capital structure for regulated utilities while ensuring that utility rates are just and reasonable and approval of the transmission tariff rates of regulated transmission providers paid by the AESO, which is the independent transmission system operator in Alberta, Canada that controls the operation of ALP's transmission system;
- approving the need for new electricity transmission facilities and permits to build and licenses to operate electricity transmission facilities;
- reviewing operations and accounts from electric utilities and conducting on-site inspections to ensure compliance with industry regulation and standards;
- adjudicating enforcement issues including the imposition of administrative penalties that arise when market participants violate the rules of the AESO; and
- collecting, storing, analyzing, appraising and disseminating information to effectively fulfill its duties as an industry regulator.

ALP's tariffs are regulated by the AUC under the provisions of the Electric Utilities Act in respect of rates and terms and conditions of service. The Electric Utilities Act and related regulations require the AUC to consider that it is in the public interest to provide consumers the benefit of unconstrained transmission access to competitive generation and the wholesale electricity market. In regulating transmission tariffs, the AUC must facilitate sufficient investment to ensure the timely upgrade, enhancement or expansion of transmission facilities, and foster a stable investment climate and a continued stream of capital investment for the transmission system.

Under the Electric Utilities Act, ALP prepares and files applications with the AUC for approval of tariffs to be paid by the AESO for the use of its transmission facilities, and the terms and conditions governing the use of those facilities. The AUC reviews and approves such tariff applications based on a cost-of-service regulatory model under a forward test year basis. Under this model, the AUC provides ALP with a reasonable opportunity to (i) earn a fair return on equity; and (ii) recover its forecast costs, including operating expenses, depreciation, borrowing costs and taxes associated with its regulated transmission business. The AUC must approve tariffs that are just, reasonable, and not unduly preferential, arbitrary or unjustly discriminatory. ALP's transmission tariffs are not dependent on the price or volume of electricity transported through its transmission system.

The AESO is an independent system operator in Alberta, Canada that oversees the AIES and wholesale electricity market. The AESO is responsible for directing the safe, reliable and economic operation of the AIES, including long-term transmission system planning. ALP and the other transmission facility owners receive substantially all of their transmission tariff revenues from the AESO. The AESO, in turn, charges wholesale tariffs, approved by the AUC, in a manner that promotes fair and open access to the AIES and facilitates a competitive market for the purchase and sale of electricity. The AESO monitors compliance with approved reliability standards, which are enforced by the Market Surveillance Administrator, which may impose penalties on transmission facility owners for non-compliance with the approved reliability standards.

The AESO determines the need and plans for the expansion and enhancement of a congestion free transmission system in Alberta in accordance with applicable law and reliability standards. The AESO's responsibilities include long-term transmission planning and management, including assessing and planning for the current and future transmission system capacity needs of AESO market participants. When AESO determines an expansion or enhancement of the transmission system is needed, with limited exceptions, it submits an application to the AUC for approval of the proposed expansion or enhancement. The AESO then determines which transmission provider should submit an application to the AUC for a permit and license to construct and operate the designated transmission facilities. Generally the transmission provider operating in the geographic area where the transmission facilities expansion or enhancement is to be located is selected by the AESO to build, own and operate the transmission facilities. In addition, Alberta law provides that certain transmission projects may be subject to a competitive process open to qualified bidders.

Independent Power Projects

The Yuma, Cordova, Saranac, Power Resources, Topaz, Agua Caliente, Solar Star, Bishop Hill II, Jumbo Road, Marshall and Pinyon Pines independent power projects are Exempt Wholesale Generators ("EWG") under the Energy Policy Act while the Imperial Valley and Wailuku independent power projects are currently certified as Qualifying Facilities ("QF") under the Public Utility Regulatory Policies Act of 1978. Both EWGs and QFs are generally exempt from compliance with extensive federal and state regulations that control the financial structure of an electric generating plant and the prices and terms at which electricity may be sold by the facilities. In addition, the Cordova, Saranac, Yuma, Imperial Valley, Topaz, Agua Caliente, Solar Star, Bishop Hill II and Pinyon Pines independent power projects have obtained authority from the FERC to sell their power using market-based rates. Jumbo Road's entire output is dedicated to its offtaker within the Electric Reliability Council of Texas ("ERCOT") and does not require market-based authority for such sales solely within ERCOT as the ERCOT market is not a FERC-jurisdictional market. Similarly, Wailuku sells its output solely to the Hawaii Electric Company within the Hawaii electric grid which is not a FERC-jurisdictional market and Wailuku therefore does not require market-based rate authority.

EWGs are permitted to sell capacity and electricity only in the wholesale markets, not to end users. Additionally, utilities are required to purchase electricity produced by QFs at a price that does not exceed the purchasing utility's "avoided cost" and to sell back-up power to the QFs on a non-discriminatory basis, unless they have successfully petitioned the FERC for an exemption from this purchase requirement. Avoided cost is defined generally as the price at which the utility could purchase or produce the same amount of power from sources other than the QF on a long-term basis. The Energy Policy Act eliminated the purchase requirement for utilities with respect to new contracts under certain conditions. New QF contracts are also subject to FERC rate filing requirements, unlike QF contracts entered into prior to the Energy Policy Act. FERC regulations also permit QFs and utilities to negotiate agreements for utility purchases of power at rates other than the utilities' avoided cost.

The Philippine Congress has passed the Electric Power Industry Reform Act of 2001 ("EPIRA"), which is aimed at restructuring the Philippine power industry, privatizing the National Power Corporation and introducing a competitive electricity market, among other initiatives. The implementation of EPIRA may impact future operations in the Philippines and the Philippine power industry as a whole, the effect of which is not yet known as changes resulting from EPIRA are ongoing.

Residential Real Estate Brokerage Company

HomeServices is regulated by the United States Bureau of Consumer Financial Protection under the Truth In Lending Act ("TILA") and the Real Estate Settlement Procedures Act ("RESPA"); the United States Federal Trade Commission with respect to certain franchising activities; and by state agencies where it operates. TILA primarily governs the real estate lending process by mandating lenders to fully inform borrowers about loan costs. RESPA primarily governs the real estate settlement process by mandating all parties fully inform borrowers about all closing costs, lender servicing and escrow account practices, and business relationships between closing service providers and other parties to the transaction.

REGULATORY MATTERS

In addition to the discussion contained herein regarding regulatory matters, refer to "General Regulation" in Item 1 of this Form 10-K for further discussion regarding the general regulatory framework.

PacifiCorp

Utah Mine Disposition

In December 2014, PacifiCorp filed applications with the UPSC, the OPUC, the WPSC and the 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 Plan 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, requested 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 Plan that was 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 included 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 requested 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 requested 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 serve to reduce the regulatory assets established as a result of the Utah Mine Disposition. The application requested continued recovery of contributions to the UMWA 1974 Pension Plan with ultimate ratemaking treatment of the UMWA 1974 Pension Plan withdrawal to be determined in a future proceeding once the final withdrawal obligation is determined.

In April 2015, PacifiCorp filed all-party settlement stipulations with the UPSC and the WPSC finding that the decision to enter into the Utah Mine Disposition transaction was prudent and in the public interest and recommended the appropriate treatment for accounting and ratemaking purposes. The UPSC approved the stipulation in April 2015 and the WPSC approved the stipulation in May 2015. The IPUC also issued an order in May 2015, approving the Utah Mine Disposition and ruling that the decision to enter into the transaction was prudent and in the public interest. The IPUC's order established the accounting treatment necessary to implement the transaction while deferring any incremental ratemaking treatment to the next general rate case.

PacifiCorp's application filed with the OPUC requested that the OPUC determine that closure of the Deer Creek mine was in the public interest, that its decision to enter into the Utah Mine Disposition was prudent and sought approval to sell certain Utah mine assets. PacifiCorp also requested 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 requested the same treatment of the UMWA 1974 Pension Plan withdrawal sought in the applications filed with the UPSC, the WPSC and the IPUC. In May 2015, the OPUC issued its final order concluding that the transaction produces net benefits for customers and was in the public interest. In accordance with the OPUC order, PacifiCorp implemented two tariffs that reflect an overall annual rate increase of $3 million effective June 2015.

In December 2014, PacifiCorp also filed an advice letter with the CPUC to request approval to sell certain Utah mining assets and to establish memorandum accounts to track the costs associated with the Utah Mine Disposition for future recovery. In July 2015, the CPUC Energy Division issued a letter requiring PacifiCorp to file a formal application for approval of the sale of certain Utah mining assets. Accordingly, in September 2015, PacifiCorp filed an application with the CPUC.

For additional information related to the accounting impacts associated with the Utah Mine Disposition, refer to Note 6 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K and Notes 5 and 9 of the Notes to Consolidated Financial Statements of PacifiCorp in Item 8 of this Form 10-K.

Utah

In March 2015, PacifiCorp filed its annual EBA with the UPSC requesting recovery of $31 million in deferred net power costs for the period January 1, 2014 through December 31, 2014. In September 2015, a settlement agreement was filed with the UPSC in which the parties agreed to recovery of $30 million. In October 2015, the UPSC approved the settlement agreement with the new rates effective November 2015.

In March 2015, PacifiCorp filed its annual REC balancing account application with the UPSC requesting recovery of $6 million over a two-year period. In May 2015, the UPSC approved the new rates effective June 2015 on an interim basis until a final order is issued by the UPSC. In September 2015, the UPSC issued a final order approving the interim rates as final.

Oregon

In April 2015, PacifiCorp made its initial filing for the annual TAM with the OPUC for an annual increase of $12 million, or an average price increase of 1%, based on forecasted net power costs for calendar year 2016. In October 2015, the OPUC issued a preliminary order approving PacifiCorp's request. PacifiCorp filed the final update reducing the requested increase to $9 million effective January 2016. A final order from the OPUC approving the revised increase was issued in December 2015.

Wyoming

In March 2015, PacifiCorp filed a general rate case with the WPSC requesting an annual increase of $32 million, or an average price increase of 5%, effective January 2016. The filing included a proposal to implement a modified ECAM to replace the current ECAM, which sunsets for new deferrals December 2015. In June 2015, PacifiCorp filed a net power cost update that reduced the requested increase to $30 million. In September 2015, PacifiCorp filed rebuttal testimony reducing the requested increase to $27 million, or an average price increase of 4%. Hearings were held in October and early November of 2015. In December 2015, the WPSC approved an overall increase of $16 million effective January 2016, and approved the continuation of the current ECAM with certain modifications that allow for the inclusion of chemical costs and start-up fuel costs. In addition, the WPSC ordered a $1 million credit to customers for benefits related to bonus tax depreciation through a separate tariff rider effective January 2016.

In March 2015, PacifiCorp filed its annual ECAM and RRA applications with the WPSC. The ECAM filing requests approval to recover $8 million in deferred net power costs for the period January 1, 2014 through December 31, 2014, and the RRA application requests approval to refund $1 million to customers. In May 2015, the WPSC approved the ECAM and RRA rates effective May 2015 on an interim basis. In September 2015, the WPSC approved a stipulation in which the parties agreed to allow the interim rates that were effective in May 2015 to become final.

Washington

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. In March 2015, the WUTC issued a final order in the proceeding approving an overall annual increase of $10 million, or an average price increase of 3%, effective March 2015. In April 2015, PacifiCorp filed a petition for judicial review of certain findings of the WUTC's March 2015 order.

In the March 2015 general rate case order described above, the WUTC initiated a second phase of the proceeding to implement a PCAM under which a portion of the difference between base net power costs set during a general rate case and actual net power costs would be deferred and reflected in future rates. In May 2015, the WUTC approved an all-party stipulation in which the parties agreed to the implementation of a PCAM. The PCAM applies a $4 million dead band for positive or negative net power cost variances. For net power cost variances between $4 million and $10 million, the PCAM reflects asymmetrical sharing bands in which amounts to be recovered from customers will be allocated 50% to customers and 50% to PacifiCorp, and amounts to be credited to customers will be allocated 75% to customers and 25% to PacifiCorp. Positive or negative net power cost variances in excess of $10 million will be allocated 90% to customers and 10% to PacifiCorp. PacifiCorp will make its first annual PCAM filing in June 2016 to cover net power costs for the period April 1, 2015 through December 31, 2015. The PCAM will convert to a calendar year basis beginning in 2016.

In November 2015, PacifiCorp submitted a filing with the WUTC for approval of an expedited rate filing, a two-year rate plan and a proposal for a decoupling mechanism. As part of the filing, PacifiCorp is seeking approval of a rate increase of $10 million, or an average price increase of 3%, effective mid-2016, and a second rate increase of $10 million, or an average price increase of 3%, effective mid-2017. The filing also includes a proposal to accelerate depreciation of certain coal-fueled generating facilities in the west control area that serve Washington. As part of the proposed rate plan, if approved, PacifiCorp commits to not file a general rate case for rates effective earlier than April 1, 2018. The WUTC decision is pending with a target effective date of the first step rate increase of July 1, 2016.

Idaho

In February 2015, PacifiCorp filed its annual ECAM application with the IPUC requesting recovery of $17 million, consisting primarily of $10 million for deferred net power costs and $6 million for the difference between REC revenues included in base rates and actual REC revenues. In March 2015, the IPUC approved recovery of $16 million effective April 2015.

In May 2015, PacifiCorp filed an application with the IPUC requesting approval to modify the ECAM, update base net power costs and increase rates by $10 million, effective January 2016. The requested increase included $7 million for the difference between REC revenues included in base rates and actual REC revenues, and $3 million as a result of updating base net power costs. In October 2015, PacifiCorp filed a settlement agreement with the IPUC in which the parties agreed to the requested increase in rates, effective January 2016. The IPUC approved the settlement agreement in December 2015. The settlement agreement modifies the ECAM to include production tax credits and exclude sulfur dioxide revenues. In addition, the settlement agreement allows another update to base net power costs in rates to be effective January 2017 and also specifies that January 2018 would be the earliest effective date that PacifiCorp could seek an increase to base rates through a general rate case.

In February 2016, PacifiCorp filed its annual ECAM application with the IPUC requesting recovery of $17 million, consisting primarily of $7 million for deferred net power costs, $6 million for the difference between REC revenues included in base rates and actual REC revenues and $4 million for a Lake Side 2 resource adder. If approved by the IPUC, the new rates will be effective April 2016.

California

In August 2014, PacifiCorp filed for a rate increase of $5 million, or 4%, through its annual ECAC. The CPUC approved the new rates effective March 2015.

In June 2015, PacifiCorp filed for a rate increase of $1 million, or 1%, through its PTAM for major capital additions to include the costs of the Sigurd-Red Butte transmission line in rates. The CPUC approved the new rates effective July 2015.

In August 2015, PacifiCorp filed for a rate decrease of $2 million, or 2%, through its annual ECAC. In December 2015, the CPUC approved the new rates effective January 2016.

In October 2015, PacifiCorp filed for a rate increase of $1 million, or 1%, through its PTAM for attrition factor. The CPUC approved PacifiCorp's filing in October 2015 with new rates effective January 2016.

MidAmerican Energy

In July 2014, the IUB issued an order approving new retail electric base rates for MidAmerican Energy's Iowa customers. The order allowed MidAmerican Energy to increase its base rates over approximately three years with equal annualized increases in revenues of $45 million, or 3.6% over 2012, effective August 2013 and again on January 1, 2015 and 2016, for a total annualized increase of $135 million when fully implemented. In addition to an increase in base rates, the order approved (1) the implementation of two new adjustment clauses related to the recovery of retail energy production costs and certain electric transmission charges (2) seasonal pricing that increased the difference between higher base rates in effect for June through September and base rates applicable to the remaining months of the year; and (3) a revenue sharing mechanism that shares with MidAmerican Energy's customers 80% of revenues related to equity returns above 11% and 100% of revenues related to equity returns above 14%, with the customer portion of any sharing reducing rate base. The changes in seasonal pricing, adjustment clauses and new revenue sharing mechanism were effective with final base rates. Additionally, MidAmerican Energy and the OCA have agreed not to seek or support an increase or decrease in the final base rates to become effective prior to January 1, 2018, unless MidAmerican Energy projects its return on equity for 2015, 2016 or 2017 to be below 10%.

NV Energy (Nevada Power and Sierra Pacific)

The PUCN's final order approving the merger between BHE and NV Energy stipulated that the Nevada Utilities would not seek recovery of any lost revenue for calendar year 2014 in an amount that exceeded 50% of the lost revenue the Nevada Utilities could otherwise request. In February 2014, the Nevada Utilities each filed an application with the PUCN to reset the EEIR and EEPR. In June 2014, the PUCN accepted a stipulation to adjust the EEIR, as of July 1, 2014, to collect 50% of the estimated lost revenue that the Nevada Utilities would otherwise be allowed to recover for the 2014 calendar year. The EEIR was effective from July through December 2014, reset on January 1, 2015 and was in effect through September 2015.

In February 2015, the Nevada Utilities each filed an application to reset the EEIR and EEPR. In August 2015, the PUCN accepted a stipulation for the Nevada Utilities to calculate the base EEIR using a revised methodology for calculating lost revenue and for Nevada Power and Sierra Pacific to make a $5 million and $1 million reduction, respectively, to the EEPR revenue requirement to more accurately reflect the actual level of spending and to minimize any over collection from its customers. The reset of the EEIR and EEPR was effective October 1, 2015 and remains in effect through September 30, 2016. To the extent the Nevada Utilities' earned rate of return exceeds the rate of return used to set base general rates, the Nevada Utilities' are required to refund to customers EEIR revenue collected. The current EEIR liability for Nevada Power and Sierra Pacific is $18 million and $3 million, respectively, which is included in current regulatory liabilities on each respective Consolidated Balance Sheet as of December 31, 2015.

In November 2014, one Nevada Power retail electric customer filed an application with the PUCN to purchase energy from a provider of a new electric resource and become a distribution only service customer. The application was denied in June 2015 and the customer subsequently filed a petition for reconsideration. In July 2015, the PUCN approved a settlement between the customer and Nevada Power. In October 2015, the PUCN approved a separate green energy agreement between Nevada Power and the customer and tariff changes embedded in the settlement agreement. The customer withdrew its petition for reconsideration in November 2015. In May 2015, three additional customers filed applications to purchase energy from a provider of a new electric resource and become a distribution only service customer. In December 2015, the PUCN granted the applications of the three customers subject to conditions, including paying an impact fee, on-going charges and receiving approval for specific alternative energy providers and terms.

In December 2015, the customers filed petitions for reconsideration. In January 2016, the PUCN granted reconsiderations and updated some of the terms, removing a limitation related to energy purchased indirectly from NV Energy. One of the applicants subsequently filed a petition for judicial review and a complaint for declaratory relief in state district court. In addition, there are no material applications pursuant to Chapter 704B pending before the PUCN in Nevada Power's and Sierra Pacific's respective service territories.

Net Metering

Nevada enacted Senate Bill 374 ("SB 374") on June 5, 2015. The legislation required the Nevada Utilities to prepare cost-of-service studies and propose new rules and rates for customers who install distributed, renewable generating resources. In July 2015, the Nevada Utilities made filings in compliance with SB 374 and the PUCN issued final orders December 23, 2015.

The final orders issued by the PUCN establish separate rate classes for customers who install distributed, renewable generating facilities. The establishment of separate rate classes recognizes the unique characteristics, costs and services received by these partial requirements customers. The PUCN also established new, cost-based rates or prices for these new customer classes, including increases in the basic service charge and related reductions in energy charges. Finally, the PUCN established a separate value for compensating customers who produce and deliver excess energy to the Nevada Utilities. The valuation will consider eleven factors, including alternatives available to the Nevada Utilities. The PUCN established a gradual, five-step process for transition over four years to the new, cost-based rates.

In January 2016, the PUCN denied requests to stay the order issued December 23, 2015. The PUCN also voted to reopen the evidentiary proceeding to address the application of new net metering rules for customers who applied for net metering service before the issuance of the final order. In February 2016, the PUCN affirmed most of the provisions of the December 23, 2015 order and adopted a twelve-year transition plan for changing rates for net metering customers to cost-based rates for utility services and value-based pricing for excess energy.

Emissions Reduction and Capacity Replacement Plan

In July 2015, Nevada Power filed an amendment to its Emissions Reduction and Capacity Replacement Plan ("ERCR Plan") with the PUCN. In September 2015, the PUCN approved the filed amendment requesting two renewable power purchase agreements with 100-MW solar photovoltaic generating facilities related to the replacement of coal plants. Each of these agreements were entered into by issuing requests for proposals for the procurement of energy through the competitive solicitation process that was set forth in Nevada Power's ERCR Plan in compliance with Senate Bill No. 123 ("SB 123"). In June 2015, the Nevada State Legislature passed Assembly Bill No. 498, which modified the capacity replacement components of SB 123. As a result, Nevada Power will not proceed with issuance of a third 100-MW request for proposal for renewable energy until such time as the PUCN determines Nevada Power has satisfactorily demonstrated a need for such electric generating capacity.

Joint Dispatch Agreement Application

The Nevada Utilities were parties to an Interim Joint Dispatch Agreement ("Interim JDA") which outlined the joint dispatch of their combined power supply resources utilizing ON Line. In March 2015, the Nevada Utilities filed an application with the PUCN seeking approval of a Joint Dispatch Agreement with a new term (the "JDA"). In July 2015, the PUCN approved the JDA with minor modifications, and established December 31, 2019 as the termination date for the agreement. The JDA became effective September 29, 2015, by approval from the FERC, replacing the Interim JDA. The JDA covers real-time, hourly and daily transactions, including sales of the combined resources into the California ISO through the EIM.

The primary difference between the Interim JDA and the JDA is the extension of the agreement to December 31, 2019, at which time the Nevada Utilities and their regulators will review the JDA to determine if it should be renewed or amended. The JDA also recognizes that, upon NV Energy's entry into the EIM, dispatch and non-native sales include transactions with the California ISO. As with the prior versions of the JDA, the agreement establishes Nevada Power as the EIM scheduling coordinator for both Sierra Pacific and Nevada Power and recognizes that the joint dispatch costs and benefits associated with the EIM transactions will be governed by the accounting protocols and allocations set forth in the JDA.

Advanced Metering Infrastructure

In October 2014, the PUCN issued an order directing the Nevada Utilities to provide information relating to failures in certain remote disconnect/reconnect electric meters the Nevada Utilities have installed after media reports were published that electric meter failures may have resulted in fire events. The Nevada Utilities completed an internal review in response to this and other federal, state and local inquiries relating to these events. The information compiled and submitted indicates that no fire has resulted from the remote disconnect/reconnect electric meters. Additionally, in October 2014, the Nevada State Fire Marshal issued a report concluding that the incidents of electric arcing fires continue to decrease in Nevada and at this time there is no statewide fire problem related to the replacement of electric meters. In December 2014, the Nevada Utilities filed the requested information with the PUCN. In March 2015, the PUCN staff made additional requests and in May 2015, the Nevada Utilities provided the follow up items. In September 2015, the Nevada Utilities provided the PUCN electric meter testing results from a third party laboratory. All tests of the integrity and functionality of the meters subject to the distress testing passed. Analysis and internal investigation is continuing, but Nevada Power and Sierra Pacific do not believe this will have a material adverse impact on each respective Consolidated Financial Statements.

ALP

General Tariff Applications

In November 2014, ALP filed a general tariff application ("GTA") asking the AUC to approve revenue requirements of C $811 million for 2015 and C$1.0 billion for 2016, primarily due to continued investment in capital projects as directed by the AESO.

In June 2015, ALP amended the GTA to propose additional transmission tariff relief measures for customers and modifications to its capital structure. The amended GTA includes timing benefits to customers by discontinuing (i) the use of construction work-in-progress in-rate base effective January 1, 2015, and refunding related amounts received as part of the 2011 to 2014 transmission tariffs and (ii) the collection in advance of future income taxes, effective January 1, 2016, and refunding amounts previously received as part of the transmission tariffs.

In October 2015, an update to this amended application was filed. The October 2015 update requested the AUC to approve an increase to 39% in ALP's common equity ratio resulting in revenue requirements of C$672 million for 2015 and C$703 million for 2016. In addition, the October 2015 update forecasted capital expenditures to be C$961 million for 2015 and C$538 million for 2016. ALP based its direct assign capital forecast, which comprises more than 80% of its total capital expenditures, on the long-range capital plan released by the AESO in January 2014, using its risk-adjusted capital forecasting model accepted by the AUC in its decision on ALP's previous general tariff application. ALP's actual capital program may vary from ALP's regulatory filings, depending on the timing of regulatory approvals, directions from the AESO, and other factors beyond ALP's control.

The oral hearing for the 2015-2016 GTA, which was amended and updated, took place December 2015 and the AUC is expected to issue its final decision in the second quarter of 2016. In addition, the AUC approved ALP's request to continue its 2015 interim transmission tariff decision to invoice the AESO C$61 million per month commencing January 1, 2016, until a final decision is issued for the 2015-2016 GTA.

In February 2016, ALP filed a GTA asking the AUC to approve its transmission tariff of C$853 million for 2017 and C$990 million for 2018.

2016 Generic Cost of Capital Proceeding

In April 2015, the AUC opened a new GCOC proceeding to set the deemed capital structure and generic returns for 2016 and 2017. The AUC has issued a schedule for this proceeding with a hearing scheduled for the second quarter of 2016. ALP filed evidence in January 2016. ALP's external rate of return expert evidence proposes 9% to 10.5% return on equity, on a recommended equity component of 40%, compared to the placeholder return on equity of 8.3% on a 36% equity component. The fair return and equity thickness recommended reflect the concerns noted by rating agencies and other members of the financial community regarding the increased business risks of utilities in Alberta. ALP's credit metrics expert has recommended that the AUC authorize return on equity and equity thickness determinations that allow for a funds from operations to debt credit ratio above the 13% that Standard & Poor's has cautioned might be a floor for regulated utilities facing growing uncertainty while operating in Alberta. ALP also filed evidence which outlined capital market participant's heightened view of the Alberta utility regulatory environment and the widening credit spreads.

Deferral Account Reconciliation Application

In December 2014, ALP filed its 2012-2013 Deferral Accounts Reconciliation Application seeking the AUC's approval to collect C$30 million from the AESO for previously uncollected deferral account balances. In addition, ALP is seeking approval of nearly C$1.7 billion of direct assign capital additions, included as part of the direct assigned capital deferral account filing. The oral hearing took place in November 2015 and reconvened in January 2016 because there was not sufficient time to complete the hearing. A decision from the AUC is expected in mid-2016.

Appeals of Recent AUC *Decisions*

In March 2015, the AUC issued its decision regarding cost of capital matters applicable to all electricity and natural gas utilities under its jurisdiction, including ALP. In its decision, which was retroactively applied to January 1, 2013, the AUC decreased the generic rate of return on common equity applicable to all utilities to 8.30% from the previously approved placeholder rate of 8.75% and decreased ALP's common equity ratio from 37% to 36% for the years 2013, 2014 and 2015. The approved common equity ratio and generic rate of return on common equity will remain in effect on an interim basis for 2016 and beyond, until changed by the AUC. ALP and other utilities had applied to the Alberta Court of Appeal for Leave to appeal this decision, which is set to be heard in May 2016.

In November 2013, the AUC issued its Utility Asset Disposition ("UAD") decision in which it concluded, among other things, that in the case of the extraordinary retirement of an asset before it is fully depreciated, under or over recovery of capital investment on an extraordinary retirement should be borne by the utility and its shareholders. ALP and other utilities appealed the AUC's UAD decision to the Alberta Court of Appeal, which was dismissed in September 2015. In November 2015, ALP, Epcor and Enmax, filed a joint leave application to the Supreme Court of Canada for appeal of the Alberta Court of Appeal's UAD decision.

In its November 2013 decision pertaining to ALP's 2013-2014 GTA, the AUC directed ALP to re-forecast the capital project expenditures for 2013 and 2014 Engineering, Procurement and Construction Management ("EPCM") services to reflect a two times labor multiplier and other approved mark-ups. While the AUC has not disallowed the new EPCM rates that ALP negotiated, there is a risk that, in a future direct assigned capital deferral account decision, the AUC may disallow a portion of the costs ALP has incurred for EPCM services in connection with capital projects executed under these relationship agreements. ALP has appealed this decision, which is scheduled to be heard in February 2016. ALP has requested approval of the capital project expenditures, including the new competitively bid EPCM rates, in its 2012-2013 direct assigned capital deferral account filing. ALP filed additional evidence supporting the new EPCM rates in 2015.

BHE U.S. Transmission

A significant portion of ETT's revenues are based on interim rate changes that can be filed twice annually and are subject to review and possible true-up in the next filed base rate proceeding. In July 2015, the most recent interim filing was approved which set total annual revenue requirements at $304 million and a rate base of $2.2 billion. In November 2015, the PUCT ordered ETT to file a base rate case by February 2017. Results of a base rate review would be prospective except for any deemed disallowance by the PUCT of the transmission investment since the initial base rate case in 2007. A refund of interim transmission rates would reduce future net income and cash flows. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

Northern Powergrid Distribution Companies

In March 2015, Northern Powergrid sought permission from the Competition and Markets Authority ("CMA") to appeal against the license modifications that give effect to the RIIO-ED1 price control. The appeal related to three specific areas:

- Ofgem's decision to demand further cost savings in relation to smart grid technology over and above the ones captured by its original benchmarking exercise;
- Ofgem's assessment of the variation in wage rates across the country; and
- Ofgem's projections for labor cost increases.

Permission to appeal was granted by the CMA on March 30, 2015. British Gas Trading Limited (an electricity supplier) was granted permission to appeal the price control, with a view to reduce the revenue available to all slow-tracked Distribution Network Operators.

In September 2015, the CMA announced that it had upheld Northern Powergrid's appeal on cost savings in relation to smart grid technology concluding that Ofgem's decision was not based on robust evidence. The CMA has therefore increased Northern Powergrid's cost allowance for the period to March 2023 by £32 million (2012/13 prices). The CMA decided that Ofgem's decision on the assessment of the variation in wage rates across the country and their projections for labor cost increases fell within the margin of discretion that is available to Ofgem.

In September 2015, the CMA also announced that it had upheld one part of one ground of the British Gas appeal. As a result the CMA has reduced the value of an incentive scheme for all slow-tracked Distribution Network Operators which reduces Northern Powergrid revenues by £14 million (2012/13 prices) over the period to March 2023.

ENVIRONMENTAL LAWS AND REGULATIONS

Each Registrant is subject to federal, state, local and foreign 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 each Registrant'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, local and international agencies. Each Registrant believes it is in material compliance with all applicable laws and regulations, although many laws and regulations are subject to interpretation that may ultimately be resolved by the courts. Refer to "Liquidity and Capital Resources" of each respective Registrant in Item 7 of this Form 10-K for discussion of each Registrant's forecast environmental-related capital expenditures.

Clean Air Act Regulations

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

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. In October 2015, the EPA set the standard at 70 parts per billion. The EPA anticipates making attainment/nonattainment designations for the revised standards by late 2017, which will likely be based on 2014-2016 air quality data. Nonattainment areas will have until 2020 to late 2037 to meet the standard. Given the level at which the standard was set in conjunction with retirements and the installation of controls, the new standard is not expected to have a significant impact on the relevant Registrant.

Until the 2015 standard is fully implemented, the EPA continues to implement 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 December 2012, the EPA approved Nevada's request to redesignate Clark County to be in attainment for the 1997 eight-hour ozone standard while also approving Clark County's plan to maintain compliance with the standard through 2022. However, Clark County remains unclassifiable for the 2008 ozone standard. If the EPA revises the ozone standard to be more stringent, it is possible that Clark County will again be designated as nonattainment for ozone, creating the potential to impact Nevada Power's Clark, Sun Peak, Las Vegas, Lenzie, Silverhawk, Harry Allen, Higgins, and Goodsprings generating facilities. However, until such time as the 2015 standard is implemented or Clark County is classified as nonattainment for the 2008 or 2015 standards, potential impacts cannot be determined.

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 and determined, at that date, that a portion of Muscatine County, Iowa was in nonattainment for the one-hour sulfur dioxide standard. MidAmerican Energy's Louisa coal-fueled generating facility is located just outside of Muscatine County, south of the violating monitor. In its final designation, the EPA indicated that it was not yet prepared to conclude that the emissions from the Louisa coal-fueled generating facility contribute to the monitored violation or to other possible violations, and that in a subsequent round of designations, the EPA will make decisions for areas and sources outside Muscatine County. MidAmerican Energy does not believe a subsequent nonattainment designation will have a material impact on the Louisa coal-fueled generating facility. Although the EPA's July 2013 designations did not impact PacifiCorp's nor the Nevada Utilities' 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.

The Sierra Club filed a lawsuit against the EPA in August 2013 with respect to the one-hour sulfur dioxide standards and its failure to make certain attainment designations in a timely manner. In March 2015, the United States District Court for the Northern District of California ("Northern District of California") accepted as an enforceable order an agreement between the EPA and Sierra Club to resolve litigation concerning the deadline for completing the designations. The Northern District of California's order directed the EPA to complete designations in three phases: the first phase by July 2, 2016; the second phase by December 31, 2017; and the final phase by December 31, 2020. The first phase of the designations require the EPA to designate two groups of areas: 1) areas that have newly monitored violations of the 2010 sulfur dioxide standard; and 2) areas that contain any stationary source that, according to the EPA's data, either emitted more than 16,000 tons of sulfur dioxide in 2012 or emitted more than 2,600 tons of sulfur dioxide and had an emission rate of at least 0.45 lbs/sulfur dioxide per million British thermal unit in 2012 and, as of March 2, 2015, had not been announced for retirement. MidAmerican Energy's George Neal Unit 4 and the Ottumwa Generating Station (in which MidAmerican Energy has a majority ownership interest, but does not operate), are included as units subject to the first phase of the designations, having emitted more than 2,600 tons of sulfur dioxide and having an emission rate of at least 0.45 lbs/sulfur dioxide per million British thermal unit in 2012. States may submit to the EPA updated recommendations and supporting information for the EPA to consider in making its determinations. Iowa has assembled technical support documents demonstrating that all facilities affected by the first phase of designations have attained the standard, but has not yet submitted the information to the EPA. The EPA intends to promulgate final sulfur dioxide area designations no later than July 2, 2016.

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 the relevant Registrant operates generating facilities have been classified as "unclassifiable/attainment." Unless additional monitoring suggests otherwise, the relevant Registrant does not anticipate that any impacts of the revised standard will be significant.

In December 2014, the Utah SIP for fine particulate matter was adopted by the Utah Air Quality Board. PacifiCorp's Lake Side and Gadsby generating facilities operate within nonattainment areas for fine particulate matter; however, the SIP 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 its consolidated financial results.

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 the Registrants 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 MATS became effective on April 16, 2012, and required that new and existing coal-fueled generating facilities achieve emission standards for mercury, acid gases and other non-mercury hazardous air pollutants. Existing sources were required to comply with the new standards by April 16, 2015 with the potential for individual sources to obtain an extension of 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. The relevant Registrants have completed emission reduction projects to comply with the final rule's standards for acid gases and non-mercury metallic hazardous air pollutants.

MidAmerican Energy is retiring certain coal-fueled generating units as the least-cost alternative to comply with the MATS. Walter Scott, Jr. Energy Center Units 1 and 2 were retired in 2015, and George Neal Energy Center Units 1 and 2 are to be retired by April 15, 2016. A fifth unit, Riverside Generating Station, was limited to natural gas combustion in March 2015.

PacifiCorp retired its two coal-fueled generating units at the Carbon Facility in 2015 to comply with the MATS requirements and other environmental regulations as well as in conformance with Utah's Regional Haze SIP. Refer to the Regional Haze section below for additional requirements regarding the Carbon Facility.

Numerous lawsuits have been filed in the 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. Oral argument in the case was held before the United States Supreme Court in March 2015, and a decision was issued by the United States Supreme Court in June 2015, which reversed and remanded the MATS rule to the D.C. Circuit for further action. The United States Supreme Court held that the EPA had acted unreasonably when it deemed cost irrelevant to the decision to regulate generating facilities, and that cost, including costs of compliance, must be considered before deciding whether regulation is necessary and appropriate. The United States Supreme Court's decision did not vacate or stay implementation of the MATS rule. In December 2015, the D.C. Circuit issued an order remanding the rule to the EPA, without vacating the rule. As a result, the relevant Registrants continue to have a legal obligation under the MATS rule and the respective permits issued by the states in which each respective Registrant operates to comply with the MATS rule, including operating all emissions controls or otherwise complying with the MATS requirements.

Cross-State Air Pollution Rule

The EPA promulgated an initial rule in March 2005 to reduce emissions of nitrogen oxides and sulfur dioxide, precursors of ozone and particulate matter, from down-wind sources in the eastern United States, including Iowa, to reduce emissions by implementing a plan based on a market-based cap-and-trade system, emissions reductions, or both. After numerous appeals, the Cross-State Air Pollution Rule ("CSAPR") was promulgated to address interstate transport of sulfur dioxide and nitrogen oxides emissions in 27 eastern and Midwestern states.

The first phase of the rule was implemented January 1, 2015. In November 2015, the EPA released a proposed rule that would further reduce nitrogen oxides emissions in 2017. The public comment period closed on the proposal February 1, 2016.

MidAmerican Energy has installed emissions controls at some of its coal-fueled generating facilities to comply with the CSAPR and may purchase emissions allowances to meet a portion of its compliance obligations. The cost of these allowances is subject to market conditions at the time of purchase and historically has not been material. MidAmerican Energy believes that the controls installed to date are consistent with the reductions to be achieved from implementation of the rule; however, the rule's full impact cannot be predicted until the EPA takes final action on the Phase II rules.

MidAmerican Energy operates natural gas-fueled generating facilities in Iowa and BHE Renewables operates natural gas-fueled generating facilities in Texas, Illinois and New York, which are subject to the CSAPR. However, the provisions are not anticipated to have a material impact on Berkshire Hathaway Energy or MidAmerican Energy. None of PacifiCorp's, Nevada Power's or Sierra Pacific's generating facilities are subject to the CSAPR.

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, Arizona and Colorado and certain of Nevada Power's and Sierra Pacific's fossil-fueled generating facilities 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. 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 completed an alternative BART analysis for Hunter Units 1 and 2, and Huntington Units 1 and 2. The alternative BART analysis and revised regional haze SIP were submitted in June 2015 to the EPA for review and proposed action after a public comment period. The revised regional haze SIP included a state-enforceable requirement to cease operation of the Carbon Facility by August 15, 2015. PacifiCorp retired the Carbon Facility in December 2015. In January 2016, the EPA published two alternative proposals to either approve the Utah SIP as written or reject the Utah SIP relating to nitrogen oxides controls and require the installation of selective catalytic reduction ("SCR") controls at Hunter Units 1 and 2 and Huntington Units 1 and 2 within five years. In January 2016, a public hearing was held on the EPA's alternative proposals and the public comment period closes March 14, 2016. The EPA's final action on the Utah regional haze SIP is expected in mid-2016. Until the EPA makes its final determination, it is unknown whether additional controls will be required on the four BART-eligible units in Utah.

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 and the EPA's approval was upheld on appeal by the Tenth Circuit in October 2014. 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 also filed an appeal of the EPA's final action, as did 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 allowing Naughton Unit 3 to operate on coal through 2017 and providing for natural gas conversion of the unit in 2018. In its final action, the EPA indicated it supported the conversion of the unit to natural gas as its fuel source and would expedite action relative to consideration of the natural gas conversion once the state of Wyoming submitted the requisite SIP amendment; nonetheless, Naughton Unit 3 natural gas conversion, should it ultimately be pursued, 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 in February 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, permit applications and studies were submitted to amend the Cholla Title V permit, and subsequently the Arizona SIP to convert Cholla Unit 4 to a natural gas-fueled unit in 2025. The Arizona Department of Environmental Quality prepared a draft permit and a revision to the Arizona regional haze SIP, held two public hearings in July 2015 and, after considering the comments received during the public comment period that closed on July 14, 2015, submitted the final proposals to the EPA for review, public comment and final action. The EPA's final action on the Arizona regional haze SIP is expected by late 2016.

The state of Colorado regional haze SIP 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. In addition, in February 2015, the state of Colorado submitted an amendment to its regional haze SIP relating to Craig Unit 1, in which PacifiCorp has an ownership interest, to require the installation of SCR controls by 2021. The amended SIP is pending consideration by the EPA.

The Navajo Generating Station, in which Nevada Power is a joint owner with an 11.3% ownership share, is also a source that is subject to the regional haze BART requirements. In January 2013, the EPA announced a proposed FIP addressing BART and an alternative for the Navajo Generating Station that includes a flexible timeline for reducing nitrogen oxides emissions. Nevada Power, along with the other owners of the facility, have been reviewing the EPA's proposal to determine its impact on the viability of the facility's future operations. The land lease for the Navajo Generating Station is subject to renewal in 2019. Renewal of the lease will require completion of an Environmental Impact Statement as well as a renewal of the fuel supply agreement. In September 2013, the EPA issued a supplemental proposal that included another BART alternative called the Technical Work Group Alternative, which is based on a proposal submitted to the EPA by a group of Navajo Generating Station stakeholders. The EPA accepted comments on the various alternatives through January 6, 2014 and, in August 2014, the EPA announced it had approved the final plan for the Navajo Generating Station, including the reduction of emissions of nitrogen oxides by approximately 80% through the retirement of one unit, or the curtailment of generation equivalent to one unit, in 2019 and installation of SCR controls at the other two units by 2030. In October 2014, several groups filed an appeal of the EPA's decision in the Ninth Circuit. The Hopi Tribe was initially part of the larger group appeal but their challenge was subsequently severed from that appeal and is proceeding separately. Until such time as additional action is taken by the Ninth Circuit and the uncertainties regarding lease and agreement renewal terms for the Navajo Generating Station are addressed, Nevada Power cannot predict the outcome of this matter. Nevada Power filed the ERCR Plan in May 2014 that proposed to eliminate its ownership participation in the Navajo Generating Station in 2019, which was approved by the PUCN.

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

Climate Change

In December 2015, an international agreement was negotiated by 195 nations to create a universal framework for coordinated action on climate change in what is referred to as the Paris Agreement. The Paris Agreement reaffirms the goal of limiting global temperature increase well below 2 degrees Celsius, while urging efforts to limit the increase to 1.5 degrees Celsius; establishes commitments by all parties to make nationally determined contributions and pursue domestic measures aimed at achieving the commitments; commits all countries to submit emissions inventories and report regularly on their emissions and progress made in implementing and achieving their nationally determined commitments; and commits all countries to submit new commitments every five years, with the expectation that the commitments will get more aggressive. In the context of the Paris Agreement, the United States agreed to reduce greenhouse gas emissions 26% to 28% by 2025 from 2005 levels. The cornerstone of the United States' commitment is the Clean Power Plan which was finalized by the EPA in 2015.

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. On August 3, 2015, the EPA issued final new source performance standards, establishing a standard of 1,000 pounds of carbon dioxide per MWh for large natural gas-fueled generating facilities and 1,400 pounds of carbon dioxide per MWh for new coal-fueled generating facilities with the "Best System of Emission Reduction" reflecting highly efficient supercritical pulverized coal facilities with partial carbon capture and sequestration or integrated gasification combined-cycle units that are co-fired with natural gas or pre-combustion slipstream capture of carbon dioxide. The new source performance standards have been appealed to the D.C. Circuit Court of Appeals. However, despite the pendency of the appeal, any new fossil-fueled generating facilities constructed by the relevant Registrants will be required to meet the GHG new source performance standards.

Clean Power Plan

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 the "Best System of Emission Reduction." In August 2015, the final Clean Power Plan was released, which established the Best System of Emission Reduction as including: (a) heat rate improvements; (b) increased utilization of existing combined-cycle natural gas-fueled generating facilities; and (c) increased deployment of new and incremental non-carbon generation placed in-service after 2012. The EPA also changed the compliance period to begin in 2022, with three interim periods of compliance and with the final goal to be achieved by 2030. Based on changes to the state emission reduction targets, which are now all between 771 pounds per MWh and 1,305 pounds per MWh, the Clean Power Plan, when fully implemented, is expected to reduce carbon dioxide emissions in the power sector to 32% below 2005 levels by 2030. The EPA also released in August 2015, a draft federal plan as an option or backstop for states to utilize in the event they do not submit approvable state plans. The public comment period on the draft federal plan and proposed model trading rules closed January 21, 2016. States were required to submit their initial implementation plans by September 2016 but could request an extension to September 2018. However, on February 9, 2016, the United States Supreme Court ordered that the EPA's emission guidelines for existing sources be stayed pending the disposition of the challenges to the rule in the D.C. Circuit Court of Appeals and any action on a writ of certiorari before the United States Supreme Court. The full impacts of the final rule or the federal plan on the Registrants cannot be determined until the outcome of the pending litigation and subsequent appeals, the development and implementation of state plans, and finalization of the federal plan. PacifiCorp, MidAmerican Energy, Nevada Power and Sierra Pacific have historically pursued cost-effective projects, including plant efficiency improvements, increased diversification of their generating fleets to include deployment of renewable and lower carbon generating resources, and advancement of customer energy efficiency programs.

In the absence of comprehensive climate legislation or regulation, the Registrants have continued to invest in lower- and non-carbon generating resources and to operate in an environmentally responsible manner. In July 2015, BHE signed the American Business Act on Climate pledge, in which BHE pledged to build on the Company's combined investment of more than $15 billion in renewable energy generation under construction and in operation through 2014 by investing up to an additional $15 billion. Components of BHE's pledge include:

- Pursue the construction of an additional 552 MW of new wind-powered generation in Iowa, increasing MidAmerican Energy's generating portfolio to more than 4,000 MW of wind, which is equivalent to 58 percent of its retail energy load in 2017. MidAmerican Energy owns the largest portfolio of wind-powered generating capacity in the United States among rate-regulated utilities.
- Retire more than 75 percent of the Nevada Utilities' coal-fueled generating capacity in Nevada by 2019.
- Add more than 1,000 MW of incremental solar and wind capacity through long-term power purchase agreements to PacifiCorp's owned 1,030 MW of wind-powered generating capacity. PacifiCorp owns the second largest portfolio of wind-powered generating capacity in the United States among rate-regulated utilities. This incremental renewable generation, expected to be on-line by the end of 2017, would bring PacifiCorp's non-carbon generating capacity to more than 4,500 MW, which equates to approximately 22 percent of PacifiCorp's retail energy load in 2017.
- Invest in transmission infrastructure in the West and Midwest to support the integration of renewable energy onto the grid.
- Support and advance the development of markets in the West to optimize the electric grid, lower costs, enhance reliability and more effectively integrate renewable sources.

New federal, regional, state and international accords, legislation, regulation, or judicial proceedings limiting GHG emissions could have a material adverse impact on the Registrants, 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 the Registrants 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
- The relevant Registrant's natural gas pipeline operations, 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 the Registrants' 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 the relevant Registrant, and include:

- In June 2013, Nevada Senate Bill 123 ("SB 123") was signed into law. Among other things, SB 123 and regulations thereunder require Nevada Power to file with the PUCN an emission reduction and capacity replacement plan by May 1, 2014. In May 2014, Nevada Power filed its emissions reduction capacity replacement plan. The plan provided for the retirement or elimination of 300 MW of coal generating capacity by December 31, 2014, another 250 MW of coal generating capacity by December 31, 2017, and another 250 MW of coal generating capacity by December 31, 2019, along with replacement of such capacity with a mixture of constructed, acquired or contracted renewable and non-technology specific generating units. The plan also sets forth the expected timeline and costs associated with decommissioning coal-fired generating units that will be retired or eliminated pursuant to the plan. The PUCN has the authority to approve or modify the emission reduction and capacity replacement plan filed by Nevada Power. Given the PUCN may recommend and/or approve variations to Nevada Power's resource plans relative to requirements under SB 123, the specific impacts of SB 123 on Nevada Power cannot be determined.
- 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. An executive order issued in 2015 aims to reduce emissions to 40% below 1990 levels by 2030 and 80% by 2050.
- 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.
- In January 2016, the Washington State Department of Ecology proposed a new rule regulating greenhouse gas emissions from sources in Washington. The proposed rule would regulate greenhouse gases including carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride beginning in 2017 with three-year compliance periods thereafter (i.e., 2017-2019, 2020-2022, etc.). Under the proposed rule, the Washington State Department of Ecology will establish a greenhouse gas emissions reduction pathway for all covered entities. Covered entities may use emission reduction units, which may be traded with other covered entities, to meet their compliance requirements. PacifiCorp's resources that would be covered under the proposed rule would include the Chehalis generating facility, which is a natural gas combined-cycle plant located in Washington state.
- The Regional Greenhouse Gas Initiative, a mandatory, market-based effort to reduce GHG emissions in ten Northeastern and Mid-Atlantic states, required, beginning in 2009, the reduction of carbon dioxide emissions from the power sector of 10% by 2018. In May 2011, New Jersey withdrew from participation in the Regional Greenhouse Gas Initiative. Following a program review in 2012, the nine Regional Greenhouse Gas Initiative states implemented a new 2014 cap which was approximately 45% lower than the 2012-2013 cap. The cap is reduced each year thereafter by 2.5%.

GHG Litigation

Each Registrant closely monitors ongoing environmental litigation applicable to its respective operations. 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 the Registrants' generating facilities.

The GHG rules and the Registrants' compliance requirements are subject to potential outcomes from proceedings and litigation challenging the rules.

Renewable Portfolio Standards

Each state's RPS described below could significantly impact the relevant Registrant'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 the relevant Registrant can be subject to penalties in the event of noncompliance. Each Registrant 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 required 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. In October 2015, California Senate Bill No. 350 was signed into law, which increased the current RPS requirement to 40% by December 31, 2024, 45% by December 31, 2027 and 50% by December 31, 2030. 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.

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 within the WECC, and renewable energy credits can be used.

Since 1997, NV Energy has been required to comply with a RPS. Current law requires the Nevada Utilities to meet 18% of their energy requirements with renewable resources for 2014, 20% for 2015 through 2019, 22% for 2020 and 2024, and 25% for 2025 and thereafter. The RPS also requires 5% of the portfolio requirement come from solar resources through 2015 and increasing to 6% in 2016. Nevada law also permits energy efficiency measures to be used to satisfy a portion of the RPS through 2025, subject to certain limitations.

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 and MidAmerican Energy are assessing the options for compliance at their generating facilities impacted by the final rule and will complete impingement and entrainment studies. PacifiCorp's Dave Johnston generating facility and all of MidAmerican Energy's coal-fueled generating facilities, except Louisa, Ottumwa and Walter Scott, Jr. Unit 4, which have water cooling towers, withdraw 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 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 or MidAmerican Energy's existing intake structures require modification, the costs are not anticipated to be significant to the consolidated financial statements. Nevada Power and Sierra Pacific do not utilize once-through cooling water intake or discharge structures at any of their generating facilities. All of the Nevada Power and Sierra Pacific generating stations are designed to have either minimal or zero discharge; therefore, they are not impacted by the §316(b) final rule.

In November 2015, the EPA published final effluent limitation guidelines and standards for the steam electric power generating sector which, among other things, regulate the discharge of bottom ash transport water, fly ash transport water, combustion residual leachate and non-chemical metal cleaning wastes. 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 has changed the effluent discharged from coal- and natural gas-fueled generating facilities. Permitting authorities are required to include the new limits in each impacted facility's discharge permit upon renewal; the new limits must be met as soon as possible, beginning November 1, 2018 and must be implemented by December 31, 2023. Most of the issues raised by this rule are already being addressed through the coal combustion residuals rule and are not expected to impose significant additional requirements on the 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. The final rule was released in May 2015 but is currently under appeal in multiple courts and a nationwide stay on the implementation of the rule was issued in October 2015. Depending on the outcome of the appeal(s), 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. However, until the rule is fully litigated and finalized, the Registrants 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 RCRA. The public comment period closed in November 2010. The final rule was released by the EPA on December 19, 2014, was published in the Federal Register on April 17, 2015 and was effective on October 19, 2015. 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.

At the time the rule was published in April 2015, PacifiCorp operated 18 surface impoundments and seven landfills that contained coal combustion byproducts. Prior to the effective date in October 2015, nine surface impoundments and three landfills were either closed or repurposed to no longer receive coal combustion byproducts and hence are not subject to the final rule. MidAmerican Energy owns or operates nine surface impoundments and four landfills that contain coal combustion byproducts. At the time the rule was published in April 2015, the Nevada Utilities operated ten evaporative surface impoundments and two landfills that contained coal combustion byproducts. Prior to the effective date in October 2015, four of the surface impoundments were closed, four impoundments discontinued receipt of coal combustion byproducts and are subject to final closure on or before April 2018, and two surface impoundments remain active and subject to the final rule. The two landfills remain active and subject to the final rule. Refer to Note 13 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K and Note 10 of the Notes to Consolidated Financial Statements of PacifiCorp in Item 8 of this Form 10-K for discussion of the impacts on asset retirement obligations as a result of the final rule.

Other

Other laws, regulations and agencies to which the relevant Registrants are 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 Nuclear Waste Policy Act of 1982, under which the United States Department of Energy is responsible for the selection and development of repositories for, and the permanent disposal of, spent nuclear fuel and high-level radioactive wastes. Refer to Note 13 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K and Note 11 of the Notes to Financial Statements of MidAmerican Energy in Item 8 of this Form 10-K for additional information regarding MidAmerican Energy's nuclear decommissioning obligations.
- 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 PacifiCorp's 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 16 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K and Note 13 of the Notes to Consolidated Financial Statements of PacifiCorp in Item 8 of this Form 10-K for information regarding the relicensing of PacifiCorp's Klamath River hydroelectric system.

The Registrants expect they will be allowed to recover their respective prudently incurred costs to comply with the environmental laws and regulations discussed above. The Registrants' 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 the Registrants 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, the Registrants have 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.

Item 1A. Risk Factors

Each Registrant is 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 the relevant Registrant, should be made before making an investment decision. Additional risks and uncertainties not presently known or which each Registrant currently deems immaterial may also impair its business operations. Unless stated otherwise, the risks described below generally relate to each Registrant.

Corporate and Financial Structure Risks

BHE is a holding company and depends on distributions from subsidiaries, including joint ventures, to meet its obligations.

BHE is a holding company with no material assets other than the ownership interests in its subsidiaries and joint ventures, collectively referred to as its subsidiaries. Accordingly, cash flows and the ability to meet BHE's obligations are largely dependent upon the earnings of its subsidiaries and the payment of such earnings to BHE in the form of dividends or other distributions. BHE's subsidiaries are separate and distinct legal entities and have no obligation, contingent or otherwise, to pay amounts due pursuant to BHE's senior debt, junior subordinated debt or its other obligations, or to make funds available, whether by dividends or other payments, for the payment of amounts due pursuant to BHE's senior debt, junior subordinated debt or its other obligations, and do not guarantee the payment of any of its obligations. Distributions from subsidiaries may also be limited by:

- their respective earnings, capital requirements, and required debt and preferred stock payments;
- the satisfaction of certain terms contained in financing, ring-fencing or organizational documents; and
- regulatory restrictions that limit the ability of BHE's regulated utility subsidiaries to distribute profits.

BHE is substantially leveraged, the terms of its existing senior and junior subordinated debt do not restrict the incurrence of additional debt by BHE or its subsidiaries, and BHE's senior debt is structurally subordinated to the debt of its subsidiaries, and each of such factors could adversely affect BHE's consolidated financial results.

A significant portion of BHE's capital structure is comprised of debt, and BHE expects to incur additional debt in the future to fund items such as, among others, acquisitions, capital investments and the development and construction of new or expanded facilities. As of December 31, 2015, BHE had the following outstanding obligations:

- senior unsecured debt of $7.8 billion;
- junior subordinated debentures of $2.9 billion;
- borrowings under its commercial paper program of $253 million;
- guarantees and letters of credit in respect of subsidiary and equity method investments aggregating $234 million; and
- commitments, subject to satisfaction of certain specified conditions, to provide equity contributions in support of renewable tax equity investments totaling $478 million.

BHE's consolidated subsidiaries also have significant amounts of outstanding debt, which totaled $27.9 billion as of December 31, 2015. These amounts exclude (a) trade debt, (b) preferred stock obligations, (c) letters of credit in respect of subsidiary debt, and (d) BHE's share of the outstanding debt of its own or its subsidiaries' equity method investments.

Given BHE's substantial leverage, it may not have sufficient cash to service its debt, which could limit its ability to finance future acquisitions, develop and construct additional projects, or operate successfully under difficult conditions, including those brought on by adverse national and global economies, unfavorable financial markets or growth conditions where its capital needs may exceed its ability to fund them. BHE's leverage could also impair its credit quality or the credit quality of its subsidiaries, making it more difficult to finance operations or issue future debt on favorable terms, and could result in a downgrade in debt ratings by credit rating agencies.

The terms of BHE's debt do not limit its ability or the ability of its subsidiaries to incur additional debt or issue preferred stock. Accordingly, BHE or its subsidiaries could enter into acquisitions, new financings, refinancings, recapitalizations, capital leases or other highly leveraged transactions that could significantly increase BHE's or its subsidiaries' total amount of outstanding debt. The interest payments needed to service this increased level of debt could adversely affect BHE's consolidated financial results. Many of BHE's subsidiaries' debt agreements contain covenants, or may in the future contain covenants, that restrict or limit, among other things, such subsidiaries' ability to create liens, sell assets, make certain distributions, incur additional debt or miss contractual deadlines or requirements, and BHE's ability to comply with these covenants may be affected by events beyond its control. Further, if an event of default accelerates a repayment obligation and such acceleration results in an event of default under some or all of BHE's other debt, BHE may not have sufficient funds to repay all of the accelerated debt simultaneously, and the other risks described under "Corporate and Financial Structure Risks" may be magnified as well.

Because BHE is a holding company, the claims of its senior debt holders are structurally subordinated with respect to the assets and earnings of its subsidiaries. Therefore, the rights of its creditors to participate in the assets of any subsidiary in the event of a liquidation or reorganization are subject to the prior claims of the subsidiary's creditors and preferred shareholders, if any. In addition, pursuant to separate financing agreements, substantially all of PacifiCorp's electric utility properties, MidAmerican Energy's electric utility properties in the state of Iowa, Nevada Power's and Sierra Pacific's properties and AltaLink's transmission properties, the equity interest of MidAmerican Funding's subsidiary, the long-term customer contracts of Kern River and substantially all of the assets of the subsidiaries of BHE Renewables that are direct or indirect owners of generation projects, are directly or indirectly pledged to secure their financings and, therefore, may be unavailable as potential sources of repayment of BHE's debt.

A downgrade in BHE's credit ratings or the credit ratings of its subsidiaries, including the Subsidiary Registrants, could negatively affect BHE's or its subsidiaries' access to capital, increase the cost of borrowing or raise energy transaction credit support requirements.

BHE's senior unsecured debt and its subsidiaries' long-term debt, including the Subsidiary Registrants, are rated by various rating agencies. BHE cannot give assurance that its senior unsecured debt rating or any of its subsidiaries' long-term debt ratings will not be reduced in the future. Although none of the Registrants' outstanding debt has rating-downgrade triggers that would accelerate a repayment obligation, a credit rating downgrade would increase any such Registrant's borrowing costs and commitment fees on its revolving credit agreements and other financing arrangements, perhaps significantly. In addition, such Registrant would likely be required to pay a higher interest rate in future financings, and the potential pool of investors and funding sources would likely decrease. Further, access to the commercial paper market, the principal source of short-term borrowings for each Registrant, could be significantly limited, resulting in higher interest costs.

Similarly, any downgrade or other event negatively affecting the credit ratings of BHE's subsidiaries could make their costs of borrowing higher or access to funding sources more limited, which in turn could cause BHE to provide liquidity in the form of capital contributions or loans to such subsidiaries, thus reducing its and its subsidiaries' liquidity and borrowing capacity.

Most of the Registrants' large wholesale customers, suppliers and counterparties require such Registrant to have sufficient creditworthiness in order to enter into transactions, particularly in the wholesale energy markets. If the credit ratings of a Registrant were to decline, especially below investment grade, the relevant Registrant's 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 such Registrant. Amounts may be material and may adversely affect such Registrant's liquidity and cash flows.

BHE's majority shareholder, Berkshire Hathaway, could exercise control over BHE in a manner that would benefit Berkshire Hathaway to the detriment of BHE's creditors and BHE could exercise control over the Subsidiary Registrants in a manner that would benefit BHE to the detriment of their creditors and PacifiCorp's ***preferred stockholders.***

Berkshire Hathaway is majority owner of BHE and has control over all decisions requiring shareholder approval. In circumstances involving a conflict of interest between Berkshire Hathaway and BHE's creditors, Berkshire Hathaway could exercise its control in a manner that would benefit Berkshire Hathaway to the detriment of BHE's creditors.

BHE indirectly owns all of the common stock of PacifiCorp, Nevada Power and Sierra Pacific and is the sole member of MidAmerican Funding and, accordingly, indirectly owns all of MidAmerican Energy's common stock. As a result, BHE has control over all decisions requiring shareholder approval, including the election of directors. In circumstances involving a conflict of interest between BHE and the creditors of the Subsidiary Registrants, and PacifiCorp's preferred stockholders, BHE could exercise its control in a manner that would benefit BHE to the detriment of their creditors and PacifiCorp's preferred stockholders.

Business Risks

Much of BHE's growth has been achieved through acquisitions, and any such acquisitions may not be successful.

Much of BHE's growth has been achieved through acquisitions. Future acquisitions may range from buying individual assets to the purchase of entire businesses. BHE will continue to investigate and pursue opportunities for future acquisitions that it believes, but cannot assure you, may increase value and expand or complement existing businesses. BHE may participate in bidding or other negotiations at any time for such acquisition opportunities which may or may not be successful.

Any acquisition entails numerous risks, including, among others:

- the failure to complete the transaction for various reasons, such as the inability to obtain the required regulatory approvals, materially adverse developments in the potential acquiree's business or financial condition or successful intervening offers by third parties;
- the failure of the combined business to realize the expected benefits;
- the risk that federal, state or foreign regulators or courts could require regulatory commitments or other actions in respect of acquired assets, potentially including programs, contributions, investments, divestitures and market mitigation measures;
- the risk of unexpected or unidentified issues not discovered in the diligence process; and
- the need for substantial additional capital and financial investments.

An acquisition could cause an interruption of, or a loss of momentum in, the activities of one or more of BHE's subsidiaries. In addition, the final orders of regulatory authorities approving acquisitions may be subject to appeal by third parties. The diversion of BHE management's attention and any delays or difficulties encountered in connection with the approval and integration of the acquired operations could adversely affect BHE's combined businesses and financial results and could impair its ability to realize the anticipated benefits of the acquisition.

BHE cannot assure you that future acquisitions, if any, or any integration efforts will be successful, or that BHE's ability to repay its obligations will not be adversely affected by any future acquisitions.

The Registrants are subject to operating uncertainties and events beyond each respective Registrant's control that impact the costs to operate, maintain, repair and replace utility and interstate natural gas pipeline systems, which could adversely affect each respective Registrant's consolidated financial results.

The operation of complex utility systems or interstate natural gas pipeline and storage systems that are spread over large geographic areas involves many operating uncertainties and events beyond each respective Registrant's control. These potential events include the breakdown or failure of the Registrants' thermal, nuclear, hydroelectric, wind and other electricity generating facilities and related equipment, compressors, pipelines, 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; failure to obtain, renew or maintain rights-of-way, easements and leases on United States federal, Native American, First Nations or tribal lands; terrorist activities or military or other actions, including cyber attacks; fuel shortages or interruptions; unavailability of critical equipment, materials and supplies; low water flows and other weather-related impacts; performance below expected levels of output, capacity or efficiency; operator error; third party excavation errors; unexpected degradation of pipeline systems; 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 PacifiCorp's high hazard potential hydroelectric dams, 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 the relevant Registrant's revenue or significantly increase its expenses, thereby reducing the availability of distributions to BHE. For example, if the relevant Registrant cannot operate its electricity or natural gas facilities at full capacity due to damage caused by a catastrophic event, its revenue could decrease and its expenses could increase due to the need to obtain energy from more expensive sources. Further, the Registrants 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 each Registrant's insurance coverage may change, including the portion that is self-insured. Any reduction of each Registrant's revenue or increase in its expenses resulting from the risks described above, could adversely affect the relevant Registrant's consolidated financial results.

Each Registrant is subject to extensive federal, state, local and foreign legislation and regulation, including numerous environmental, health, safety, reliability and other laws and regulations that affect its 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 each Registrant.

Each Registrant is required to comply with numerous federal, state, local and foreign laws and regulations as described in "General Regulation" and "Environmental Laws and Regulations" in Item 1 of this Form 10-K that have broad application to each Registrant and limits the respective Registrant's ability to independently make and implement management decisions regarding, among other items, acquiring businesses; constructing, acquiring or disposing of operating assets; operating and maintaining generating facilities and transmission and distribution system assets; complying with pipeline safety and integrity and environmental requirements; setting rates charged to customers; establishing capital structures and issuing debt or equity securities; transacting between subsidiaries and affiliates; and paying dividends or similar distributions. These laws and regulations are followed in developing the Registrants' 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 DOT, the NRC, the Federal Mine Safety and Health Administration and various state regulatory commissions in the United States, and foreign regulatory agencies, such as GEMA, which discharges certain of its powers through its staff within Ofgem, in Great Britain and the AUC in Alberta, Canada.

Compliance with applicable laws and regulations generally requires each Registrant 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, each Registrant could be required to shut down some facilities or materially alter its operations. Further, each Registrant may not be able to obtain or maintain all required environmental or other regulatory approvals and permits for its 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 each Registrant from operating its facilities, developing or favorably locating new facilities or expanding existing facilities. If any Registrant fails to comply with any environmental or other regulatory requirements, such Registrant may be subject to penalties and fines or other sanctions, including changes to the way its electricity generating facilities are operated that may adversely impact generation or how the Pipeline Companies are permitted to operate their systems that may adversely impact throughput. The costs of complying with laws and regulations could adversely affect each Registrant's consolidated financial results. Not being able to operate existing facilities or develop new generating facilities to meet customer electricity needs could require such Registrant to increase its purchases of electricity on the wholesale market, which could increase market and price risks and adversely affect such Registrant's 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 each Registrant's service territories; new environmental requirements, including the implementation of the Clean Power Plan, 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 each Registrant's service territories as a result of condemnation or takeover by municipalities or other governmental entities, particularly where it lacks the exclusive right to serve its customers; the inability of each Registrant to recover its costs on a timely basis, if at all; new pipeline safety requirements; or a negative impact on each Registrant's current transportation and cost recovery arrangements. 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 each Registrant.

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. The Registrants 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 each Registrant determine their impact on it at this time; however, any one of these could adversely affect each Registrant's consolidated financial results through higher capital expenditures and operating costs, and early closure of generating facilities or restrict or otherwise cause an adverse change in how each Registrant operates its business. To the extent that each Registrant is not allowed by its 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 the relevant Registrant's 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 the relevant Registrant's consolidated financial results.

Recovery of costs and certain activities by each Registrant is subject to regulatory review and approval, and the inability to recover costs or undertake certain activities may adversely affect each Registrant's consolidated financial results.

State Rate Proceedings

The Utilities establish rates for their 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 the Utilities 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 the Utilities will be given an opportunity to earn on their 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 each Registrant will be able to realize the allowed rate of return.

Energy cost increases above the level assumed in establishing base rates may be subject to customer sharing. Any significant increase in fuel costs for electricity generation or purchased electricity costs could have a negative impact on the Utilities, 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 each Registrant's consolidated financial results.

FERC Jurisdiction

The FERC authorizes cost-based rates associated with transmission services provided by the Utilities' transmission facilities. Under the Federal Power Act, the Utilities, or MISO as it relates to MidAmerican Energy, may voluntarily file, or may be obligated to file, for changes, including general rate changes, to their 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 the Utilities sell electricity at wholesale, has jurisdiction over most of PacifiCorp's 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 the ability of the Utilities to sell electricity at market-based rates, which could adversely affect each Registrant's consolidated financial results. The FERC also maintains rules concerning standards of conduct, affiliate restrictions, interlocking directorates and cross-subsidization. As a transmission owning member of the MISO, MidAmerican Energy is also subject to MISO-directed modifications of market rules, which are subject to FERC approval and operational procedures. As participants in EIM, PacifiCorp, Nevada Power and Sierra Pacific are also subject to applicable California ISO rules, which are subject to FERC approval and operational procedures. 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. The Utilities 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.

The FERC has jurisdiction over, among other things, the construction, abandonment, modification and operation of natural gas pipelines and related facilities used in the transportation, storage and sale of natural gas in interstate commerce, including all rates, charges and terms and conditions of service. The FERC also has market transparency authority and has adopted additional reporting and internet posting requirements for natural gas pipelines and buyers and sellers of natural gas.

Rates for the interstate natural gas transmission and storage operations at the Pipeline Companies, which include reservation, commodity, surcharges, fuel and gas lost and unaccounted for charges, are authorized by the FERC. In accordance with the FERC's rate-making principles, the Pipeline Companies' current maximum tariff rates are designed to recover prudently incurred costs included in their pipeline system's regulatory cost of service that are associated with the construction, operation and maintenance of their pipeline system and to afford the Pipeline Companies an opportunity to earn a reasonable rate of return. Nevertheless, the rates the FERC authorizes the Pipeline Companies to charge their customers may not be sufficient to recover the costs incurred to provide services in any given period. Moreover, from time to time, the FERC may change, alter or refine its policies or methodologies for establishing pipeline rates and terms and conditions of service. In addition, the FERC has the authority under Section 5 of the Natural Gas Act of 1938 ("NGA") to investigate whether a pipeline may be earning more than its allowed rate of return and, when appropriate, to institute proceedings against such pipeline to reduce rates. Any such proceedings, if instituted, could result in significantly adverse rate decreases.

Under FERC policy, interstate pipelines and their customers may execute contracts at negotiated rates, which may be above or below the maximum tariff rate for that service or the pipeline may agree to provide a discounted rate, which would be a rate between the maximum and minimum tariff rates. In a rate proceeding, rates in these contracts are generally not subject to adjustment. It is possible that the cost to perform services under negotiated or discounted rate contracts will exceed the cost used in the determination of the negotiated or discounted rates, which could result either in losses or lower rates of return for providing such services. FERC policy allows interstate natural gas pipelines to design new maximum tariff rates to recover such costs under certain circumstances in rate cases. However, with respect to discounts granted to affiliates, the interstate natural gas pipeline must demonstrate that the discounted rate was necessary in order to meet competition.

GEMA Jurisdiction

The Northern Powergrid Distribution Companies, as Distribution Network Operators ("DNOs") and holders of electricity distribution licenses, are subject to regulation by GEMA. Most of the revenue of a DNO is controlled by a distribution price control formula set out in the electricity distribution license. The price control formula does not directly constrain profits from year to year, but is a control on revenue that operates independently of most of the DNO's actual costs. A resetting of the formula does not require the consent of the DNO, but if a licensee disagrees with a change to its license it can appeal the matter to the United Kingdom's Competition and Markets Authority. GEMA is able to impose financial penalties on DNOs that contravene any of their electricity distribution license duties or certain of their duties under British law, or fail to achieve satisfactory performance of individual standards prescribed by GEMA. Any penalty imposed must be reasonable and may not exceed 10% of the DNO's revenue. During the term of any price control, additional costs have a direct impact on the financial results of the Northern Powergrid Distribution Companies.

AUC *Jurisdiction*

The AUC is an independent, quasi-judicial agency established by the province of Alberta, Canada, which is responsible for, among other things, approving the tariffs of transmission facility owners, including ALP, and distribution utilities, acquisitions of such transmission facility owners or utilities, and construction and operation of new transmission projects in Alberta. The AUC also investigates and rules on regulated rate disputes and system access problems.

The AUC regulates and oversees Alberta's electricity transmission sector with broad authority that may impact many of ALP's activities, including its tariffs, rates, construction, operations and financing. The AUC has various core functions in regulating the Alberta electricity transmission sector, including the following:

- regulating and adjudicating issues related to the operation of electric utilities within Alberta;
- processing and approving general tariff applications relating to revenue requirements and rates of return including deemed capital structure for regulated utilities while ensuring that utility rates are just and reasonable and approval of the transmission tariff rates of regulated transmission providers by the AESO, which is the independent transmission system operator in Alberta, Canada that controls the operation of AltaLink's transmission system;
- approving the need for new electricity transmission facilities and permits to build and licenses to operate electricity transmission facilities;
- reviewing operations and accounts from electric utilities and conducting on-site inspections to ensure compliance with industry regulation and standards;
- adjudicating enforcement issues including the imposition of administrative penalties that arise when market participants violate the rules of the AESO; and
- collecting, storing, analyzing, appraising and disseminating information to effectively fulfill its duties as an industry regulator.

In addition, AUC approval is required in connection with new energy and regulated utility initiatives in Alberta, amendments to existing approvals and financing proposals by designated utilities.

The AESO determines the need and plans for the expansion and enhancement of a congestion free transmission system in Alberta in accordance with applicable law and reliability standards. The AESO's responsibilities include long-term transmission planning and management, including assessing and planning for the current and future transmission system capacity needs of AESO market participants. When AESO determines an expansion or enhancement of the transmission system is needed, with limited exceptions, it submits an application to the AUC for approval of the proposed expansion or enhancement. The AESO then determines which transmission provider should submit an application to the AUC for a permit and license to construct and operate the designated transmission facilities. Generally the transmission provider operating in the geographic area where the transmission facilities expansion or enhancement is to be located is selected by the AESO to build, own and operate the transmission facilities. In addition, Alberta law provides that transmission projects may be subject to a competitive process open to qualifying bidders. In either case, there can be no assurance that any jurisdictional market participant that BHE may own, including AltaLink, will be selected by the AESO to build, own and operate transmission facilities, even if BHE's market participant operates in the relevant geographic area, or that BHE's market participant will be successful in any such competitive process in which it may participate.

Each Registrant is actively pursuing, developing and constructing new or expanded facilities, the completion and expected costs of which are subject to significant risk, and each Registrant has significant funding needs related to its planned capital expenditures.

Each Registrant actively pursues, develops and constructs new or expanded facilities. Each Registrant expects to incur significant annual capital expenditures over the next several years. Such expenditures may include construction and other costs for new electricity generating facilities, electric transmission or distribution projects, environmental control and compliance systems, natural gas storage facilities, new or expanded pipeline 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 the Registrants' suppliers, customers and contractors. Certain of the Registrants' construction projects are substantially dependent upon a single supplier or contractor and replacement of such supplier or 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 and, in extreme cases, the loss of the power purchase agreements or other long-term off-take contracts underlying such projects. Such costs may not be recoverable in the regulated rates or market or contract prices each Registrant is able to charge its customers. Delays in construction of renewable projects may result in delayed in-service dates which may result in the loss of anticipated revenue or income tax benefits. 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 such Registrant's consolidated financial results.

Furthermore, each Registrant depends upon both internal and external sources of liquidity to provide working capital and to fund capital requirements. If BHE does not provide needed funding to its subsidiaries and the subsidiaries are unable to obtain funding from external sources, they may need to postpone or cancel planned capital expenditures.

A significant sustained decrease in demand for electricity or natural gas in the markets served by each Registrant would decrease its operating revenue, could impact its planned capital expenditures and could adversely affect its consolidated financial results.

A significant sustained decrease in demand for electricity or natural gas in the markets served by each Registrant would decrease its operating revenue, could impact its planned capital expenditures and could adversely affect its 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 or natural gas;
- an increase in the market price of electricity or natural gas or a decrease in the price of other competing forms of energy;
- shifts in competitively priced natural gas supply sources away from the sources connected to the Pipeline Companies' systems, including new shale gas sources;
- efforts by customers, legislators and regulators to reduce the consumption of electricity generated or distributed by each Registrant through various existing laws and regulations, as well as, conservation, energy efficiency and distributed generation measures and programs;
- laws mandating or encouraging renewable energy sources, which may decrease the demand for electricity and natural gas or change the market prices of these commodities;
- higher fuel taxes or other governmental or regulatory actions that increase, directly or indirectly, the cost of natural gas or other fuel sources for electricity generation or that limit the use of natural gas or 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;
- a reduction in the state or federal subsidies or tax incentives that are provided to agricultural, industrial or other customers, or a significant sustained change in prices for commodities such as ethanol or corn for ethanol manufacturers; and
- sustained mild weather that reduces heating or cooling needs.

Each Registrant's operating results may fluctuate on a seasonal and quarterly basis and may be adversely affected by weather.

In most parts of the United States and other markets in which each Registrant operates, 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. In addition, demand for natural gas and other fuels generally peaks during the winter. This is especially true in Northern Natural Gas' traditional end-use and distribution market area and MidAmerican Energy's and Sierra Pacific's retail natural gas businesses. 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 PacifiCorp's hydroelectric generating facilities, which may result in greater purchases of electricity from the wholesale market or from other sources at market prices. Additionally, PacifiCorp and MidAmerican Energy have added substantial wind-powered generating capacity, and BHE's unregulated subsidiaries are adding solar and wind-powered generating capacity, each of which is also a climate-dependent resource.

As a result, the overall financial results of each Registrant may fluctuate substantially on a seasonal and quarterly basis. Each Registrant has historically provided less service, and consequently earned less income, when weather conditions are mild. Unusually mild weather in the future may adversely affect each Registrant's consolidated financial results through lower revenue or margins. Conversely, unusually extreme weather conditions could increase each Registrant's costs to provide services and could adversely affect its consolidated financial results. The extent of fluctuation in each Registrant's consolidated financial results may change depending on a number of factors related to its regulatory environment and contractual agreements, including its ability to recover energy costs, the existence of revenue sharing provisions as it relates to MidAmerican Energy, and terms of its wholesale sale contracts.

Each Registrant is subject to market risk associated with the wholesale energy markets, which could adversely affect its consolidated financial results.

In general, each Registrant's 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, the Utilities purchase electricity and fuel in the open market as part of their normal operating businesses. If market prices rise, especially in a time when larger than expected volumes must be purchased at market prices, the Utilities may incur significantly greater expense than anticipated. Likewise, if electricity market prices decline in a period when the Utilities are a net seller of electricity in the wholesale market, the Utilities could earn less revenue. Although the Utilities have energy cost adjustment mechanisms, the risks associated with changes in market prices may not be fully mitigated due to customer sharing bands as it relates to PacifiCorp and other factors.

Potential terrorist activities and the impact of military or other actions, could adversely affect each Registrant's 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 each Registrant's operations to increased risks. Additionally, the United States government has issued warnings that energy assets, specifically pipeline, nuclear generation, transmission and other electric utility infrastructure, are potential targets for terrorist attacks. Political, economic, social or financial market instability or damage to or interference with the operating assets of the Registrants, 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 each Registrant in ways that cannot be predicted at this time. Any of these risks could materially affect its consolidated financial results. Furthermore, instability in the financial markets as a result of terrorism or war could also materially adversely affect each Registrant's ability to raise capital.

Physical or cyber attacks, both threatened and actual, could impact each Registrant's operations and could adversely affect its consolidated financial results.

Each Registrant relies on information technology in virtually all aspects of its business. A significant disruption or failure of its information technology systems by physical or cyber attack could result in service interruptions, safety failures, security violations, regulatory compliance failures, an inability to protect corporate information assets against intruders, and other operational difficulties. Attacks perpetrated against each Registrant's information systems could result in loss of assets and critical information and expose it to remediation costs and reputational damage.

Although the Registrants have taken steps intended to mitigate these risks, including business continuity planning, disaster recovery planning and business impact analysis, a significant disruption or cyber intrusion could lead to misappropriation of assets or data corruption and could adversely affect each Registrant's results of operations, financial condition or liquidity. Additionally, if each Registrant is unable to acquire or implement new technology, it may suffer a competitive disadvantage, which could also have an adverse effect on its results of operations, financial condition or liquidity. Cyber attacks could further adversely affect each Registrant's ability to operate facilities, information technology and business systems, or compromise confidential customer and employee information. In addition, physical or cyber attacks against key suppliers or service providers could have a similar effect on each Registrant.

Certain Registrants are subject to the unique risks associated with nuclear generation.

The ownership and operation of nuclear power plants, such as MidAmerican Energy's 25% ownership interest in Quad Cities Station, involves certain risks. These risks include, among other items, mechanical or structural problems, inadequacy or lapses in maintenance protocols, the impairment of reactor operation and safety systems due to human error, the costs of storage, handling and disposal of nuclear materials, compliance with and changes in regulation of nuclear power plants, limitations on the amounts and types of insurance coverage commercially available, and uncertainties with respect to the technological and financial aspects of decommissioning nuclear facilities at the end of their useful lives. Additionally, Exelon Generation, the 75% owner and operator of the facility, may respond to the occurrence of any of these or other risks in a manner that negatively impacts MidAmerican Energy, including closure of Quad Cities Station prior to the expiration of its operating license. The prolonged unavailability, or early closure, of Quad Cities Station due to operational or economic factors could have a materially adverse effect on the relevant Registrant's financial results, particularly when the cost to produce power at the plant is significantly less than market wholesale prices. The following are among the more significant of these risks:

- *Operational Risk* - Operations at any nuclear power plant could degrade to the point where the plant would have to be shut down. If such degradations were to occur, the process of identifying and correcting the causes of the operational downgrade to return the plant to operation could require significant time and expense, resulting in both lost revenue and increased fuel and purchased electricity costs to meet supply commitments. Rather than incurring substantial costs to restart the plant, the plant could be shut down. Furthermore, a shut-down or failure at any other nuclear power plant could cause regulators to require a shut-down or reduced availability at Quad Cities Station.

  In addition, issues relating to the disposal of nuclear waste material, including the availability, unavailability and expense of a permanent repository for spent nuclear fuel could adversely impact operations as well as the cost and ability to decommission nuclear power plants, including Quad Cities Station, in the future.

- *Regulatory Risk* - The NRC may modify, suspend or revoke licenses and impose civil penalties for failure to comply with applicable Atomic Energy Act regulations or the terms of the licenses of nuclear facilities. Unless extended, the NRC operating licenses for Quad Cities Station will expire in 2032. Changes in regulations by the NRC could require a substantial increase in capital expenditures or result in increased operating or decommissioning costs.
- *Nuclear Accident and Catastrophic Risks* - Accidents and other unforeseen catastrophic events have occurred at nuclear facilities other than Quad Cities Station, both in the United States and elsewhere, such as at the Fukushima Daiichi nuclear power plant in Japan as a result of the earthquake and tsunami in March 2011. The consequences of an accident or catastrophic event can be severe and include loss of life and property damage. Any resulting liability from a nuclear accident or catastrophic event could exceed the relevant Registrant's resources, including insurance coverage.

Certain of BHE's subsidiaries are subject to the risk that customers will not renew their contracts or that BHE's subsidiaries will be unable to obtain new customers for expanded capacity, each of which could adversely affect its consolidated financial results.

Substantially all of the Pipeline Companies' revenues are generated under transportation and storage contracts that periodically must be renegotiated and extended or replaced, and the Pipeline Companies are dependent upon relatively few customers for a substantial portion of their revenue. If BHE's subsidiaries are unable to renew, remarket, or find replacements for their customer agreements on favorable terms, BHE's subsidiaries' sales volumes and operating revenue would be exposed to reduction and increased volatility. For example, without the benefit of long-term transportation agreements, BHE cannot assure that the Pipeline Companies will be able to transport natural gas at efficient capacity levels. Similarly, without long-term power purchase agreements, BHE cannot assure that its unregulated power generators will be able to operate profitably. Failure to maintain existing long-term agreements or secure new long-term agreements, or being required to discount rates significantly upon renewal or replacement, could adversely affect BHE's consolidated financial results. The replacement of any existing long-term agreements depends on market conditions and other factors that may be beyond BHE's subsidiaries' control.

Each Registrant is subject to counterparty risk, which could adversely affect its consolidated financial results.

Each Registrant is 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 each Registrant conducts business could impair the ability of these counterparties to meet their payment obligations. Each Registrant depends on these counterparties to remit payments on a timely basis. Each Registrant continues to monitor the creditworthiness of its 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 any Registrant's wholesale suppliers' or customers' financial condition deteriorates or they otherwise become unable to pay, it could have a significant adverse impact on each Registrant's liquidity and its consolidated financial results.

Each Registrant is subject to counterparty performance risk related to performance of contractual obligations by wholesale suppliers, customers and contractors. Each Registrant relies 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 the Utilities to incur additional expenses to meet customer needs. In addition, when these contracts terminate, the Utilities may be unable to purchase the commodities on terms equivalent to the terms of current contracts.

Each Registrant relies on wholesale customers to take delivery of the energy they have committed to purchase. Failure of customers to take delivery may require the relevant Registrant to find other customers to take the energy at lower prices than the original customers committed to pay. If each Registrant's wholesale customers are unable to fulfill their obligations, there may be a significant adverse impact on its consolidated financial results.

Generally, a single customer purchases the energy from Berkshire Hathaway Energy's independent power projects in the United States and the Philippines pursuant to long-term power purchase agreements. Without performance by the counterparties under these agreements, Berkshire Hathaway Energy cannot assure that its unregulated power generators will be able to operate profitably.

BHE owns investments and projects in foreign countries that are exposed to risks related to fluctuations in foreign currency exchange rates and increased economic, regulatory and political risks.

BHE's business operations and investments outside the United States increase its risk related to fluctuations in foreign currency exchange rates, primarily the British pound and the Canadian dollar. BHE's principal reporting currency is the United States dollar, and the value of the assets and liabilities, earnings, cash flows and potential distributions from its foreign operations changes with the fluctuations of the currency in which they transact. BHE may selectively reduce some foreign currency exchange rate risk by, among other things, requiring contracted amounts be settled in, or indexed to, United States dollars or a currency freely convertible into United States dollars, or hedging through foreign currency derivatives. These efforts, however, may not be effective and could negatively affect BHE's consolidated financial results.

BHE indirectly owns a hydroelectric power plant in the Philippines and may acquire significant energy-related investments and projects outside of the United States. In addition to any disruption in the global financial markets, the economic, regulatory and political conditions in some of the countries where BHE has operations or is pursuing investment opportunities may present increased risks related to, among others, inflation, foreign currency exchange rate fluctuations, currency repatriation restrictions, nationalization, renegotiation, privatization, availability of financing on suitable terms, customer creditworthiness, construction delays, business interruption, political instability, civil unrest, guerilla activity, terrorism, expropriation, trade sanctions, contract nullification and changes in law, regulations or tax policy. BHE may not choose to or be capable of either fully insuring against or effectively hedging these risks.

Poor performance of plan and fund investments and other factors impacting the pension and other postretirement benefit plans and nuclear decommissioning and mine reclamation trust funds could unfavorably impact each Registrant's cash flows and liquidity.

Costs of providing each Registrant's defined benefit pension and other postretirement benefit plans and costs associated with the joint trustee plan to which PacifiCorp contributes 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 each Registrant's required or voluntary contributions made to the plans. Certain of the Registrant's pension and other postretirement benefit plans are in underfunded positions. Even if sustained growth in the investments over future periods increases the value of these plans' assets, each Registrant will likely be required to make cash contributions to fund these plans in the future. Additionally, each Registrant's plans has investments in domestic and foreign equity and debt securities and other investments that are subject to loss. Losses from investments could add to the volatility, size and timing of future contributions.

Furthermore, the funded status of the UMWA 1974 Pension Plan multiemployer plan to which PacifiCorp's subsidiary previously contributed is considered critical and declining. PacifiCorp's subsidiary involuntarily withdrew from the UMWA 1974 Pension Plan in June 2015 when the UMWA employees ceased performing work for the subsidiary. PacifiCorp has recorded its best estimate of the withdrawal obligation. 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 withdrew during the three years prior to a mass withdrawal.

In addition, MidAmerican Energy is required to fund over time the projected costs of decommissioning Quad Cities Station, a nuclear power plant, and Bridger Coal Company, a joint venture of PacifiCorp's subsidiary, Pacific Minerals, Inc., is required to fund projected mine reclamation costs. Funds that MidAmerican Energy has invested in a nuclear decommissioning trust and PacifiCorp has invested in a mine reclamation trust 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 MidAmerican Energy or PacifiCorp 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 MidAmerican Energy's or PacifiCorp's liquidity by reducing their available cash.

Inflation and changes in commodity prices and fuel transportation costs may adversely affect each Registrant's consolidated financial results.

Inflation and increases in commodity prices and fuel transportation costs may affect each Registrant by increasing both operating and capital costs. As a result of existing rate agreements, contractual arrangements or competitive price pressures, each Registrant may not be able to pass the costs of inflation on to its customers. If each Registrant is unable to manage cost increases or pass them on to its customers, its consolidated financial results could be adversely affected.

Cyclical fluctuations in the residential real estate brokerage and mortgage businesses could adversely affect HomeServices.

The residential real estate brokerage and mortgage industries tend to experience cycles of greater and lesser activity and profitability and are typically affected by changes in economic conditions, which are beyond HomeServices' control. Any of the following, among others, are examples of items that could have a material adverse effect on HomeServices' businesses by causing a general decline in the number of home sales, sale prices or the number of home financings which, in turn, would adversely affect its financial results:

- rising interest rates or unemployment rates, including a sustained high unemployment rate in the United States;
- periods of economic slowdown or recession in the markets served;
- decreasing home affordability;
- lack of available mortgage credit for potential homebuyers, such as the reduced availability of credit, which may continue into future periods;
- declining demand for residential real estate as an investment;
- nontraditional sources of new competition; and
- changes in applicable tax law.

Disruptions in the financial markets could affect each Registrant's ability to obtain debt financing or to draw upon or renew existing credit facilities and have other adverse effects on each Registrant.

Disruptions in the financial markets could affect each Registrant's ability to obtain debt financing or to draw upon or renew existing credit facilities and have other adverse effects on each Registrant. Significant dislocations and liquidity disruptions in the United States, Great Britain, Canada 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 each Registrant's ability to access funds on favorable terms or at all. If each Registrant is unable to access the bank and debt markets to meet liquidity and capital expenditure needs, it may adversely affect the timing and amount of its capital expenditures, acquisition financing and its consolidated financial results.

Each Registrant is involved in a variety of legal proceedings, the outcomes of which are uncertain and could adversely affect its consolidated financial results.

Each Registrant is, and in the future may become, a party to a variety of legal proceedings. Litigation is subject to many uncertainties, and the Registrants cannot predict the outcome of individual matters with certainty. It is possible that the final resolution of some of the matters in which each Registrant is involved could result in additional material payments substantially in excess of established reserves or in terms that could require each Registrant to 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 each Registrant's ability to take certain desired actions or the denial of needed permits, licenses or regulatory authority to conduct its business, including the siting or permitting of facilities. Any of these outcomes could have a material adverse effect on such Registrant's consolidated financial results.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 2. Properties

Each Registrant's energy properties consist of the physical assets necessary to support its applicable electricity and natural gas businesses. Properties of the relevant Registrant's electricity businesses include electric generation, transmission and distribution facilities, as well as coal mining assets that support certain of PacifiCorp's electric generating facilities. Properties of the relevant Registrant's natural gas businesses include natural gas distribution facilities, interstate pipelines, storage facilities, compressor stations and meter stations. In addition to these physical assets, the Registrants have rights-of-way, mineral rights and water rights that enable each Registrant to utilize its facilities. It is the opinion of each Registrant's management that the principal depreciable properties owned by it are in good operating condition and are well maintained. Pursuant to separate financing agreements, substantially all of PacifiCorp's electric utility properties, MidAmerican Energy's electric utility properties in the state of Iowa, Nevada Power's and Sierra Pacific's properties in the state of Nevada, AltaLink's transmission properties and substantially all of the assets of the subsidiaries of BHE Renewables are pledged or encumbered to support or otherwise provide the security for their related subsidiary debt. For additional information regarding each Registrant's energy properties, refer to Item 1 of this Form 10-K and Notes 4, 5 and 21 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K, Notes 3 and 4 of the Notes to Consolidated Financial Statements of PacifiCorp in Item 8 of this Form 10-K, Notes 3 and 8 of the Notes to Financial Statements of MidAmerican Energy in Item 8 of this Form 10-K, Notes 3 and 4 of the Notes to Consolidated Financial Statements of Nevada Power in Item 8 of this Form 10-K and Notes 3 and 4 of the Notes to Consolidated Financial Statements of Sierra Pacific in Item 8 of this Form 10-K.

The following table summarizes Berkshire Hathaway Energy's electric generating facilities that are in operation as of December 31, 2015:

Energy Source	Entity	Location by Significance	Facility Net Capacity (MW)	Net Owned Capacity (MW)
Natural gas	PacifiCorp, MidAmerican Energy, NV Energy and BHE Renewables	Nevada, Utah, Iowa, Illinois, Washington, Oregon, New York, Texas and Arizona	10,943	10,534
Coal	PacifiCorp, MidAmerican Energy and NV Energy	Iowa, Wyoming, Arizona, Utah, Montana, Colorado and Nevada	16,864	9,798
Wind	PacifiCorp, MidAmerican Energy and BHE Renewables	Iowa, Wyoming, Washington, California, Texas, Oregon and Illinois	5,133	5,124
Solar	BHE Renewables and NV Energy	California, Arizona and Nevada	1,441	1,293
Hydroelectric	PacifiCorp, MidAmerican Energy and BHE Renewables	Washington, Oregon, The Philippines, Idaho, California, Utah, Hawaii, Montana, Wyoming and Illinois	1,297	1,275
Nuclear	MidAmerican Energy	Illinois	1,824	456
Geothermal	PacifiCorp and BHE Renewables	California and Utah	370	370
		Total	37,872	28,850

Additionally, Berkshire Hathaway Energy has electric generating facilities that are under construction in Iowa, Nebraska and Kansas as of December 31, 2015 having total Facility Net Capacity and Net Owned Capacity of 1,066 MW.

The right to construct and operate each Registrant's electric transmission and distribution facilities and interstate natural gas pipelines across certain property was obtained in most circumstances through negotiations and, where necessary, through the exercise of the power of eminent domain or similar rights. PacifiCorp, MidAmerican Energy, Nevada Power, Sierra Pacific, Northern Natural Gas and Kern River in the United States; Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc in Great Britain; and AltaLink in Alberta, Canada continue to have the power of eminent domain or similar rights in each of the jurisdictions in which they operate their respective facilities, but the United States and Canadian utilities do not have the power of eminent domain with respect to governmental or Native American and Canadian First Nations' tribal lands. Although the main Kern River pipeline crosses the Moapa Indian Reservation, all facilities in the Moapa Indian Reservation are located within a utility corridor that is reserved to the United States Department of Interior, Bureau of Land Management.

With respect to real property, each of the electric transmission and distribution facilities and interstate natural gas pipelines fall into two basic categories: (1) parcels that are owned in fee, such as certain of the electric generating facilities, electric substations, natural gas compressor stations, natural gas meter stations 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 electric transmission and distribution facilities and interstate natural gas pipelines. Each Registrant believes it has satisfactory title or interest to all of the real property making up their respective facilities in all material respects.

Item 3. Legal Proceedings

Each Registrant is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. Each Registrant does not believe that such normal and routine litigation will have a material impact on its consolidated financial results. Each Registrant 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 the Notes to Consolidated Financial Statements of PacifiCorp in Item 8 of this Form 10-K for information regarding legal proceedings.

Item 4. Mine Safety Disclosures

Information regarding Berkshire Hathaway Energy's and 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

BERKSHIRE HATHAWAY ENERGY

BHE's common stock is owned by Berkshire Hathaway, Mr. Walter Scott, Jr., a member of BHE's Board of Directors (along with family members and related entities), and Mr. Gregory E. Abel, BHE's Chairman, President and Chief Executive Officer, and has not been registered with the SEC pursuant to the Securities Act of 1933, as amended, listed on a stock exchange or otherwise publicly held or traded. BHE has not declared or paid any cash dividends to its common shareholders since Berkshire Hathaway acquired an equity ownership interest in BHE in March 2000, and does not presently anticipate that it will declare any dividends on its common stock in the foreseeable future.

For a discussion of restrictions that limit BHE's and its subsidiaries' ability to pay dividends on their common stock, refer to Note 17 of the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K.

PACIFICORP

All common stock of PacifiCorp is held by its parent company, PPW Holdings LLC, which is a direct, wholly owned subsidiary of BHE.

PacifiCorp declared and paid dividends to PPW Holdings LLC of $950 million in 2015 and $725 million in 2014.

For a discussion of regulatory restrictions that limit PacifiCorp's ability to pay dividends on common stock, refer to "Limitations" in PacifiCorp's Item 7 in this Form 10-K and Note 15 of the Notes to Consolidated Financial Statements of PacifiCorp in Item 8 of this Form 10-K.

MIDAMERICAN FUNDING AND MIDAMERICAN ENERGY

All common stock of MidAmerican Energy is held by its parent company, MHC, which is a direct, wholly owned subsidiary of MidAmerican Funding. MidAmerican Funding is an Iowa limited liability company whose membership interest is held solely by BHE.

For a discussion of regulatory restrictions that limit MidAmerican Energy's ability to pay dividends on common stock, refer to "Debt Authorizations and Related Matters" in MidAmerican Energy's Item 7 in this Form 10-K and to Note 8 of the Notes to Financial Statements of MidAmerican Energy in Item 8 of this Form 10-K.

NEVADA POWER

All of Nevada Power's common stock is held by its parent company, NV Energy, which is an indirect, wholly owned subsidiary of BHE.

Nevada Power declared and paid dividends to NV Energy of $13 million in 2015 and $230 million in 2014.

SIERRA PACIFIC

All of Sierra Pacific's common stock is held by its parent company, NV Energy, which is an indirect, wholly owned subsidiary of BHE.

Sierra Pacific declared and paid dividends to NV Energy of $7 million in 2015 and $105 million in 2014.

Item 8. Financial Statements and Supplementary Data

Berkshire Hathaway Energy Company and its subsidiaries
Consolidated Financial Section

Item 6. Selected Financial Data

The following table sets forth the Company'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 the Company'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 the Company's audited historical Consolidated Financial Statements and notes thereto (in millions).

	Years Ended December 31,				
	2015(1)	2014(1)	2013(1)	2012	2011
Consolidated Statement of Operations Data:					
Operating revenue	$ 17,880	$ 17,326	$ 12,635	$ 11,548	$ 11,173
Net income	2,400	2,122	1,676	1,495	1,352
Net income attributable to BHE shareholders	2,370	2,095	1,636	1,472	1,331

	As of December 31,				
	2015(1)	2014(1)	2013(1)	2012	2011
Consolidated Balance Sheet Data:					
Total assets(2)(3)	$ 83,618	$ 81,816	$ 69,591	$ 52,212	$ 47,457
Short-term debt	974	1,445	232	887	865
Long-term debt, including current maturities:					
BHE senior debt(3)	7,814	7,810	6,575	4,592	5,333
BHE subordinated debt	2,944	3,794	2,594	—	22
Subsidiary debt(3)	27,214	26,848	22,645	16,007	13,605
Total BHE shareholders' equity	22,401	20,442	18,711	15,742	14,092

(1) Reflects the completion of the AltaLink acquisition from December 1, 2014 and the NV Energy acquisition from December 19, 2013.

(2) In December 2015, the Company retrospectively adopted Accounting Standards Update No. 2015-17, which resulted in the reclassification of certain deferred income tax balances previously recognized within other current assets in the amounts of $291 million, $211 million, $119 million, and $149 million, as of December 31, 2014, 2013, 2012 and 2011, respectively, as reductions in noncurrent deferred income tax liabilities.

(3) In December 2015, the Company retrospectively adopted Accounting Standards Update 2015-03, which resulted in the reclassification of certain deferred debt issuance costs previously recognized within other assets in the amounts of $50 million, $41 million, $29 million, and $30 million, as of December 31, 2014, 2013, 2012 and 2011, respectively, as reductions in BHE senior debt, and certain deferred debt issuance costs previously recognized within other assets in the amounts of $147 million, $157 million, $107 million, and $82 million, as of December 31, 2014, 2013, 2012 and 2011, respectively, as reductions in subsidiary debt.

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 the Company 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 the Company's historical Consolidated Financial Statements and Notes to Consolidated Financial Statements in Item 8 of this Form 10-K. The Company's actual results in the future could differ significantly from the historical results.

The reportable segment financial information includes all necessary adjustments and eliminations needed to conform to the Company's significant accounting policies. The differences between the reportable segment amounts and the consolidated amounts, described as "BHE and Other," relate principally to other entities, corporate functions and intersegment eliminations. BHE U.S. Transmission was previously included in BHE and Other.

Results of Operations

Overview

Net income for the Company's reportable segments for the years ended December 31 is summarized as follows (in millions):

	2015	2014	Change		2014	2013	Change	
Net income attributable to BHE shareholders:								
PacifiCorp	$ 697	$ 700	$ (3)	— %	$ 700	$ 681	$ 19	3%
MidAmerican Funding	458	409	49	12	409	340	69	20
NV Energy	379	354	25	7	354	(43)	397	*
Northern Powergrid	422	412	10	2	412	335	77	23
BHE Pipeline Group	243	230	13	6	230	237	(7)	(3)
BHE Transmission	186	56	130	*	56	33	23	70
BHE Renewables	124	121	3	2	121	(20)	141	*
HomeServices	104	83	21	25	83	73	10	14
BHE and Other	(243)	(270)	27	10	(270)	—	(270)	*
Total net income attributable to BHE shareholders	$ 2,370	$ 2,095	$ 275	13	$ 2,095	$ 1,636	$ 459	28

* Not meaningful

Net income attributable to BHE shareholders increased $275 million for 2015 compared to 2014 due to the following:

- PacifiCorp's net income decreased due to the prior year recognition of insurance recoveries for a fire claim, higher depreciation and amortization of $35 million, lower AFUDC of $25 million and higher property taxes, partially offset by higher margins of $109 million and lower production tax credits of $9 million. Margins increased primarily due to higher retail rates, lower purchased electricity prices, lower natural gas generation and costs, Utah mine disposition costs in 2014 and lower coal generation, partially offset by higher purchased electricity volumes, lower wholesale electricity revenue from lower volumes and prices and lower retail customer load. Customer load decreased 0.7% due to lower industrial customer usage in Utah and Wyoming and lower residential customer usage across the service territory, partially offset by an increase in the average number of residential customers in Utah and Oregon, an increase in the average number of commercial customers in Utah and the impacts of weather on residential, commercial and irrigation customer loads.

- MidAmerican Funding's net income increased due to higher regulated electric margins of $119 million, higher production tax credits of $27 million and lower fossil-fueled generation maintenance of $10 million, partially offset by higher depreciation and amortization of $56 million due to wind-powered generation and other plant placed in-service, lower AFUDC of $27 million, lower regulated natural gas margins of $12 million due to warmer temperatures in 2015 and higher interest expense of $9 million due to the issuance of first mortgage bonds in April 2014 and October 2015. Regulated electric margins increased primarily due to higher retail rates in Iowa and changes in rate structure related to seasonal pricing, lower purchased power costs, a lower average cost of fuel for generation and higher transmission revenue, partially offset by lower wholesale revenue. Electric retail customer load increased 1.2% as a result of strong industrial growth, partially offset by warmer winter temperatures compared to 2014.
- NV Energy's net income increased due to higher electric margins of $76 million and lower interest expense of $21 million, partially offset by higher depreciation and amortization of $31 million due to higher regulatory amortizations and higher operating expense of $30 million, primarily related to energy efficiency costs. Electric margins increased primarily due to higher electric retail customer load of 2.4% from increased customer usage and growth and the impacts of weather.
- Northern Powergrid's net income increased due to income tax benefits of $41 million from a 2% reduction in the United Kingdom corporate income tax rate, higher distribution revenue from recovery of the December 2013 customer rebate and favorable movements in regulatory provisions, and lower write-offs of hydrocarbon well exploration costs of $22 million, partially offset by lower tariff rates and distributed units and the stronger United States dollar of $34 million.
- BHE Pipeline Group's net income increased due to lower operating expenses of $28 million primarily at Northern Natural Gas as a result of lower in-line inspection, hydrostatic testing and other maintenance project costs and higher transportation revenues of $7 million, partially offset by higher depreciation expense of $8 million and lower other income of $6 million due to a contract restructuring at Northern Natural Gas that expired in 2015.
- BHE Transmission's net income increased due to the acquisition of AltaLink on December 1, 2014 totaling $120 million and lower operating expense primarily related to lower acquisition and project development costs.
- BHE Renewables' net income increased $18 million from solar projects primarily due to additional solar capacity at the Solar Star and Topaz Projects being placed in-service, partially offset by lower earnings of $18 million at CE Generation due to lower revenue from lower short run avoided cost pricing.
- HomeServices' net income increased due to higher earnings at existing brokerage, mortgage and franchise businesses, due to higher closed units, and acquired brokerage businesses, partially offset by $12 million of gains in 2014 from the acquisition of interests in equity method investments.
- BHE and Other net loss decreased due to lower income tax expense from favorable consolidated state income tax benefits and United States income taxes on foreign earnings, partially offset by higher interest expense from debt issuances in the fourth quarter of 2014.

Net income attributable to BHE shareholders increased $459 million for 2014 compared to 2013 due to the following:

- PacifiCorp's net income increased due to higher retail rates, the 2014 recognition of insurance recoveries for a fire claim and related charges in 2013, and higher average wholesale prices, partially offset by higher energy costs, lower retail customer load and higher depreciation and amortization due to the impact of a depreciation rate study effective in 2014 and higher plant in-service.
- MidAmerican Funding's net income increased due to improved regulated electric margins from higher electric retail rates in Iowa, net of the impact of cooler summer temperatures in 2014, higher natural gas margins from colder winter temperatures in 2014, lower depreciation and amortization primarily from the impact of depreciation rate changes and higher AFUDC, partially offset by higher operating and interest expense.
- NV Energy was acquired on December 19, 2013, and its results are included in the consolidated results beginning as of that date. Net income for 2014 totaled $354 million. The net loss for 2013 reflects a one-time bill credit to retail customers of $13 million, after-tax, charges under NV Energy's change in control policy of $19 million, after-tax, and contributions to the NV Energy Foundation of $11 million, after-tax.
- Northern Powergrid's net income increased due to higher tariff rates, a one-time rebate to customers in December 2013, favorable movements in regulatory provisions in 2014 and the weaker United States dollar of $26 million, partially offset by deferred income tax benefits in 2013 of $54 million from reductions in the United Kingdom corporate income tax rate, lower distributed units and write-offs of hydrocarbon well costs.

- BHE Pipeline Group's net income decreased due to higher operating expense primarily at Northern Natural Gas as a result of higher in-line inspection, hydrostatic testing and other maintenance project costs, benefits from a contract restructuring in 2013 at Northern Natural Gas and higher depreciation and amortization, partially offset by higher transportation revenue at Northern Natural Gas due to greater volumes from colder temperatures.
- BHE Transmission's net income increased due to the acquisition of AltaLink on December 1, 2014 totaling $13 million and higher equity earnings at ETT due to continued investment and additional plant placed in-service, partially offset by higher operating expense primarily related to higher project development costs.
- BHE Renewables' net income increased due to higher earnings from the Topaz and Solar Star Projects as additional solar capacity was placed in-service and a non-recurring goodwill impairment at CE Generation in the fourth quarter of 2013, partially offset by unfavorable changes in the valuation of the power purchase agreement derivative at Bishop Hill II and the interest rate swaps at the Pinyon Pines Projects.
- HomeServices' net income increased due to higher earnings at newly acquired businesses, partially offset by lower earnings at existing franchise, brokerage and mortgage businesses due to lower units and lower overall real estate purchase and refinancing activity.
- BHE and Other net loss increased due to higher interest expense from debt issuances in the fourth quarter of 2014 and 2013, one-time state deferred income tax benefits recognized in 2013 from a reduction in the apportioned state tax rate of $161 million, in part, as a result of the acquisition of NV Energy and higher charitable contributions.

Reportable Segment Results

Operating revenue and operating income for the Company's reportable segments for the years ended December 31 are summarized as follows (in millions):

	2015	2014	Change		2014	2013	Change	
Operating revenue:								
PacifiCorp	$ 5,232	$ 5,252	$ (20)	— %	$ 5,252	$ 5,147	$ 105	2%
MidAmerican Funding	3,420	3,762	(342)	(9)	3,762	3,413	349	10
NV Energy	3,351	3,241	110	3	3,241	(20)	3,261	*
Northern Powergrid	1,140	1,283	(143)	(11)	1,283	1,025	258	25
BHE Pipeline Group	1,016	1,078	(62)	(6)	1,078	952	126	13
BHE Transmission	592	62	530	*	62	—	62	*
BHE Renewables	728	623	105	17	623	355	268	75
HomeServices	2,526	2,144	382	18	2,144	1,809	335	19
BHE and Other	(125)	(119)	(6)	(5)	(119)	(46)	(73)	*
Total operating revenue	$ 17,880	$ 17,326	$ 554	3	$ 17,326	$ 12,635	$ 4,691	37
Operating income:								
PacifiCorp	$ 1,344	$ 1,308	$ 36	3 %	$ 1,308	$ 1,275	$ 33	3%
MidAmerican Funding	473	423	50	12	423	357	66	18
NV Energy	812	791	21	3	791	(42)	833	*
Northern Powergrid	593	674	(81)	(12)	674	501	173	35
BHE Pipeline Group	464	439	25	6	439	446	(7)	(2)
BHE Transmission	260	16	244	*	16	(5)	21	*
BHE Renewables	255	314	(59)	(19)	314	223	91	41
HomeServices	184	125	59	47	125	129	(4)	(3)
BHE and Other	(57)	(44)	(13)	(30)	(44)	(49)	5	10
Total operating income	$ 4,328	$ 4,046	$ 282	7	$ 4,046	$ 2,835	$ 1,211	43

* Not meaningful

PacifiCorp

Operating revenue decreased $20 million for 2015 compared to 2014 due to lower wholesale and other revenue of $113 million, partially offset by higher retail revenue of $93 million. Wholesale and other revenue decreased due to lower wholesale volumes of $55 million, lower REC revenue of $31 million and lower average wholesale prices of $27 million. The increase in retail revenue was due to higher retail rates of $109 million, partially offset by lower retail customer load of $16 million. Customer load decreased 0.7% due to lower industrial customer usage in Utah and Wyoming and lower residential customer usage across the service territory, partially offset by an increase in the average number of residential customers in Utah and Oregon, an increase in the average number of commercial customers in Utah and the impacts of weather on residential, commercial and irrigation customer loads.

Operating income increased $36 million for 2015 compared to 2014 due to higher margins of $109 million, partially offset by the prior year recognition of insurance recoveries for a fire claim, higher depreciation and amortization of $35 million primarily due to higher plant in-service including the Lake Side 2 natural gas-fueled generating facility ("Lake Side 2") placed in-service in May 2014 and higher property taxes. Margins increased due to lower energy costs of $129 million, partially offset by the lower operating revenue. Energy costs decreased due to lower purchased electricity prices, lower natural gas generation, lower average cost of natural gas, Utah mine disposition costs in 2014 and lower coal generation, partially offset by higher purchased electricity volumes and lower net deferrals of incurred net power costs.

Operating revenue increased $105 million for 2014 compared to 2013 due to higher retail revenue of $73 million and higher wholesale and other revenue of $32 million. The increase in retail revenue was due to higher rates of $144 million, partially offset by lower retail customer load of $71 million. Customer load decreased 1.2% 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. Wholesale and other revenue increased primarily due to higher average wholesale prices of $26 million, partially offset by lower REC revenue of $9 million.

Operating income increased $33 million for 2014 compared to 2013 due to the higher operating revenue and the 2014 recognition of insurance recoveries for a fire claim and related charges in 2013, partially offset by higher energy costs of $73 million, higher depreciation and amortization of $53 million, due to the impact of a depreciation rate study effective in 2014 and higher plant in-service including Lake Side 2. Energy costs increased due to higher natural gas volumes including Lake Side 2 generation, higher average cost of coal, lower net deferrals of incurred net power costs, Utah mine disposition costs in 2014, higher average cost of purchased electricity and higher transmission expense, partially offset by lower purchased electricity volumes, lower coal volumes, lower average cost of natural gas and higher hydroelectric generation.

MidAmerican Funding

Operating revenue decreased $342 million for 2015 compared to 2014 due to lower regulated natural gas operating revenue of $335 million and lower nonregulated and other operating revenue of $27 million, partially offset by higher regulated electric operating revenue of $20 million. Regulated natural gas operating revenue decreased due to a lower average per-unit cost of gas sold of $290 million, which is offset in cost of sales, and 16.7% lower retail sales volumes primarily from warmer winter temperatures in 2015, partially offset by higher wholesale volumes. Nonregulated and other operating revenue decreased due to lower natural gas prices and volumes of $91 million, partially offset by higher electricity volumes and prices of $79 million. Regulated electric operating revenue increased due to higher retail revenue of $84 million, partially offset by lower wholesale and other revenue of $64 million. Retail revenue increased $70 million from higher electric rates primarily in Iowa, $16 million from non-weather-related customer load factors and $8 million from higher recoveries through bill riders and adjustment clauses, which is substantially offset in operating expense, partially offset by $10 million from the impact of warmer winter temperatures. The increase in Iowa electric rates reflects higher retail rates and changes in rate structure related to seasonal pricing that were effective with the implementation of final base rates in August 2014 and result in a greater differential between higher rates from June to September and lower rates in the remaining months. Electric retail customer load increased 1.2% as a result of strong industrial growth, net of the impact of temperatures compared to 2014. Electric wholesale and other revenue decreased primarily due to lower average wholesale prices of $62 million and lower wholesale volumes of $24 million, partially offset by higher transmission revenue of $25 million related to Multi-Value Projects, which are expected to increase as projects are constructed over the next two years.

Operating income increased $50 million for 2015 compared to 2014 due to higher regulated electric operating income of $66 million, partially offset by lower regulated natural gas operating income of $11 million and lower nonregulated and other operating income of $5 million. Regulated electric operating income increased due to lower energy costs of $99 million from a lower average cost of fuel for generation and lower purchased power costs, the higher retail rates and changes in rate structure related to seasonal pricing, the higher transmission revenue and lower fossil-fueled generation maintenance from planned major outages in 2014 of $10 million, partially offset by the lower wholesale revenue and higher depreciation and amortization of $56 million due to wind generation and other plant placed in-service. Regulated natural gas operating income decreased due to the lower retail sales volumes, partially offset by a one-time refund of $8 million to customers in 2014 of insurance recoveries related to environmental matters.

Operating revenue increased $349 million for 2014 compared to 2013 due to higher regulated natural gas operating revenue of $172 million, higher nonregulated and other operating revenue of $122 million and higher regulated electric operating revenue of $55 million. Regulated natural gas operating revenue increased due to an increase in recoveries through adjustment clauses from a higher average per-unit cost of gas sold of $165 million and higher retail sales volumes from colder winter temperatures in 2014, partially offset by lower wholesale volumes. Nonregulated and other operating revenue increased due to higher natural gas and electricity prices, higher electricity volumes and higher construction services, partially offset by lower natural gas volumes. Regulated electric operating revenue increased due to higher retail revenue of $61 million, partially offset by lower wholesale and other revenue of $6 million. Retail revenue was higher due to $49 million from higher electric rates in Iowa and $22 million from higher recoveries of demand-side management program costs, partially offset by $10 million from lower retail customer load for higher-priced, weather-sensitive customers. The increase in Iowa electric rates includes the increase in base rates implemented in August 2013 and, effective with the implementation of final base rates in August 2014, changes in rate structure related to seasonal pricing that result in higher rates from June to September and lower rates in the remaining months, and new adjustment clauses for recovery of retail energy production and transmission costs. Electric retail customer load increased 1.4% compared to 2013 as a result of strong industrial growth, partially offset by cooler summer temperatures in 2014. Electric wholesale revenue increased due to higher average prices of $17 million, partially offset by lower volumes of $16 million primarily from the higher retail energy requirements. Transmission revenue increased $6 million due to revenue from Multi-Value Projects. Other electric revenue decreased $13 million primarily from lower steam sales, partially due to the expiration of a contract, and lower sales of RECs.

Operating income increased $66 million for 2014 compared to 2013 primarily due to higher regulated electric operating income of $64 million. Regulated electric operating income increased due to the higher regulated electric operating revenue and $54 million of lower depreciation and amortization, partially offset by higher energy costs of $15 million, primarily due to higher fossil-fueled generation costs per unit and purchased power, and higher operating expense of $30 million. Operating expense increased primarily due to higher demand-side management program costs, higher transmission costs and higher property taxes. Depreciation and amortization decreased due to $79 million from the impact of depreciation rate changes, partially offset by additional plant in-service.

NV Energy

Operating revenue increased $110 million for 2015 compared to 2014 primarily due to higher electric operating revenue of $94 million and higher natural gas operating revenue of $12 million due to increased customer usage and higher rates. Electric operating revenue increased due to higher retail revenue of $82 million and higher wholesale and other revenue of $12 million primarily due to higher transmission revenue. Retail revenue was higher due to $45 million from higher customer growth, $31 million of higher energy efficiency rate revenue, which is offset in operating expense and $22 million of higher customer usage primarily due to the impacts of weather, partially offset by $18 million from lower retail rates as a result of deferred energy adjustment mechanisms. Electric retail customer load increased 2.4% compared to 2014.

Operating income increased $21 million for 2015 compared to 2014 due to higher electric margins of $76 million from the higher electric operating revenue, partially offset by higher energy costs of $18 million, higher depreciation and amortization of $31 million and higher operating expense of $30 million, primarily related to energy efficiency costs. Energy costs increased due to higher net deferred power costs of $247 million, partially offset by a lower average cost of fuel for generation of $228 million.

NV Energy was acquired on December 19, 2013. Operating revenue for 2014 totaled $3.2 billion and consisted of $3.1 billion of electric and $125 million of natural gas revenue. Operating income for 2014 totaled $791 million and consisted of $778 million of electric and $13 million of natural gas operating income. Operating revenue for 2013 reflects a one-time bill credit to retail customers of $20 million while operating loss for 2013 reflects the bill credit and $22 million related to charges under NV Energy's change in control policy.

Northern Powergrid

Operating revenue decreased $143 million for 2015 compared to 2014 due to the stronger United States dollar of $90 million, lower distribution revenue of $43 million and lower contracting and other revenue of $10 million. Distribution revenue decreased due to lower tariff rates of $99 million mainly reflecting the impact of the new price control period effective April 1, 2015 and lower units distributed of $6 million, partially offset by the recovery of the December 2013 customer rebate of $41 million and favorable movements in regulatory provisions of $21 million. Operating income decreased $81 million for 2015 compared to 2014 due to the stronger United States dollar of $47 million, the lower distribution revenue and higher pension costs of $9 million, partially offset by lower write-offs of hydrocarbon well exploration costs of $22 million.

Operating revenue increased $258 million for 2014 compared to 2013 due to higher distribution revenue of $183 million, the weaker United States dollar of $66 million and higher contracting revenue of $12 million. Distribution revenue increased due to higher tariff rates of $123 million, favorable movements in regulatory provisions in 2014 of $50 million and a rebate to customers in December 2013 totaling $45 million, partially offset by a 2.9% decrease in distributed units. Operating income increased $173 million for 2014 compared to 2013 largely due to the higher distribution revenue and the weaker United States dollar of $39 million, partially offset by higher distribution exit charges, write-offs of hydrocarbon well exploration costs of $21 million and higher depreciation and amortization.

BHE Pipeline Group

Operating revenue decreased $62 million for 2015 compared to 2014 due to lower gas sales of $68 million related to system and operational balancing activities, which are largely offset in cost of sales, partially offset by higher transportation revenues. Operating income increased $25 million for 2015 compared to 2014 due to the higher transportation revenues and lower operating expenses of $28 million primarily at Northern Natural Gas as a result of lower in-line inspection, hydrostatic testing and other maintenance project costs, partially offset by higher depreciation expense of $8 million.

Operating revenue increased $126 million for 2014 compared to 2013 due to higher operating revenue at Northern Natural Gas from both higher gas sales related to system and customer balancing activities of $77 million due to price spread volatility and extreme weather conditions, which are largely offset in cost of sales, and higher transportation revenue of $50 million due to higher rates and volumes. Operating income decreased $7 million due to higher operating expense of $49 million primarily at Northern Natural Gas as a result of higher in-line inspection, hydrostatic testing and other maintenance project costs and higher depreciation and amortization of $6 million, partially offset by the higher transportation revenue at Northern Natural Gas.

BHE Transmission

AltaLink was acquired on December 1, 2014, and its results are included in the consolidated results beginning as of that date. Operating revenue and operating income for 2015 from AltaLink were $592 million and $262 million, respectively, compared with $62 million and $31 million, respectively, for 2014. Operating income also increased for 2015 compared to 2014 due to lower acquisition and project development costs.

Operating revenue increased $62 million and operating income increased $31 million for 2014 compared to 2013 due to the acquisition of AltaLink in December 2014, partially offset by higher operating expense primarily related to higher acquisition and project development costs.

BHE Renewables

Operating revenue increased $105 million for 2015 compared to 2014 due to an increase of $160 million as additional solar and wind capacity was placed in-service and an increase from the acquisition of the remaining 50% interest in CE Generation in June 2014 of $55 million, partially offset by an $88 million decrease at CalEnergy Philippines due to the adoption of ASC 853 and lower wind generation at existing projects. Operating income decreased $59 million for 2015 compared to 2014 as the higher operating revenue was more than offset by higher operating expense of $101 million and higher depreciation and amortization of $64 million. Operating expense increased due to $69 million from the CE Generation acquisition, $22 million from additional solar and wind capacity placed in-service. Depreciation and amortization increased due to $52 million from additional solar and wind capacity placed in-service and $33 million from the CE Generation acquisition, partially offset by a $23 million decrease at CalEnergy Philippines due to the adoption of ASC 853.

Operating revenue increased $268 million for 2014 compared to 2013 due to an increase from the Topaz and Solar Star Projects of $165 million as additional solar capacity was placed in-service and an increase from the acquisition of the remaining 50% interest in CE Generation in June 2014 of $147 million, partially offset by an unfavorable movement in the valuation of the power purchase agreement derivative at Bishop Hill II of $26 million and lower variable fees earned in 2014 at the Casecnan Project of $22 million. Operating income increased $91 million for 2014 compared to 2013 due to the higher operating revenue, partially offset by higher operating costs and expenses of $127 million from the CE Generation acquisition and $50 million from additional solar capacity placed in-service.

HomeServices

Operating revenue increased $382 million for 2015 compared to 2014 due to a 12.0% increase in closed brokerage units and a 3% increase in average home sales prices. The increase in operating revenue was due to an increase from existing businesses totaling $225 million and an increase in acquired businesses totaling $157 million. The increase in existing businesses reflects an 8% increase in closed brokerage units and a 2% increase in average home sales prices. Operating income increased $59 million for 2015 compared to 2014 due to higher revenues, partially offset by higher costs, primarily commission expense, at existing businesses of $53 million and higher earnings at acquired businesses of $6 million.

Operating revenue increased $335 million for 2014 compared to 2013 due to an 8% increase in closed brokerage units and an 11% increase in average home sales prices. The increase in operating revenue was due to acquired businesses totaling $389 million, partially offset by a decrease in existing businesses totaling $54 million. The decrease in existing businesses reflects a 6% decrease in closed brokerage units and lower franchise revenue, partially offset by a 5% increase in average home sales prices. Operating income decreased $4 million for 2014 compared to 2013 as the higher earnings at acquired businesses totaling $22 million were more than offset by lower earnings at existing businesses of $26 million primarily due to the lower franchise business and brokerage businesses revenue and higher operating expense related to Berkshire Hathaway HomeServices rebranding activities at the franchise business.

BHE and Other

Operating loss increased $13 million for 2015 compared to 2014 due to higher other operating costs.

Operating revenue decreased $73 million for 2014 compared to 2013 due to higher intersegment eliminations related to the acquisition of NV Energy in December 2013.

Consolidated Other Income and Expense Items

Interest Expense

Interest expense for the years ended December 31 is summarized as follows (in millions):

	2015	2014	Change		2014	2013	Change	
Subsidiary debt	$ 1,392	$ 1,280	$ 112	9%	$ 1,280	$ 919	$ 361	39%
BHE senior debt and other	408	353	55	16	353	300	53	18
BHE junior subordinated debentures	104	78	26	33	78	3	75	*
Total interest expense	$ 1,904	$ 1,711	$ 193	11	$ 1,711	$ 1,222	$ 489	40

* Not meaningful

Interest expense on subsidiary debt increased $112 million for 2015 compared to 2014 due to $132 million from the acquisition of AltaLink in December 2014, partially offset by $11 million from the impact of the foreign currency exchange rate. Interest expense on subsidiary debt increased $361 million for 2014 compared to 2013 due to $283 million from the acquisition of NV Energy in December 2013, $14 million from the acquisition of AltaLink in December 2014, $10 million from the impact of the foreign currency exchange rate and $9 million from the acquisition of the remaining 50% interest in CE Generation in June 2014. Debt issuances at PacifiCorp, MidAmerican Funding, Northern Powergrid and BHE Renewables increased interest expense, partially offset by scheduled maturities and principal repayments.

Interest expense on BHE senior debt and other increased $55 million for 2015 compared to 2014 and $53 million for 2014 compared to 2013 due to the issuance of $2.0 billion of BHE senior debt in November 2013 and $1.5 billion of BHE senior debt in December 2014, partially offset by scheduled maturities of BHE senior debt totaling $250 million in 2014.

Interest expense on BHE junior subordinated debentures increased $26 million for 2015 compared to 2014 and $75 million for 2014 compared to 2013 from junior subordinated debentures issued to certain Berkshire Hathaway subsidiaries, partially offset by repayments at par value of BHE junior subordinated debentures due December 2043.

Capitalized Interest

Capitalized interest decreased $15 million for 2015 compared to 2014 as $25 million from AltaLink was more than offset by lower construction work-in-progress balances at BHE Renewables, MidAmerican Energy and PacifiCorp.

Capitalized interest increased $5 million for 2014 compared to 2013 due to higher construction work-in-progress balances related to additional wind-powered generation at MidAmerican Energy, the Jumbo Road Project, the Solar Star Projects and a full year of activity from NV Energy, partially offset by lower construction work-in-progress balances related to the Topaz Project and at PacifiCorp as Lake Side 2 was placed in-service in the second quarter of 2014.

Allowance for Equity Funds

Allowance for equity funds decreased $7 million for 2015 compared to 2014 as $29 million from AltaLink was more than offset by lower construction work-in-progress balances at MidAmerican Energy and PacifiCorp.

Allowance for equity funds increased $20 million for 2014 compared to 2013 due to higher construction work-in-progress balances related to additional wind-powered generation at MidAmerican Energy and a full year of activity from NV Energy, partially offset by lower construction work-in-progress balances at PacifiCorp as Lake Side 2 was placed in-service in the second quarter of 2014.

Interest and Dividend Income

Interest and dividend income increased $69 million for 2015 compared to 2014 primarily due to the recognition of interest income on the financial asset established as a result of the adoption of ASC 853 at CalEnergy Philippines.

Interest and dividend income increased $23 million for 2014 compared to 2013 primarily due to a full year of activity from NV Energy.

Other, Net

Other, net decreased $3 million for 2015 compared to 2014 due to gains from the acquisition of interests in equity method investments at HomeServices of $12 million in 2014, lower investment returns, lower income from a contract restructuring at Northern Natural Gas that expired in 2015 and the costs associated with the early redemption of the 6.676% Senior Notes at Kern River in 2015 of $5 million, partially offset by lower charitable contributions in 2015 and favorable movements in the Pinyon Pines interest rate swaps of $7 million.

Other, net decreased $9 million for 2014 compared to 2013 due to higher investment gains in 2013, an unfavorable movement on the Pinyon Pines interest rate swaps, benefits from a contract restructuring at Northern Natural Gas of $12 million in 2013 and higher charitable contributions in 2014, partially offset by a full year of activity from NV Energy of $16 million, contributions of $16 million to the NV Energy Foundation in 2013 and gains of $12 million from the acquisition of interests in equity method investments at HomeServices.

Income Tax Expense

Income tax expense decreased $139 million for 2015 compared to 2014 and the effective tax rate was 16% for 2015 and 23% for 2014. The effective tax rate decreased due to deferred income tax benefits of $39 million from a 2% reduction in the United Kingdom corporate income tax rate, favorable United States income taxes on foreign earnings of $36 million, favorable consolidated state income tax benefits of $35 million, favorable impacts of rate making of $34 million and higher production tax credits recognized of $33 million.

Income tax expense increased $459 million for 2014 compared to 2013 and the effective tax rate was 23% for 2014 and 7% for 2013. The effective tax rate increased due to deferred state income tax benefits in 2013 from the impact of the NV Energy acquisition of $89 million, a change in estimate in 2013 related to state apportionment of $72 million, deferred income tax benefits in 2013 of $54 million from reductions in the United Kingdom corporate income tax rate and higher pre-tax earnings, partially offset by the tax effect of the nondeductible impairment charges related to CE Generation of $21 million in 2013 and higher production tax credits of $11 million in 2014.

Income tax effect of foreign income includes, among other items, deferred income tax benefits of $39 million in 2015 and $54 million in 2013 related to the enactment of reductions in the United Kingdom corporate income tax rate. In November 2015 the corporate tax rate was reduced from 20% to 19% effective April 1, 2017, with a further reduction to 18% effective April 1, 2020. In July 2013 the corporate income tax rate was reduced from 23% to 21% effective April 1, 2014, with a further reduction to 20% effective April 1, 2015.

Federal renewable electricity production tax credits are earned as energy from qualifying wind-powered generating facilities is produced and sold based on a per kilowatt rate as prescribed pursuant to the applicable federal income tax law and are eligible for the credit for 10 years from the date the qualifying generating facilities are placed in-service. A credit of $0.023 per kilowatt hour was applied to 2015, 2014 and 2013 production, respectively, which resulted in $291 million, $258 million and $247 million, respectively, in recognized production tax credits.

Equity Income (Loss)

Equity income (loss) for the years ended December 31 is summarized as follows (in millions):

	2015	2014	Change		2014	2013	Change	
Equity income (loss):								
ETT	$ 81	$ 80	$ 1	1%	$ 80	$ 46	$ 34	74%
Agua Caliente	24	27	(3)	(11)	27	30	(3)	(10)
CE Generation	—	(8)	8	*	(8)	(126)	118	94
HomeServices	6	2	4	*	2	10	(8)	(80)
Other	4	8	(4)	(50)	8	5	3	60
Total equity income (loss)	$ 115	$ 109	$ 6	6	$ 109	$ (35)	$ 144	*

* Not meaningful

Equity income increased $6 million for 2015 compared to 2014 primarily due to the acquisition of the remaining interest in CE Generation on June 1, 2014 resulting in consolidation of the activity effective on this date.

Equity income (loss) increased $144 million for 2014 compared to 2013 due to a $116 million impairment charge related to CE Generation in 2013, the acquisition of the remaining interest in CE Generation on June 1, 2014 resulting in consolidation of the activity effective on this date and higher equity earnings at ETT from continued investment and additional plant placed in-service, partially offset by lower equity earnings at HomeServices due to lower refinancing activity and the acquisition of the remaining 50.1% interest of HomeServices Lending on October 1, 2014 resulting in consolidation of the activity effective on this date.

Net Income Attributable to Noncontrolling Interests

Net income attributable to noncontrolling interests increased $3 million for 2015 compared to 2014 due to higher earnings at HSF Affiliates. Net income attributable to noncontrolling interest decreased $13 million for 2014 compared to 2013 due to lower earnings at HSF Affiliates and PacifiCorp's redemption of all outstanding shares of its redeemable preferred stock totaling $40 million, plus accrued and unpaid dividends, in 2013.

Liquidity and Capital Resources

Each of BHE's direct and indirect subsidiaries is organized as a legal entity separate and apart from BHE and its other subsidiaries. It should not be assumed that the assets of any subsidiary will be available to satisfy BHE's obligations or the obligations of its other subsidiaries. However, unrestricted cash or other assets that are available for distribution may, subject to applicable law, regulatory commitments and the terms of financing and ring-fencing arrangements for such parties, be advanced, loaned, paid as dividends or otherwise distributed or contributed to BHE or affiliates thereof. The long-term debt of subsidiaries may include provisions that allow BHE's subsidiaries to redeem such debt in whole or in part at any time. These provisions generally include make-whole premiums. Refer to Note 17 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion regarding the limitation of distributions from BHE's subsidiaries.

As of December 31, 2015, the Company's total net liquidity was $6.1 billion as follows (in millions):

	BHE	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	AltaLink	Other	Total
Cash and cash equivalents	$ 23	$ 12	$ 103	$ 634	$ 85	$ 10	$ 241	$ 1,108
Credit facilities	2,000	1,200	609	650	221	813	928	6,421
Less:								
Short-term debt	(253)	(20)	—	—	—	(401)	(300)	(974)
Tax-exempt bond support and letters of credit	(51)	(160)	(195)	—	—	(9)	—	(415)
Net credit facilities	1,696	1,020	414	650	221	403	628	5,032
Total net liquidity	$ 1,719	$ 1,032	$ 517	$ 1,284	$ 306	$ 413	$ 869	$ 6,140
Credit facilities:								
Maturity dates	2017	2017, 2018	2016, 2018	2018	2020	2017, 2020	2016, 2018	

Refer to Notes 8 and 16 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for further discussion regarding the Company's credit facilities, letters of credit, equity commitments and other related items.

Operating Activities

Net cash flows from operating activities for the years ended December 31, 2015 and 2014 were $7.0 billion and $5.1 billion, respectively. Higher income tax receipts of $1.0 billion, improved operating results of $653 million, including $403 million from AltaLink, and other changes in working capital were partially offset by higher interest payments of $179 million. As of December 31, 2015, the Company had a current income tax receivable of $319 million.

Net cash flows from operating activities for the years ended December 31, 2014 and 2013 were $5.1 billion and $4.7 billion, respectively. The increase was primarily due to $1.7 billion of improved operating results, including $1.2 billion from NV Energy, partially offset by $512 million of higher interest payments, $470 million of lower income tax receipts and other changes in working capital. As of December 31, 2014, the Company had a current income tax receivable of $1.2 billion.

The timing of the Company's income tax cash flows from period to period can be significantly affected by the estimated federal income tax payment methods and assumptions for each payment date.

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. Production tax credits were extended for wind power and other forms of non-solar renewable energy projects that begin construction before the end of 2014. As a result of the Act, the Company's cash flows from operations benefited in 2015 due to bonus depreciation on qualifying assets placed in-service and for production tax credits earned on qualifying projects.

In December 2015, the Protecting Americans from Tax Hikes Act of 2015 ("PATH") was signed into law, extending bonus depreciation for qualifying property acquired and placed in-service before January 1, 2020 (bonus depreciation rates will be 50% in 2015-2017, 40% in 2018, and 30% in 2019), with an additional year for certain longer lived assets. Production tax credits were extended and phased-out for wind power and other forms of non-solar renewable energy projects that begin construction before the end of 2019. Production tax credits are maintained at full value through 2016, at 80% of value in 2017, at 60% of value in 2018, and 40% of value in 2019. Investment tax credits were extended and phased-down for solar projects that are under construction before the end of 2021 (investment tax credit rates are 30% through 2019, 26% in 2020 and 22% in 2021; they revert to the statutory rate of 10% thereafter). As a result of PATH, the Company's cash flows from operations are expected to benefit in 2016 and beyond due to bonus depreciation on qualifying assets placed in-service and production tax credits and investment tax credits earned on qualifying wind and solar projects, respectively.

Investing Activities

Net cash flows from investing activities for the years ended December 31, 2015 and 2014 were $(6.2) billion and $(9.4) billion, respectively. The change was primarily due to lower acquisitions totaling $164 million in 2015 compared to $3.0 billion in 2014 ($2.7 billion for AltaLink) and lower capital expenditures of $680 million, partially offset by changes in restricted cash and investments of $201 million and higher equity method investments of $165 million. Refer to "Future Uses of Cash" for further discussion of capital expenditures.

Net cash flows from investing activities for the years ended December 31, 2014 and 2013 were $(9.4) billion and $(10.2) billion, respectively. Acquisitions in 2014 included the $2.7 billion AltaLink acquisition and other acquisitions totaling $243 million primarily for the remaining 50% interest in CE Generation, the Jumbo Road Project and real estate brokerage and mortgage businesses. Acquisitions in 2013 included the $5.6 billion NV Energy acquisition and other acquisitions totaling $240 million for real estate brokerage and mortgage businesses. Additionally, higher capital expenditures of $2.2 billion, including NV Energy, were partially offset by changes in restricted cash and investments of $407 million and lower equity method investments of $56 million.

Financing Activities

Net cash flows from financing activities for the year ended December 31, 2015 were $(255) million. Sources of cash totaled $2.5 billion and consisted of proceeds from subsidiary debt. Uses of cash totaled $2.7 billion and consisted mainly of $1.4 billion for repayments of subsidiary debt, repayments of BHE subordinated debt totaling $850 million and net repayments of short-term debt of $421 million.

In December 2015, Northern Powergrid (Northeast) Limited issued £120 million of notes at 2.564% due 2027 under its finance contract with the European Investment Bank. The net proceeds were used for general corporate purposes, including the repayment of short-term debt.

In December 2015, Northern Powergrid (Yorkshire) plc issued £130 million of notes at 2.564% due 2027 under its finance contract with the European Investment Bank. The net proceeds were used for general corporate purposes, including the repayment of short-term debt.

In October 2015, MidAmerican Energy issued $200 million of its 3.50% First Mortgage Bonds due October 2024 and $450 million of its 4.25% First Mortgage Bonds due May 2046. The net proceeds were used for the repayment of $426 million of long-term debt that matured December 31, 2015, and for general corporate purposes.

In September 2015, TX Jumbo Road Wind, LLC issued a $230 million Term Loan due September 2025. The Term Loan has an underlying variable interest rate based on LIBOR plus a fixed credit spread with a one-time increase during the term of the loan. The Company has entered into interest rate swaps that fix the underlying interest rate on 100% of the outstanding debt.

In June 2015, PacifiCorp issued $250 million of its 3.35% First Mortgage Bonds due July 2025. The net proceeds were used to fund capital expenditures and for general corporate purposes, including retirement of short-term debt.

In June 2015, ALP issued C$350 million of its 4.09% Series 2015-1 Medium-Term Notes due June 2045. The net proceeds were used to repay short-term debt.

In April 2015, Northern Powergrid (Yorkshire) plc issued £150 million of its 2.50% Bonds due April 2025. The net proceeds were used for general corporate purposes, including the repayment of short-term debt.

In March 2015, Solar Star Funding, LLC issued $325 million of its 3.95% Series B Senior Secured Notes. The principal of the notes amortizes beginning June 2016 with a final maturity in June 2035. The net proceeds were used to fund the repayment or reimbursement of amounts provided by BHE for the costs related to the development, construction and financing of the Solar Star Projects.

In March 2015, AltaLink Investments, L.P. issued C$200 million of its 2.244% Series 15-1 Senior Bonds due March 2022. The net proceeds were used to repay short-term debt, provide equity to ALP and for general corporate purposes.

Net cash flows from financing activities for the year ended December 31, 2014 were $3.7 billion. Sources of cash totaled $5.3 billion and consisted of proceeds from BHE junior subordinated debentures totaling $1.5 billion, proceeds from subsidiary debt totaling $1.3 billion, proceeds from BHE senior debt totaling $1.5 billion and net proceeds from short-term debt totaling $1.1 billion. Uses of cash totaled $1.6 billion and consisted mainly of $1.0 billion for repayments of subsidiary debt and repayments of BHE senior and subordinated debt totaling $550 million.

On December 1, 2014, BHE completed its acquisition of AltaLink. Following completion of the acquisition, AltaLink became an indirect wholly owned subsidiary of BHE. Under the terms of the Share Purchase Agreement, dated May 1, 2014, among BHE and SNC-Lavalin Group Inc., BHE paid C$3.1 billion (US$2.7 billion) in cash to SNC-Lavalin Group Inc. for 100% of the equity interests of AltaLink. BHE funded the total purchase price with $1.5 billion of junior subordinated debentures issued and sold to subsidiaries of Berkshire Hathaway, $1.0 billion borrowed under its commercial paper program and cash on hand. On December 4, 2014, BHE issued $350 million of 2.40% Senior Notes due 2020, $400 million of 3.50% Senior Notes due 2025 and $750 million of 4.50% Senior Notes due 2045 and used the proceeds to repay commercial paper borrowings.

Net cash flows from financing activities for the year ended December 31, 2013 were $5.9 billion. Sources of cash totaled $8.1 billion and consisted of proceeds from BHE junior subordinated debentures totaling $2.6 billion, proceeds from subsidiary debt totaling $2.5 billion, proceeds from BHE senior debt totaling $2.0 billion and proceeds from the issuance of common stock of $1.0 billion. Uses of cash totaled $2.2 billion and consisted mainly of $1.2 billion for repayments of subsidiary debt and net repayments of short-term debt totaling $849 million.

BHE funded the NV Energy acquisition by issuing $1.0 billion of common stock on December 19, 2013, issuing $2.6 billion of junior subordinated debentures to certain Berkshire Hathaway subsidiaries on December 19, 2013, and using $2.0 billion of cash, including certain proceeds from BHE’s $2.0 billion senior debt issuance on November 8, 2013.

The Company 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 the Company may be reissued or resold by the Company from time to time and will depend on prevailing market conditions, the Company's liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Future Uses of Cash

The Company 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, the issuance of equity and other sources. These sources are expected to provide funds required for current operations, capital expenditures, acquisitions, investments, debt retirements and other capital requirements. The availability and terms under which BHE and each subsidiary has access to external financing depends on a variety of factors, including its credit ratings, investors' judgment of risk and conditions in the overall capital markets, including the condition of the utility industry and project finance markets, among other items.

Capital Expenditures

The Company 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. Expenditures for certain assets may ultimately include acquisitions of existing assets.

The Company's historical and forecast capital expenditures, each of which exclude amounts for non-cash equity AFUDC and other non-cash items, by reportable segment for the years ended December 31 are as follows (in millions):

	Historical			Forecast		
	2013	2014	2015	2016	2017	2018
PacifiCorp	$ 1,065	$ 1,066	$ 916	$ 795	$ 780	$ 846
MidAmerican Funding	1,027	1,527	1,448	1,204	602	401
NV Energy	—	558	571	435	403	340
Northern Powergrid	675	675	674	640	564	533
BHE Pipeline Group	177	257	240	236	312	132
BHE Transmission	—	222	966	514	562	603
BHE Renewables	1,329	2,221	1,034	561	74	65
HomeServices	21	17	16	25	17	17
BHE and Other	13	12	10	24	24	14
Total	$ 4,307	$ 6,555	$ 5,875	$ 4,434	$ 3,338	$ 2,951

	Historical			Forecast		
	2013	2014	2015	2016	2017	2018
Solar generation	$ 1,323	$ 1,896	$ 786	$ 17	$ 8	$ —
Wind generation	404	1,052	1,177	1,293	—	—
Electric transmission	341	547	936	505	539	509
Environmental	228	258	134	78	130	108
Other developmental projects	156	178	63	34	247	20
Electric distribution and other operating	1,855	2,624	2,779	2,507	2,414	2,314
Total	$ 4,307	$ 6,555	$ 5,875	$ 4,434	$ 3,338	$ 2,951

The Company's historical and forecast capital expenditures consisted mainly of the following:

- Solar generation includes the following:
    - Construction of the Topaz Project totaling $49 million for 2015, $814 million for 2014 and $652 million for 2013. Final completion under the engineering, procurement and construction agreement occurred February 28, 2015, and project completion was achieved under the financing documents on March 30, 2015.
    - Construction of the Solar Star Projects totaling $689 million for 2015, $1.1 billion for 2014 and $671 million for 2013. Both projects declared July 1, 2015 as the commercial operation date in accordance with the power purchase agreements. Final completion under the engineering, procurement and construction agreements occurred November 30, 2015 and project completion was achieved under the financing documents on December 15, 2015.

- Wind generation includes the following:
    - Construction of wind-powered generating facilities at MidAmerican Energy totaling $931 million for 2015, $767 million for 2014 and $401 million for 2013. MidAmerican Energy placed in-service 608 MW (nominal ratings) during 2015, 511 MW (nominal ratings) during 2014 and 44 MW (nominal ratings) during 2013. MidAmerican Energy is constructing an additional 551 MW (nominal ratings) approved by the IUB in August 2015 that are expected to be placed in-service in 2016. In April 2015, MidAmerican Energy filed with the IUB an application for ratemaking principles related to the construction of up to 552 MW (nominal ratings) of additional wind-powered generating facilities expected to be placed in-service by the end of 2016. In June 2015, MidAmerican Energy and the Iowa Office of Consumer Advocate ("OCA") entered into a settlement agreement relating to the proposal. The settlement agreement established a cost cap of $903 million, including AFUDC, and provides for a fixed rate of return on equity of 11.35% over the proposed 30-year useful lives of those facilities in any future Iowa rate proceeding. In August 2015, the IUB approved the settlement agreement except for a reduction of the cost cap to $889 million, including AFUDC, to which MidAmerican Energy and the OCA agreed. The cost cap ensures that as long as total costs are below the cap, the investment will be deemed prudent in any future Iowa rate proceeding. MidAmerican Energy expects all of these wind-powered generating facilities to qualify for federal production tax credits. MidAmerican Energy continues to evaluate additional cost effective wind-powered generation.
    - Construction of wind-powered generating facilities at BHE Renewables totaling $246 million for 2015, $286 million for 2014 and $3 million for 2013. The Jumbo Road Project with a total capacity of 300 MW achieved commercial operation in April 2015. In addition, BHE Renewables acquired in 2015 for cash consideration totaling $111 million certain assets that will facilitate the development of up to 472 MW of wind-powered generating facilities in Nebraska and Kansas. BHE Renewables anticipates costs for wind-powered generating facilities will total $461 million in 2016. BHE Renewables expects all of these wind-powered generating facilities to qualify for federal production tax credits.
- Electric transmission includes investments for ALP's transmission system including directly assigned projects from the AESO, PacifiCorp's costs primarily associated with main grid reinforcement and the Energy Gateway Transmission Expansion Program and MidAmerican Energy's MVPs approved by the MISO for the construction of 245 miles of 345 kV transmission line located in Iowa and Illinois.
- Environmental includes the installation of new or the replacement of existing emissions control equipment at certain generating facilities at the Utilities, including installation or upgrade of selective catalytic reduction control systems and low nitrogen oxide burners to reduce nitrogen oxides, particulate matter control systems, sulfur dioxide emissions control systems and mercury emissions control systems, as well as expenditures for the management of coal combustion residuals.
- Electric distribution and other operating includes ongoing distribution systems infrastructure needed at the Utilities and Northern Powergrid and investments in routine expenditures for transmission, generation and other infrastructure needed to serve existing and expected demand.

Contractual Obligations

The Company has contractual cash obligations that may affect its consolidated financial condition. The following table summarizes the Company's material contractual cash obligations as of December 31, 2015 (in millions):

	Payments Due By Periods				
	2016	2017-2018	2019-2020	2021 and After	Total
BHE senior debt	$ —	$ 1,400	$ 350	$ 6,125	$ 7,875
BHE junior subordinated debentures	—	—	—	2,944	2,944
Subsidiary debt	1,148	3,105	3,309	19,752	27,314
Interest payments on long-term debt(1)	1,855	3,584	3,100	21,342	29,881
Short-term debt	974	—	—	—	974
Fuel, capacity and transmission contract commitments(1)	2,214	3,105	2,358	9,494	17,171
Construction commitments(1)	1,544	36	6	5	1,591
Operating leases and easements(1)	143	213	143	1,007	1,506
Other(1)	219	508	412	988	2,127
Total contractual cash obligations	$ 8,097	$ 11,951	$ 9,678	$ 61,657	$ 91,383

(1) Not reflected on the Consolidated Balance Sheets.

The Company has other types of commitments that arise primarily from unused lines of credit, letters of credit or relate to construction and other development costs (Liquidity and Capital Resources included within this Item 7 and Note 8), uncertain tax positions (Note 11) and asset retirement obligations (Note 13), which have not been included in the above table because the amount and timing of the cash payments are not certain. Refer, where applicable, to the respective referenced note in Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Additionally, the Company has invested in projects sponsored by third parties, commonly referred to as tax equity investments. Under the terms of these tax equity investments, the Company has entered into equity capital contribution agreements with the project sponsors that require contributions. The Company has made contributions of approximately $170 million in 2015 and expects to contribute $563 million in 2016 pursuant to these equity capital contribution agreements as the various projects achieve commercial operation. Once a project achieves commercial operation, the Company will enter into a partnership agreement with the project sponsor that directs and allocates the operating profits and tax benefits generated by the project.

Regulatory Matters

The Company is subject to comprehensive regulation. Refer to the discussion contained in Item 1 of this Form 10-K for further discussion regarding the Company's general regulatory framework and current regulatory matters.

Quad Cities Station Operating Status

Exelon Generation, the operator of Quad Cities Station of which MidAmerican Energy has a 25% ownership interest, has stated that it is evaluating the economic value of several of its nuclear generating facilities, including Quad Cities Station. Included in such evaluation is the possibility of early retirement of Quad Cities Station prior to the expiration of its operating license in 2032. Exelon Generation has not provided MidAmerican Energy with notice of any decision to retire Quad Cities Station. MidAmerican Energy has expressed to Exelon Generation its desire for the continued operation of the facility through the end of its operating license.

A decision by Exelon Generation to retire Quad Cities Station before the end of its operating license would require an evaluation of the carrying value and classification of assets and liabilities related to Quad Cities Station on MidAmerican Energy's balance sheets.

Environmental Laws and Regulations

The Company is subject to federal, state, local and foreign 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 its 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, local and international 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 the Company is unable to predict the impact of the changing laws and regulations on its operations and consolidated financial results. The Company believes it is in material compliance with all applicable laws and regulations.

Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for further discussion regarding environmental laws and regulations and "Liquidity and Capital Resources" for the Company's forecast environmental-related capital expenditures.

Collateral and Contingent Features

Debt of BHE and debt and preferred securities of certain of its subsidiaries are rated by credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of the rated company'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.

BHE and its subsidiaries have 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. The Company'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.

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," or in some cases terminate the contract, in the event of a material adverse change in creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2015, the applicable entities' credit ratings from the three recognized credit rating agencies were investment grade. If all credit-risk-related contingent features or adequate assurance provisions for these agreements had been triggered as of December 31, 2015, the Company would have been required to post $615 million of additional collateral. The Company'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 14 of Notes to Consolidated Financial Statements for a discussion of the Company's collateral requirements specific to its derivative contracts.

The Company 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 the Company. 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. The Company qualifies or believes it will qualify for many of these exemptions. The Company 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 the Company or could have impacts to energy and other markets in general that could have an impact on the Company's consolidated financial results.

Inflation

Historically, overall inflation and changing prices in the economies where BHE's subsidiaries operate have not had a significant impact on the Company's consolidated financial results. In the United States and Canada, the Regulated Businesses operate under cost-of-service based rate structures administered by various state and provincial commissions and the FERC. Under these rate structures, the Regulated Businesses are allowed to include prudent costs in their rates, including the impact of inflation. The price control formula used by the Northern Powergrid Distribution Companies incorporates the rate of inflation in determining rates charged to customers. BHE's subsidiaries attempt to minimize the potential impact of inflation on their operations through the use of fuel, energy and other cost adjustment clauses and bill riders, 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

The Company has certain investments that are accounted for under the equity method in accordance with accounting principles generally accepted in the United States of America ("GAAP"). Accordingly, an amount is recorded on the Company's Consolidated Balance Sheets as an equity investment and is increased or decreased for the Company's pro-rata share of earnings or losses, respectively, less any dividends from such investments. Certain equity investments are presented on the Consolidated Balance Sheets net of investment tax credits.

As of December 31, 2015, the Company's investments that are accounted for under the equity method had short- and long-term debt of $2.5 billion, unused revolving credit facilities of $225 million and letters of credit outstanding of $88 million. As of December 31, 2015, the Company's pro-rata share of such short- and long-term debt was $1.2 billion, unused revolving credit facilities was $81 million and outstanding letters of credit was $43 million. The entire amount of the Company's pro-rata share of the outstanding short- and long-term debt and unused revolving credit facilities is non-recourse to the Company. The entire amount of the Company's pro-rata share of the outstanding letters of credit is recourse to the Company. Although the Company is generally not required to support debt service obligations of its equity investees, default with respect to this non-recourse short- and long-term debt could result in a loss of invested equity.

New Accounting Pronouncements

For a discussion of new accounting pronouncements affecting the Company, 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 the Company's methods, judgments and assumptions used in the preparation of the Consolidated Financial Statements and should be read in conjunction with the Company'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

The Regulated Businesses prepare their financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, the Regulated Businesses defer the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated 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 regulated rates occur.

The Company continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future regulated 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 the Regulated Businesses' ability to recover their costs. The Company believes the application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in future regulated rates. The evaluation reflects the current political and regulatory climate at both the federal, state and provincial levels. If it becomes no longer probable that the deferred costs or income will be included in future regulated rates, the related regulatory assets and liabilities will be recognized in net income, returned to customers or re-established as accumulated other comprehensive income (loss) ("AOCI"). Total regulatory assets were $4.3 billion and total regulatory liabilities were $3.0 billion as of December 31, 2015. Refer to Note 6 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding the Regulated Businesses' regulatory assets and liabilities.

Derivatives

The Company is exposed to the impact of market fluctuations in commodity prices, interest rates and foreign currency exchange rates. The Company is principally exposed to electricity, natural gas, coal and fuel oil commodity price risk primarily through BHE's ownership of the Utilities as they have an obligation to serve retail customer load in their regulated service territories. The Company also provides nonregulated retail electricity and natural gas services in competitive markets. The Utilities' 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, wholesale electricity that is purchased and sold, and natural gas supply for retail customers. 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, future debt issuances and mortgage commitments. Additionally, BHE is exposed to foreign currency exchange rate risk from its business operations and investments in Great Britain and Canada. Each of BHE's business platforms has established a risk management process that is designed to identify, assess, manage, mitigate, monitor and report each of the various types of risk involved in its business. The Company employs a number of different derivative contracts, which may include forwards, futures, options, swaps and other agreements, to manage its commodity price, interest rate, and foreign currency exchange rate risk. The Company 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, the Company may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, forward sale commitments, or mortgage interest rate lock commitments, to mitigate the Company's exposure to interest rate risk. The Company does not hedge all of its commodity price, interest rate and foreign currency exchange rate risks, thereby exposing the unhedged portion to changes in market prices. Refer to Notes 14 and 15 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding the Company'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 GAAP. When available, the fair value of derivative contracts is estimated using unadjusted quoted prices for identical contracts in the market in which the Company transacts. When quoted prices for identical contracts are not available, the Company uses forward price curves. Forward price curves represent the Company's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. The Company bases its forward price curves upon market price quotations, when available, or internally developed and commercial models, with internal and external fundamental data inputs. Market price quotations are obtained from independent brokers, exchanges, direct communication with market participants and actual transactions executed by the Company. Market price quotations are generally readily obtainable for the applicable term of the Company's outstanding derivative contracts; therefore, the Company's forward price curves reflect observable market quotes. As of December 31, 2015, the Company had a net derivative liability of $288 million related to contracts valued using either quoted prices or forward price curves based upon observable market quotes. Market price quotations for certain electricity and natural gas trading hubs are not as readily obtainable due to the length of the contract. Given that limited market data exists for these contracts, as well as for those contracts that are not actively traded, the Company 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 important because any changes in assumptions could have a significant impact on the estimated fair value of the contracts. As of December 31, 2015, the Company had a net derivative asset of $51 million related to contracts where the Company uses internal models with significant unobservable inputs.

Classification and Recognition Methodology

The majority of the Company's commodity derivative contracts are probable of inclusion in the rates of its rate-regulated subsidiaries, and changes in the estimated fair value of derivative contracts are generally recorded as net regulatory assets or liabilities. Accordingly, amounts are generally not recognized in earnings until the contracts are settled and the forecasted transaction has occurred. As of December 31, 2015, the Company had $250 million recorded as net regulatory assets related to derivative contracts on the Consolidated Balance Sheets.

Impairment of Goodwill and Long-Lived Assets

The Company's Consolidated Balance Sheet as of December 31, 2015 includes goodwill of acquired businesses of $9.1 billion. The Company evaluates goodwill for impairment at least annually and completed its annual review as of October 31. Additionally, no indicators of impairment were identified as of December 31, 2015. Significant judgment is required in estimating the fair value of the reporting unit and performing goodwill impairment tests. The Company uses a variety of methods to estimate a reporting unit's fair value, principally discounted projected future net cash flows. Key assumptions used include, but are not limited to, the use of estimated future cash flows; multiples of earnings; and an appropriate discount rate. Estimated future cash flows are impacted by, among other factors, growth rates, changes in regulations and rates, ability to renew contracts and estimates of future commodity prices. In estimating future cash flows, the Company incorporates current market information, as well as historical factors. Refer to Note 21 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding the Company's goodwill.

The Company evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As substantially all property, plant and equipment was used in regulated businesses as of December 31, 2015, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

The estimate of cash flows arising from the future use of the asset that are used in the impairment analysis requires judgment regarding what the Company would expect to recover from the future use of the asset. Changes in judgment that could significantly alter the calculation of the fair value or the recoverable amount of the asset may result from significant changes in the regulatory environment, the business climate, management's plans, legal factors, market price of the asset, the use of the asset or the physical condition of the asset, future market prices, load growth, competition and many other factors over the life of the asset. Any resulting impairment loss is highly dependent on the underlying assumptions and could significantly affect the Company's results of operations.

Pension and Other Postretirement Benefits

Certain of the Company's subsidiaries sponsor defined benefit pension and other postretirement benefit plans that cover the majority of employees. The Company recognizes the funded status of the 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, 2015, the Company recognized a net liability totaling $389 million for the funded status of the defined benefit pension and other postretirement benefit plans. As of December 31, 2015, amounts not yet recognized as a component of net periodic benefit cost that were included in net regulatory assets totaled $765 million and in AOCI totaled $605 million.

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. The Company 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 12 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for disclosures about the 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, 2015.

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

The Company 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 5.00% by 2025, at which point the rate of increase is assumed to remain constant. Refer to Note 12 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 (dollars in millions):

	Domestic Plans					
	Pension Plans		Other Postretirement Benefit Plans		United Kingdom Pension Plan	
	+0.5%	-0.5%	+0.5%	-0.5%	+0.5%	-0.5%
Effect on December 31, 2015						
Benefit Obligations:						
Discount rate	$ (146)	$ 162	$ (31)	$ 34	$ (172)	$ 197
Effect on 2015 Periodic Cost:						
Discount rate	$ (7)	$ 10	$ —	$ 1	$ (17)	$ 17
Expected rate of return on plan assets	(12)	12	(4)	4	(11)	11

A variety of factors affect the funded status of the plans, including asset returns, discount rates, mortality assumptions, plan changes and the Company's funding policy for each plan.

Income Taxes

In determining the Company's income taxes, management is required to interpret complex income tax laws and regulations, which includes consideration of regulatory implications imposed by the Company's various regulatory jurisdictions. The Company's income tax returns are subject to continuous examinations by federal, state, local and foreign 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. The Company 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 the Company's federal, state, local and foreign income tax examinations is uncertain, the Company 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 the Company's consolidated financial results. Refer to Note 11 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding the Company's income taxes.

The Utilities are required to pass income tax benefits related to certain property-related basis differences and other various differences on to their customers in certain state jurisdictions. As of December 31, 2015, these amounts were recognized as a regulatory asset of $1.5 billion and a regulatory liability of $29 million and will be included in regulated rates when the temporary differences reverse.

The Company has not established deferred income taxes on the undistributed foreign earnings of Northern Powergrid or AltaLink or the related currency translation adjustment that have been determined by management to be reinvested indefinitely. The cumulative undistributed foreign earnings were approximately $3.0 billion as of December 31, 2015. The Company periodically evaluates its capital requirements. If circumstances change in the future and a portion of Northern Powergrid's or AltaLink's undistributed earnings were repatriated, the dividends would be subject to taxation in the United States. However, any United States income tax liability would be offset, in part, by available United States income tax credits with respect to corporate income taxes previously paid in the United Kingdom and Canada. Because of the availability of foreign income tax credits, it is not practicable to determine the United States income tax liability that would be recognized if such cumulative earnings were not reinvested indefinitely. The Company has established deferred income taxes on all other undistributed foreign earnings. If opportunities become available to repatriate any available cash without triggering incremental United States income tax expense, the Company may distribute certain foreign earnings of Northern Powergrid and AltaLink.

Revenue Recognition - Unbilled Revenue

Revenue from energy business customers is recognized as electricity or natural gas is delivered or services are provided. The determination of customer billings is based on a systematic reading of meters, fixed reservation charges based on contractual quantities and rates or, in the case of the Great Britain distribution businesses, when information is received from the national settlement system. 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 $660 million as of December 31, 2015. 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

The Company's Consolidated Balance Sheets include assets and liabilities with fair values that are subject to market risks. The Company's significant market risks are primarily associated with commodity prices, interest rates, equity prices, foreign currency exchange rates and the extension of credit to counterparties with which the Company transacts. The following discussion addresses the significant market risks associated with the Company's business activities. Each of the Company's business platforms has established guidelines for credit risk management. Refer to Notes 2 and 14 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding the Company's contracts accounted for as derivatives.

Commodity Price Risk

The Company is principally exposed to electricity, natural gas, coal and fuel oil commodity price risk primarily through BHE's ownership of the Utilities as they have an obligation to serve retail customer load in their regulated service territories. The Company also provides nonregulated retail electricity and natural gas services in competitive markets. The Utilities' 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, wholesale electricity that is purchased and sold, and natural gas supply for retail customers. 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. The Company does not engage in a material amount of proprietary trading activities. To mitigate a portion of its commodity price risk, the Company uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. The Company does not hedge all of its commodity price risk, thereby exposing the unhedged portion to changes in market prices. The Company's exposure to commodity price risk is generally limited by its ability to include commodity costs in regulated rates, which is subject to regulatory lag that occurs between the time the costs are incurred and when the costs are included in regulated rates, as well as the impact of any customer sharing resulting from cost adjustment mechanisms.

The table that follows summarizes the Company's price risk on commodity contracts accounted for as derivatives, excluding collateral netting of $103 million and $75 million as of December 31, 2015 and 2014, respectively, and shows the effects of a hypothetical 10% increase and 10% decrease in forward market prices with the contracted or expected volumes. 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, 2015:			
Not designated as hedging contracts	$ (186)	$ (148)	$ (224)
Designated as hedging contracts	(47)	(4)	(89)
Total commodity derivative contracts	$ (233)	$ (152)	$ (313)
As of December 31, 2014:			
Not designated as hedging contracts	$ (156)	$ (120)	$ (191)
Designated as hedging contracts	(36)	9	(81)
Total commodity derivative contracts	$ (192)	$ (111)	$ (272)

Certain of the Company's commodity derivative contracts not designated as hedging contracts are recoverable from customers in regulated rates and, therefore, net unrealized gains and losses associated with interim price movements on commodity derivative contracts do not expose the Company to earnings volatility. As of December 31, 2015 and 2014, a net regulatory asset of $250 million and $223 million, respectively, was recorded related to the net derivative liability of $186 million and $156 million, respectively. The difference between the net regulatory asset and the net derivative liability relates primarily to a power purchase agreement derivative at BHE Renewables. For the Company's commodity derivative contracts designated as hedging contracts, net unrealized gains and losses associated with interim price movements on commodity derivative contracts, to the extent the hedge is considered effective, generally do not expose the Company to earnings volatility. The settled cost of these commodity derivative contracts is generally included in regulated rates. Consolidated financial results would be negatively impacted if the costs of wholesale electricity, natural gas or fuel are higher than what is included in regulated rates, including the impacts of adjustment mechanisms.

Interest Rate Risk

The Company is exposed to interest rate risk on its outstanding variable-rate short- and long-term debt and future debt issuances. The Company 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, the Company's fixed-rate long-term debt does not expose the Company 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 the Company were to reacquire all or a portion of these instruments prior to their maturity. The nature and amount of the Company'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 8, 9, 10, and 15 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional discussion of the Company's short- and long-term debt.

As of December 31, 2015 and 2014, the Company had short- and long-term variable-rate obligations totaling $5.5 billion and $6.7 billion, respectively, that expose the Company to the risk of increased interest expense in the event of increases in short-term interest rates. If variable interest rates were to increase by 10% from December 31 levels, it would not have a material effect on the Company's consolidated annual interest expense. The carrying value of the variable-rate obligations approximates fair value as of December 31, 2015 and 2014.

The Company may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, forward sale commitments, or mortgage interest rate lock commitments, to mitigate the Company's exposure to interest rate risk. Changes in fair value of agreements designated as cash flow hedges are reported in accumulated other comprehensive income to the extent the hedge is effective until the forecasted transaction occurs. Changes in fair value of agreements not designated as hedging contracts are recognized in earnings. As of December 31, 2015 and 2014, the Company had variable-to-fixed interest rate swaps for the notional amount of $653 million and $443 million, respectively, to protect the Company against an increase in interest rates. Additionally, as of December 31, 2015 and 2014, the Company had mortgage sale commitments, net for the notional amount of $312 million and $264 million, respectively, to protect the Company against an increase in interest rates. As of December 31, 2015 and 2014, the fair value of the Company's interest rate derivative contracts was a net derivative liability of $4 million and $5 million, respectively. A hypothetical 20 basis point increase and a 20 basis point decrease in the interest rate would not have a material impact on the Company.

Equity Price Risk

Market prices for equity securities are subject to fluctuation and consequently the amount realized in the subsequent sale of an investment may significantly differ from the reported market value. Fluctuation in the market price of a security may result from perceived changes in the underlying economic characteristics of the investee, the relative price of alternative investments and general market conditions.

As of December 31, 2015 and 2014, the Company's investment in BYD Company Limited common stock represented approximately 76% and 70%, respectively, of the total fair value of the Company's equity securities. The majority of the Company's remaining equity securities related to certain trust funds in which realized and unrealized gains and losses are recorded as a net regulatory liability since the Company expects to recover costs for these activities through regulated rates. The following table summarizes the Company's investment in BYD Company Limited as of December 31, 2015 and 2014 and the effects of a hypothetical 30% increase and a 30% decrease in market price as of those dates. The selected hypothetical change does not reflect what could be considered the best or worst case scenarios (dollars in millions).

	Fair Value	Hypothetical Price Change	Estimated Fair Value after Hypothetical Change in Prices	Hypothetical Percentage Increase (Decrease) in BHE Shareholders' Equity
As of December 31, 2015	$ 1,238	30% increase	$ 1,609	1%
		30% decrease	867	(1)
As of December 31, 2014	$ 881	30% increase	$ 1,145	1%
		30% decrease	617	(1)

Foreign Currency Exchange Rate Risk

BHE's business operations and investments outside of the United States increase its risk related to fluctuations in foreign currency exchange rates primarily in relation to the British pound and the Canadian dollar. BHE's reporting currency is the United States dollar, and the value of the assets and liabilities, earnings, cash flows and potential distributions from BHE's foreign operations changes with the fluctuations of the currency in which they transact.

Northern Powergrid's functional currency is the British pound. As of December 31, 2015, a 10% devaluation in the British pound to the United States dollar would result in the Company's Consolidated Balance Sheet being negatively impacted by a $386 million cumulative translation adjustment in AOCI. A 10% devaluation in the average currency exchange rate would have resulted in lower reported earnings for Northern Powergrid of $42 million in 2015.

AltaLink's functional currency is the Canadian dollar. As of December 31, 2015, a 10% devaluation in the Canadian dollar to the United States dollar would result in the Company's Consolidated Balance Sheet being negatively impacted by a $251 million cumulative translation adjustment in AOCI. A 10% devaluation in the average currency exchange rate would have resulted in lower reported earnings for AltaLink of $13 million in 2015.

Credit Risk

Domestic Regulated Operations

The Utilities are 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 the Utilities' counterparties have similar economic, industry or other characteristics and due to direct or indirect relationships among the counterparties. Before entering into a transaction, the Utilities analyze the financial condition of each significant wholesale counterparty, establish limits on the amount of unsecured credit to be extended to each counterparty and evaluate the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, the Utilities enter into netting and collateral arrangements that may include margining and cross-product netting agreements and obtain third-party guarantees, letters of credit and cash deposits. If required, the Utilities exercise rights under these arrangements, including calling on the counterparty's credit support arrangement.

As of December 31, 2015, PacifiCorp's aggregate credit exposure from wholesale activities totaled $124 million, based on settlement and mark-to-market exposures, net of collateral. As of December 31, 2015, $123 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, 2015, two counterparties comprised $94 million, or 75%, 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, 2015.

Substantially all of MidAmerican Energy's electric wholesale sales revenue results from participation in regional transmission organizations ("RTOs"), including the MISO and the PJM. MidAmerican Energy's share of historical losses from defaults by other RTO market participants has not been material. Additionally, as of December 31, 2015, MidAmerican Energy's aggregate direct credit exposure from electric wholesale marketing counterparties was not material.

As of December 31, 2015, NV Energy's aggregate credit exposure from energy related transactions totaled $11 million, based on settlement and mark-to-market exposures, net of collateral. The majority of the exposure is comprised of one counterparty, that is not rated by nationally recognized credit rating agencies.

Northern Natural Gas' primary customers include utilities in the upper Midwest. Kern River's primary customers are major oil and natural gas companies or affiliates of such companies, electric generating companies, energy marketing and trading companies, financial institutions and natural gas distribution utilities which provide services in Utah, Nevada and California. As a general policy, collateral is not required for receivables from creditworthy customers. Customers' financial condition and creditworthiness, as defined by the tariff, are regularly evaluated and historical losses have been minimal. In order to provide protection against credit risk, and as permitted by the separate terms of each of Northern Natural Gas' and Kern River's tariffs, the companies have required customers that lack creditworthiness to provide cash deposits, letters of credit or other security until they meet the creditworthiness requirements of the respective tariff.

Northern Powergrid

The Northern Powergrid Distribution Companies charge fees for the use of their distribution systems to supply companies. The supply companies, which purchase electricity from generators and traders and sell the electricity to end-use customers, use the Northern Powergrid Distribution Companies' distribution networks pursuant to the multilateral "Distribution Connection and Use of System Agreement." The Northern Powergrid Distribution Companies' customers are concentrated in a small number of electricity supply businesses with RWE Npower PLC accounting for approximately 24% of distribution revenue in 2015. The industry operates in accordance with a framework which sets credit limits for each supply business based on its credit rating or payment history and requires them to provide credit cover if their value at risk (measured as being equivalent to 45 days usage) exceeds the credit limit. Acceptable credit typically is provided in the form of a parent company guarantee, letter of credit or an escrow account. Ofgem has indicated that, provided the Northern Powergrid Distribution Companies have implemented credit control, billing and collection in line with best practice guidelines and can demonstrate compliance with the guidelines or are able to satisfactorily explain departure from the guidelines, any bad debt losses arising from supplier default will be recovered through an increase in future allowed income. Losses incurred to date have not been material.

AltaLink

AltaLink's primary source of operating revenue is the AESO, an entity rated AA- by Standard and Poor's. Because of the dependence on a single customer, any material failure of the customer to fulfill its obligations would significantly impair AltaLink's ability to meet its existing and future obligations. Total operating revenue for AltaLink was $592 million for the year ended December 31, 2015.

BHE Renewables

BHE Renewables owns independent power projects in the United States and the Philippines that generally have separate project financing agreements. These projects source of operating revenue is derived primarily from long-term power purchase agreements with single customers, primarily utilities, which expire between 2016 and 2040. Because of the dependence generally from a single customer at each project, any material failure of the customer to fulfill its obligations would significantly impair that project's ability to meet its existing and future obligations. Total operating revenue for BHE Renewables was $728 million for the year ended December 31, 2015.

Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Berkshire Hathaway Energy Company
Des Moines, Iowa

We have audited the accompanying consolidated balance sheets of Berkshire Hathaway Energy Company and subsidiaries (the "Company") as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2015. Our audits also included the financial statement schedules listed in the Index at Item 15(a)(ii). These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedules 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 Berkshire Hathaway Energy Company and subsidiaries as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly in all material respects the information set forth therein.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 26, 2016

BERKSHIRE HATHAWAY ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2015	**2014**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,108	$ 617
Trade receivables, net	1,785	1,837
Income taxes receivable	319	1,156
Inventories	882	826
Mortgage loans held for sale	335	286
Other current assets	814	930
Total current assets	5,243	5,652
Property, plant and equipment, net	60,769	59,248
Goodwill	9,076	9,343
Regulatory assets	4,155	4,000
Investments and restricted cash and investments	3,367	2,803
Other assets	1,008	770
Total assets	$ 83,618	$ 81,816

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

BERKSHIRE HATHAWAY ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (continued)
(Amounts in millions)

	As of December 31,	
	2015	**2014**
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 1,564	$ 1,991
Accrued interest	469	454
Accrued property, income and other taxes	372	366
Accrued employee expenses	264	255
Regulatory liabilities	402	163
Short-term debt	974	1,445
Current portion of long-term debt	1,148	1,232
Other current liabilities	896	1,203
Total current liabilities	6,089	7,109
Regulatory liabilities	2,631	2,669
BHE senior debt	7,814	7,810
BHE junior subordinated debentures	2,944	3,794
Subsidiary debt	26,066	25,616
Deferred income taxes	12,685	11,514
Other long-term liabilities	2,854	2,731
Total liabilities	61,083	61,243
Commitments and contingencies (Note 16)		
Equity:		
BHE shareholders' equity:		
Common stock - 115 shares authorized, no par value, 77 shares issued and outstanding	—	—
Additional paid-in capital	6,403	6,423
Retained earnings	16,906	14,513
Accumulated other comprehensive loss, net	(908)	(494)
Total BHE shareholders' equity	22,401	20,442
Noncontrolling interests	134	131
Total equity	22,535	20,573
Total liabilities and equity	$ 83,618	$ 81,816

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

BERKSHIRE HATHAWAY ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2015	**2014**	**2013**
Operating revenue:			
Energy	$ 15,354	$ 15,182	$ 10,826
Real estate	2,526	2,144	1,809
Total operating revenue	17,880	17,326	12,635
Operating costs and expenses:			
Energy:			
Cost of sales	5,079	5,732	3,799
Operating expense	3,732	3,501	2,794
Depreciation and amortization	2,399	2,028	1,527
Real estate	2,342	2,019	1,680
Total operating costs and expenses	13,552	13,280	9,800
Operating income	4,328	4,046	2,835
Other income (expense):			
Interest expense	(1,904)	(1,711)	(1,222)
Capitalized interest	74	89	84
Allowance for equity funds	91	98	78
Interest and dividend income	107	38	15
Other, net	39	42	51
Total other income (expense)	(1,593)	(1,444)	(994)
Income before income tax expense and equity income (loss)	2,735	2,602	1,841
Income tax expense	450	589	130
Equity income (loss)	115	109	(35)
Net income	2,400	2,122	1,676
Net income attributable to noncontrolling interests	30	27	40
Net income attributable to BHE shareholders	$ 2,370	$ 2,095	$ 1,636

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

BERKSHIRE HATHAWAY ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Amounts in millions)

	Years Ended December 31,		
	2015	2014	2013
Net income	$ 2,400	$ 2,122	$ 1,676
Other comprehensive (loss) income, net of tax:			
Unrecognized amounts on retirement benefits, net of tax of $17, $19 and $7	52	69	16
Foreign currency translation adjustment	(680)	(314)	74
Unrealized gains (losses) on available-for-sale securities, net of tax of $129, $(84) and $178	225	(134)	263
Unrealized (losses) gains on cash flow hedges, net of tax of $(7), $(13) and $10	(11)	(18)	13
Total other comprehensive (loss) income, net of tax	(414)	(397)	366
Comprehensive income	1,986	1,725	2,042
Comprehensive income attributable to noncontrolling interests	30	27	40
Comprehensive income attributable to BHE shareholders	$ 1,956	$ 1,698	$ 2,002

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

BERKSHIRE HATHAWAY ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(Amounts in millions)

	BHE Shareholders' Equity						
	Common		Additional Paid-in	Retained	Accumulated Other Comprehensive	Noncontrolling	Total
	Shares	Stock	Capital	Earnings	Loss, Net	Interests	Equity
Balance, December 31, 2012	75	$ —	$ 5,423	$ 10,782	$ (463)	$ 168	$ 15,910
Net income	—	—	—	1,636	—	24	1,660
Other comprehensive income	—	—	—	—	366	—	366
Distributions	—	—	—	—	—	(22)	(22)
Redemption of preferred securities of subsidiaries	—	—	—	—	—	(68)	(68)
Common stock issuances	2	—	1,000	—	—	—	1,000
Other equity transactions	—	—	(33)	—	—	3	(30)
Balance, December 31, 2013	77	—	6,390	12,418	(97)	105	18,816
Net income	—	—	—	2,095	—	17	2,112
Other comprehensive loss	—	—	—	—	(397)	—	(397)
Distributions	—	—	—	—	—	(22)	(22)
Other equity transactions	—	—	33	—	—	31	64
Balance, December 31, 2014	77	—	6,423	14,513	(494)	131	20,573
Adoption of ASC 853	—	—	—	56	—	11	67
Net income	—	—	—	2,370	—	18	2,388
Other comprehensive loss	—	—	—	—	(414)	—	(414)
Distributions	—	—	—	—	—	(21)	(21)
Common stock purchases	—	—	(3)	(33)	—	—	(36)
Other equity transactions	—	—	(17)	—	—	(5)	(22)
Balance, December 31, 2015	77	$ —	$ 6,403	$ 16,906	$ (908)	$ 134	$ 22,535

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

BERKSHIRE HATHAWAY ENERGY COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31,		
	2015	**2014**	**2013**
Cash flows from operating activities:			
Net income	$ 2,400	$ 2,122	$ 1,676
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	2,428	2,057	1,560
Allowance for equity funds	(91)	(98)	(78)
Equity (income) loss, net of distributions	(38)	(79)	52
Changes in regulatory assets and liabilities	356	(168)	(6)
Deferred income taxes and amortization of investment tax credits	1,265	2,335	996
Other, net	11	147	20
Changes in other operating assets and liabilities, net of effects from acquisitions:			
Trade receivables and other assets	(9)	(44)	75
Derivative collateral, net	(14)	(70)	48
Pension and other postretirement benefit plans	(11)	86	(42)
Accrued property, income and other taxes	877	(1,117)	189
Accounts payable and other liabilities	(194)	(25)	179
Net cash flows from operating activities	6,980	5,146	4,669
Cash flows from investing activities:			
Capital expenditures	(5,875)	(6,555)	(4,307)
Acquisitions, net of cash acquired	(164)	(2,956)	(5,536)
(Increase) decrease in restricted cash and investments	(28)	173	(234)
Purchases of available-for-sale securities	(144)	(150)	(228)
Proceeds from sales of available-for-sale securities	142	118	191
Equity method investments	(202)	(37)	(93)
Other, net	41	(11)	13
Net cash flows from investing activities	(6,230)	(9,418)	(10,194)
Cash flows from financing activities:			
Proceeds from BHE senior debt	—	1,478	1,981
Proceeds from BHE junior subordinated debentures	—	1,500	2,594
Proceeds from issuance of BHE common stock	—	—	1,000
Repayments of BHE senior debt and junior subordinated debentures	(850)	(550)	—
Common stock purchases	(36)	—	—
Proceeds from subsidiary debt	2,479	1,257	2,460
Repayments of subsidiary debt	(1,354)	(971)	(1,156)
Net (repayments of) proceeds from short-term debt	(421)	1,055	(849)
Other, net	(73)	(44)	(104)
Net cash flows from financing activities	(255)	3,725	5,926
Effect of exchange rate changes	(4)	(11)	(2)
Net change in cash and cash equivalents	491	(558)	399
Cash and cash equivalents at beginning of period	617	1,175	776
Cash and cash equivalents at end of period	$ 1,108	$ 617	$ 1,175

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

(1) Organization and Operations

Berkshire Hathaway Energy Company ("BHE") is a holding company that owns subsidiaries principally engaged in energy businesses (collectively with its subsidiaries, the "Company"). BHE is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

The Company's operations are organized and managed as eight business segments: PacifiCorp, MidAmerican Funding, LLC ("MidAmerican Funding") (which primarily consists of MidAmerican Energy Company ("MidAmerican Energy")), NV Energy, Inc. ("NV Energy") (which primarily consists of Nevada Power Company ("Nevada Power") and Sierra Pacific Power Company ("Sierra Pacific")), Northern Powergrid Holdings Company ("Northern Powergrid") (which primarily consists of Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc), BHE Pipeline Group (which consists of Northern Natural Gas Company ("Northern Natural Gas") and Kern River Gas Transmission Company ("Kern River")), BHE Transmission (which consists of BHE Canada Holdings Corporation ("AltaLink") (which primarily consists of AltaLink, L.P. ("ALP")) and BHE U.S. Transmission, LLC), BHE Renewables and HomeServices of America, Inc. (collectively with its subsidiaries, "HomeServices"). The Company, through these businesses, owns four utility companies in the United States serving customers in 11 states, two electricity distribution companies in Great Britain, two interstate natural gas pipeline companies in the United States, an electric transmission business in Canada, interests in electric transmission businesses in the United States, a renewable energy business primarily selling power generated from solar, wind, geothermal and hydro sources under long-term contracts, the second largest residential real estate brokerage firm in the United States and one of the largest residential real estate brokerage franchise networks in the United States.

(2) Summary of Significant Accounting Policies

Basis of Consolidation and Presentation

The Consolidated Financial Statements include the accounts of BHE and its subsidiaries in which it holds a controlling financial interest as of the financial statement date. The Consolidated Statements of Operations include the revenue and expenses of any acquired entities from the date of acquisition. 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; impairment of goodwill; recovery of long-lived assets; certain assumptions made in accounting for pension and other postretirement benefits; asset retirement obligations ("AROs"); income taxes; unbilled revenue; fair value of assets acquired and liabilities assumed in business combinations; 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, MidAmerican Energy, Nevada Power, Sierra Pacific, Northern Natural Gas, Kern River and ALP (the "Regulated Businesses") prepare their financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, the Regulated Businesses defer the recognition of certain costs or income if it is probable that, through the ratemaking process, there will be a corresponding increase or decrease in future regulated 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 regulated rates occur.

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

Fair Value Measurements

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

Cash Equivalents and Restricted Cash and Investments

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

Investments

The Company's management determines the appropriate classification of investments in debt and equity securities at the acquisition date and reevaluates the classification at each balance sheet date. Investments and restricted cash and investments that management does not intend to use or is restricted from using in current operations are presented as noncurrent on the Consolidated Balance Sheets.

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. Realized and unrealized gains and losses on securities in a trust related to the decommissioning of nuclear generation assets are recorded as a net regulatory liability since the Company expects to recover costs for these activities through regulated rates. Trading securities are carried at fair value with realized and unrealized gains and losses recognized in earnings. Held-to-maturity securities are carried at amortized cost, reflecting the ability and intent to hold the securities to maturity.

The Company 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, the Company records the investment at cost and subsequently increases or decreases the carrying value of the investment by the Company's proportionate share of the net earnings or losses and other comprehensive income (loss) ("OCI") of the investee. The Company records dividends or other equity distributions as reductions in the carrying value of the investment. Certain equity investments are presented on the Consolidated Balance Sheets net of related investment tax credits.

Investments gains and losses arise when investments are sold (as determined on a specific identification basis) or are other-than-temporarily impaired. If a decline in value of an investment below cost is deemed other than temporary, the cost of the investment is written down to fair value, with a corresponding charge to earnings. Factors considered in judging whether an impairment is other than temporary include: the financial condition, business prospects and creditworthiness of the issuer; the relative amount of the decline; the Company's ability and intent to hold the investment until the fair value recovers; and the length of time that fair value has been less than cost. Impairment losses on equity securities are charged to earnings. With respect to an investment in a debt security, any resulting impairment loss is recognized in earnings if the Company intends to sell, or expects to be required to sell, the debt security before its amortized cost is recovered. If the Company does not expect to ultimately recover the amortized cost basis even if it does not intend to sell the security, the credit loss component is recognized in earnings and any difference between fair value and the amortized cost basis, net of the credit loss, is reflected in OCI. For regulated investments, any impairment charge is offset by the establishment of a regulatory asset to the extent recovery in regulated rates is probable.

Allowance for Doubtful Accounts

Trade receivables are stated at the outstanding principal amount, net of an estimated allowance for doubtful accounts. The allowance for doubtful accounts is based on the Company's assessment of the collectibility of amounts owed to the Company by its customers. This assessment requires judgment regarding the ability of customers to pay or the outcome of any pending disputes. As of December 31, 2015 and 2014, the allowance for doubtful accounts totaled $31 million and $37 million, respectively, and is included in trade receivables, net on the Consolidated Balance Sheets.

Derivatives

The Company employs a number of different derivative contracts, which may include forwards, futures, options, swaps and other agreements, to manage its commodity price, interest rate, and foreign currency exchange 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. Cash collateral received from or paid to counterparties to secure derivative contract assets or liabilities in excess of amounts offset is included in other current assets on the Consolidated Balance Sheets.

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 cost of sales on the Consolidated Statements of Operations.

For the Company's derivatives not designated as hedging contracts, the settled amount is generally included in regulated 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 regulated rates are recorded as regulatory assets and liabilities. For the Company's derivatives not designated as hedging contracts and for which changes in fair value are not recorded as regulatory assets and liabilities, unrealized gains and losses are recognized on the Consolidated Statements of Operations as operating revenue for sales contracts; cost of sales and operating expense for purchase contracts and electricity, natural gas and fuel swap contracts; and other, net for interest rate swap derivatives.

For the Company's derivatives designated as hedging contracts, the Company formally assesses, at inception and thereafter, whether the hedging contract is highly effective in offsetting changes in the hedged item. The Company formally documents hedging activity by transaction type and risk management strategy.

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

Inventories

Inventories consist mainly of fuel, which includes coal stocks, stored gas and fuel oil, totaling $353 million and $320 million as of December 31, 2015 and 2014, respectively, and materials and supplies totaling $529 million and $506 million as of December 31, 2015 and 2014, respectively. The cost of materials and supplies, coal stocks and fuel oil is determined primarily using the average cost method. The cost of stored gas is determined using either the last-in-first-out ("LIFO") method or the lower of average cost or market. With respect to inventories carried at LIFO cost, the replacement cost would be $8 million and $41 million higher as of December 31, 2015 and 2014, respectively.

Property, Plant and Equipment, Net

General

Additions to property, plant and equipment are recorded at cost. The Company capitalizes all construction-related material, direct labor and contract services, as well as indirect construction costs. Indirect construction costs include capitalized interest, including debt allowance for funds used during construction ("AFUDC"), and equity AFUDC, as applicable to the Regulated Businesses. 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. Additionally, MidAmerican Energy has regulatory arrangements in Iowa in which the carrying cost of certain utility plant has been reduced for amounts associated with electric returns on equity exceeding specified thresholds.

Depreciation and amortization are generally computed by applying the composite or straight-line method based on either estimated useful lives or mandated recovery periods as prescribed by the Company's various regulatory authorities. Depreciation studies are completed by the Regulated Businesses to determine the appropriate group lives, net salvage and group depreciation rates. These studies are reviewed and rates are ultimately approved by the applicable regulatory commission. 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 the Company 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 regulated facilities, is capitalized by the Regulated Businesses 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") and the Alberta Utilities Commission ("AUC"). After construction is completed, the Company 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

The Company recognizes AROs when it has a legal obligation to perform decommissioning, reclamation or removal activities upon retirement of an asset. The Company's AROs are primarily related to the decommissioning of nuclear generating facilities and obligations associated with its other generating facilities and offshore natural gas pipelines. 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. For the Regulated Businesses, 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.

Impairment

The Company evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. The impacts of regulation are considered when evaluating the carrying value of regulated assets.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of identifiable net assets acquired in business combinations. The Company evaluates goodwill for impairment at least annually and completed its annual review as of October 31. When evaluating goodwill for impairment, the Company estimates the fair value of the reporting unit. If the carrying amount of a reporting unit, including goodwill, exceeds the estimated fair value, then the identifiable assets, including identifiable intangible assets, and liabilities of the reporting unit are estimated at fair value as of the current testing date. The excess of the estimated fair value of the reporting unit over the current estimated fair value of net assets establishes the implied value of goodwill. The excess of the recorded goodwill over the implied goodwill value is charged to earnings as an impairment loss. Significant judgment is required in estimating the fair value of the reporting unit and performing goodwill impairment tests. The Company uses a variety of methods to estimate a reporting unit's fair value, principally discounted projected future net cash flows. Key assumptions used include, but are not limited to, the use of estimated future cash flows; multiples of earnings; and an appropriate discount rate. In estimating future cash flows, the Company incorporates current market information, as well as historical factors. As such, the determination of fair value incorporates significant unobservable inputs. During 2015 and 2014, the Company did not record any goodwill impairments. The Company recognized a goodwill impairment of $53 million during 2013.

The Company records goodwill adjustments for (a) the tax benefit associated with the excess of tax-deductible goodwill over the reported amount of goodwill and (b) changes to the purchase price allocation prior to the end of the measurement period, which is not to exceed one year from the acquisition date.

Revenue Recognition

Energy Businesses

Revenue from energy business customers is recognized as electricity or natural gas is delivered or services are provided. Revenue recognized includes billed and unbilled amounts. As of December 31, 2015 and 2014, unbilled revenue was $660 million and $666 million, respectively, and is included in trade receivables, net on the Consolidated Balance Sheets. Rates for energy businesses are established by regulators or contractual arrangements. When preliminary regulated rates are permitted to be billed prior to final approval by the applicable regulator, certain revenue collected may be subject to refund and a liability for estimated refunds is accrued. The Company 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.

Real Estate Commission Revenue, Mortgage Revenue and Franchise Royalty Fees

Commission revenue from real estate brokerage transactions and related amounts due to agents are recognized when a real estate transaction is closed. Title and escrow closing fee revenue from real estate transactions and related amounts due to the title insurer are recognized at closing. Mortgage fee revenue consists of amounts earned related to application and underwriting fees, and fees on canceled loans. Fees associated with the origination and acquisition of mortgage loans are recognized as earned. Franchise royalty fees are based on a percentage of commissions earned by franchisees on real estate sales and are recognized when the sale closes.

Unamortized Debt Premiums, Discounts and Debt Issuance Costs

Premiums, discounts and debt issuance costs incurred for the issuance of long-term debt are amortized over the term of the related financing using the effective interest method.

Foreign Currency

The accounts of foreign-based subsidiaries are measured in most instances using the local currency of the subsidiary as the functional currency. Revenue and expenses of these businesses are translated into United States dollars at the average exchange rate for the period. Assets and liabilities are translated at the exchange rate as of the end of the reporting period. Gains or losses from translating the financial statements of foreign-based operations are included in equity as a component of AOCI. Gains or losses arising from transactions denominated in a currency other than the functional currency of the entity that is party to the transaction are included in earnings.

Income Taxes

Berkshire Hathaway includes the Company in its United States federal income tax return. The Company'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, MidAmerican Energy, Nevada Power and Sierra Pacific (the "Utilities") are required to pass on to their customers in most state jurisdictions are charged or credited directly to a regulatory asset or liability. As of December 31, 2015 and 2014, these amounts were recognized as regulatory assets of $1.5 billion and $1.4 billion, respectively, and regulatory liabilities of $29 million and $24 million, respectively, and will be included in regulated 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.

The Company has not established deferred income taxes on the undistributed foreign earnings of Northern Powergrid or AltaLink or the related currency translation adjustment that have been determined by management to be reinvested indefinitely. The cumulative undistributed foreign earnings were approximately $3.0 billion as of December 31, 2015. The Company periodically evaluates its capital requirements. If circumstances change in the future and a portion of Northern Powergrid's or AltaLink's undistributed earnings were repatriated, the dividends would be subject to taxation in the United States. However, any United States income tax liability would be offset, in part, by available United States income tax credits with respect to corporate income taxes previously paid in the United Kingdom and Canada. Because of the availability of foreign income tax credits, it is not practicable to determine the United States income tax liability that would be recognized if such cumulative earnings were not reinvested indefinitely. The Company has established deferred income taxes on all other undistributed foreign earnings. If opportunities become available to repatriate any available cash without triggering incremental United States income tax expense, the Company may distribute certain foreign earnings of Northern Powergrid and AltaLink.

In determining the Company's income taxes, management is required to interpret complex income tax laws and regulations, which includes consideration of regulatory implications imposed by the Company's various regulatory jurisdictions. The Company's income tax returns are subject to continuous examinations by federal, state, local and foreign 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. The Company 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 the Company's federal, state, local and foreign income tax examinations is uncertain, the Company 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 the Company's consolidated financial results. The Company's unrecognized tax benefits are primarily included in accrued property, income and other taxes and other long-term liabilities on the Consolidated Balance Sheets. Estimated interest and penalties, if any, related to uncertain tax positions are included as a component of income tax expense on the Consolidated Statements of Operations.

New Accounting Pronouncements

In January 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2016-01, which amends FASB Accounting Standards Codification ("ASC") Subtopic 825-10, "Financial Instruments - Overall." The amendments in this guidance address certain aspects of recognition, measurement, presentation and disclosure of financial instruments including a requirement that all investments in equity securities that do not qualify for equity method accounting or result in consolidation of the investee be measured at fair value with changes in fair value recognized in net income. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption not permitted, and is required to be adopted prospectively by means of a cumulative-effect adjustment to the balance sheet as of the beginning of the fiscal year of adoption. The Company is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In November 2015, the FASB issued ASU No. 2015-17, which amends FASB ASC Topic 740, "Income Taxes." The amendments in this guidance require that deferred income tax liabilities and assets be classified as noncurrent in the balance sheet. This guidance is effective for interim and annual reporting periods beginning after December 15, 2016, with early adoption permitted, and may be adopted prospectively or retrospectively for each period presented to reflect the new guidance. The Company early adopted this guidance as of December 31, 2015 under a retrospective method, resulting in decreases in other current assets of $291 million, other current liabilities of $3 million and noncurrent deferred income tax liabilities of $288 million as of December 31, 2014.

In April 2015, the FASB issued ASU No. 2015-03, which amends FASB ASC Subtopic 835-30, "Interest - Imputation of Interest." The amendments in this guidance require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability instead of as an asset. This guidance is effective for interim and annual reporting periods beginning after December 15, 2015, with early adoption permitted. This guidance must be adopted retrospectively, wherein the balance sheet of each period presented should be adjusted to reflect the new guidance. The Company early adopted this guidance as of December 31, 2015 under a retrospective method, resulting in a decrease in other assets of $197 million, BHE senior debt of $50 million and subsidiary debt of $147 million as of December 31, 2014.

In May 2014, the FASB issued ASU No. 2014-09, which creates FASB 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. In August 2015, the FASB issued ASU No. 2015-14, which defers the effective date of ASU No. 2014-09 one year to interim and annual reporting periods beginning after December 15, 2017. This guidance may be adopted retrospectively or under a modified retrospective method where the cumulative effect is recognized at the date of initial application. The Company is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In January 2014, the FASB issued ASU No. 2014-05, which amends FASB ASC Topic 853, "Service Concession Arrangements" ("ASC 853"). The amendments in this guidance require an entity to not account for service concession arrangements as a lease and should also not recognize them as property, plant and equipment. This guidance is effective for interim and annual reporting periods beginning after December 15, 2014. The Company adopted this guidance effective January 1, 2015 under a modified retrospective method where the cumulative effect is recognized at the date of initial application. The adoption resulted in the establishment of a financial asset with a related recognition of interest income, the elimination of a portion of previously recognized property, plant and equipment, the elimination of recognizing guaranteed water and energy delivery fees in operating revenue and increases to retained earnings attributable to the Company of $56 million and noncontrolling interests of $11 million.

(3) Business Acquisitions

BHE owns a highly diversified portfolio of businesses comprised primarily of regulated utilities. Consistent with BHE's strategy to grow and further diversify through a disciplined acquisition approach, the Company closed on several acquisitions during 2015, 2014 and 2013.

AltaLink

Transaction Description

On December 1, 2014, BHE completed its acquisition of AltaLink and AltaLink became an indirect wholly owned subsidiary of BHE ("AltaLink Transaction"). Under the terms of the Share Purchase Agreement, dated May 1, 2014, among BHE and SNC-Lavalin Group Inc. ("SNC-Lavalin"), BHE paid C$3.1 billion (US$2.7 billion) in cash to SNC-Lavalin for 100% of the equity interests of AltaLink. BHE funded the total purchase price with $1.5 billion of junior subordinated debentures issued and sold to subsidiaries of Berkshire Hathaway, $1.0 billion borrowed under its commercial paper program and cash on hand.

ALP is a regulated electric transmission business, headquartered in Calgary, Alberta. ALP owns 8,100 miles of transmission lines and 300 substations in Alberta and operates under a cost-of-service regulatory model, including a forward test year, overseen by the Alberta Utilities Commission ("AUC").

The transaction was approved by both the SNC-Lavalin and BHE boards of directors in May 2014. In June 2014, an Advance Ruling Certificate was received from the Commissioner of Competition, providing clearance for the AltaLink acquisition. In July 2014, the Canadian Minister of Industry approved the transaction under the Investment Canada Act, determining that the AltaLink Transaction constitutes a net benefit to Canada. In November 2014, approval by the AUC was received. In connection with the approval of the transaction under the Investment Canada Act, various commitments were made to the Canadian Minister of Industry. The commitments included, among others:

- AltaLink will remain locally managed and incorporated under the laws of Canada, with its headquarters, senior management team and operations located in Alberta.
- AltaLink's independent board of directors will continue to be comprised of a majority of Canadians.
- There will be no reductions in employment levels at AltaLink as a result of the transaction.
- Reinvest 100% of AltaLink's earnings back into AltaLink, elsewhere in Alberta or other regions of Canada for five years. This commitment will support AltaLink's C$2.7 billion investment in Alberta's energy infrastructure planned over the next three years, subject to continued oversight by the AUC and the Alberta Electric System Operator.
- Spend at least C$27 million to pursue joint development opportunities with Canadian partners in Canada and the United States.
- Invest at least C$3 million of new funds to support Alberta-based academic programs focused on energy-related topics, cultural organizations and community-based programs.
- Maintain AltaLink's commitment to provide C$3 million over three years in community and charitable contributions across Alberta.
- Share best practices with AltaLink on safety, customer satisfaction, cybersecurity and supplier diversity at no cost.
- Provide opportunities for Albertan and other Canadian companies to supply products and services to other BHE businesses.

Included in BHE's Consolidated Statement of Operations within the BHE Transmission reportable segment for the year ended December 31, 2014 is $13 million of net income as a result of including AltaLink's revenue and expenses from December 1, 2014. Additionally, BHE incurred $3 million of direct transaction costs associated with the AltaLink Transaction that are included in operating expense on the Consolidated Statement of Operations for the year ended December 31, 2014.

Allocation of Purchase Price

The operations of ALP are subject to the rate-setting authority of the AUC and are accounted for pursuant to GAAP, including the authoritative guidance for regulated operations. The rate-setting and cost recovery provisions establish rates on a cost-of-service basis designed to allow ALP an opportunity to recover its costs of providing service and a return on its investment in rate base. Except for certain assets not currently in rates, the fair value of ALP's assets acquired and liabilities assumed subject to these rate-setting provisions are assumed to approximate their carrying values and, therefore, no fair value adjustments have been reflected related to these amounts.

The fair value of AltaLink's assets acquired and liabilities assumed not subject to the rate-setting provisions discussed above was determined using an income approach. This approach is based on significant estimates and assumptions, including Level 3 inputs, which are judgmental in nature. The estimates and assumptions include the projected timing and amount of future cash flows, discount rates reflecting the risk inherent in the future cash flows and future market prices.

AltaLink's non-regulated assets acquired and liabilities assumed consist principally of AltaLink Investments, L.P.'s and AltaLink Holdings, L.P.'s senior bonds and debentures. The fair value of these liabilities was determined based on quoted market prices.

The following table summarizes the fair values of the assets acquired and liabilities assumed as of the acquisition date (in millions):

	Fair Value
Current assets, including cash and cash equivalents of $15	$ 174
Property, plant and equipment	5,610
Goodwill	1,744
Other long-term assets	141
Total assets	7,669
Current liabilities, including current portion of long-term debt of $79	866
Subsidiary debt, less current portion	3,772
Deferred income taxes	85
Other long-term liabilities	218
Total liabilities	4,941
Net assets acquired	$ 2,728

During 2015, the Company made revisions to certain assets not currently in rates, the fair value of certain contracts and certain contingencies based upon the receipt of additional information about the facts and circumstances that existed as of the acquisition date. Provisional amounts were subject to further revision for up to 12 months following the acquisition date until the related valuations were completed.

Goodwill

The excess of the purchase price paid over the estimated fair values of the identifiable assets acquired and liabilities assumed totaled $1.7 billion and is reflected as goodwill in the BHE Transmission reportable segment. The goodwill reflects the value for the opportunities to invest in Alberta's electric transmission infrastructure and to develop solutions to meet the long-term energy needs of Alberta. Goodwill is not amortized, but rather is reviewed annually for impairment or more frequently if indicators of impairment exist. None of the goodwill recognized is deductible for income tax purposes, and no deferred income taxes have been recorded related to the goodwill.

Pro Forma Financial Information

The following unaudited pro forma financial information reflects the consolidated results of operations of BHE, non-recurring transaction costs incurred by both BHE and AltaLink during 2014 and the amortization of the purchase price adjustments each assuming the acquisition had taken place on January 1, 2013 (in millions):

	2014	2013
Operating revenue	$ 17,888	$ 13,130
Net income attributable to BHE shareholders	$ 2,155	$ 1,667

The unaudited pro forma financial information has been presented for illustrative purposes only and is not necessarily indicative of the consolidated results of operations that would have been achieved or the future consolidated results of operations of BHE.

NV Energy, Inc.

Transaction Description

On December 19, 2013, BHE completed the merger contemplated by the Agreement and Plan of Merger dated May 29, 2013, among BHE, Silver Merger Sub, Inc. ("Merger Sub"), BHE's wholly-owned subsidiary, and NV Energy, Inc. ("NV Energy"), whereby Merger Sub was merged into NV Energy and NV Energy became an indirect wholly-owned subsidiary of BHE ("NV Energy Transaction"). BHE funded the total purchase price of $5.6 billion, or $23.75 per share for 100% of NV Energy's outstanding common stock, by issuing $1.0 billion of common stock on December 19, 2013, issuing $2.6 billion of junior subordinated debentures to certain Berkshire Hathaway subsidiaries on December 19, 2013, and using $2.0 billion of cash, including certain proceeds from BHE's $2.0 billion senior debt issuance on November 8, 2013.

NV Energy owns two regulated public utilities, Nevada Power and Sierra Pacific (together, the "Nevada Utilities"), that provide electric service to 1.2 million regulated retail electric customers and 0.2 million regulated retail natural gas customers in Nevada.

Included in BHE's Consolidated Statement of Operations within the NV Energy reportable segment for the year ended December 31, 2013 are costs totaling $38 million, consisting of $22 million for amounts payable under NV Energy's change in control policy and $16 million for donations to NV Energy's charitable foundation, and a $20 million one-time bill credit to retail customers included as a reduction to operating revenue. Additionally, BHE incurred $5 million of direct transaction costs associated with the NV Energy Transaction that are included in operating expense on the Consolidated Statement of Operations for the year ended December 31, 2013.

Pro Forma Financial Information

The following unaudited pro forma financial information reflects the consolidated results of operations of BHE, non-recurring transaction, integration and other costs incurred by both BHE and NV Energy during 2013 totaling $74 million, after-tax, a one-time bill credit to retail customers of $13 million, after-tax, and the amortization of the purchase price adjustments each assuming the acquisition had taken place on January 1, 2012 (in millions):

	2013
Operating revenue	$ 15,561
Net income attributable to BHE shareholders	$ 1,867

The unaudited pro forma financial information has been presented for illustrative purposes only and is not necessarily indicative of the consolidated results of operations that would have been achieved or the future consolidated results of operations of BHE.

Other

In 2015, the Company completed various other acquisitions totaling $164 million. The purchase prices were allocated to the assets acquired and liabilities assumed in each acquisition. The assets acquired consisted of property, plant and equipment, development and construction costs for renewable projects, other working capital items, goodwill of $33 million and other identifiable intangible assets. The liabilities assumed totaled $84 million.

In 2014, the Company completed various other acquisitions totaling $243 million. The purchase price for each acquisition was allocated to the assets acquired and liabilities assumed, which related primarily to property, plant and equipment of $641 million, goodwill of $80 million, long-term debt of $231 million and noncurrent deferred income tax liabilities of $170 million for the remaining 50% interest in CE Generation, LLC ("CE Generation"), development and construction costs for the 300-megawatt ("MW") TX Jumbo Road Wind, LLC wind-powered generation project ("Jumbo Road Project") and real estate brokerage and mortgage businesses. There were no other material assets acquired or liabilities assumed.

In 2013, the Company completed various other acquisitions of residential real estate brokerage and mortgage businesses totaling $240 million. The purchase prices were allocated to the assets acquired and liabilities assumed in each acquisition. The assets acquired consisted of loans receivable and other working capital items, goodwill of $188 million and other identifiable intangible assets. The liabilities assumed totaled $271 million primarily related to mortgage lines of credit secured by the loans receivable acquired and other working capital items.

(4) Property, Plant and Equipment, Net

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

	Depreciable Life	2015	2014
Regulated assets:			
Utility generation, transmission and distribution systems	5-80 years	$ 69,248	$ 64,645
Interstate natural gas pipeline assets	3-80 years	6,755	6,660
		76,003	71,305
Accumulated depreciation and amortization		(22,682)	(21,447)
Regulated assets, net		53,321	49,858
Nonregulated assets:			
Independent power plants	5-30 years	4,751	4,362
Other assets	3-30 years	875	673
		5,626	5,035
Accumulated depreciation and amortization		(805)	(839)
Nonregulated assets, net		4,821	4,196
Net operating assets		58,142	54,054
Construction work-in-progress		2,627	5,194
Property, plant and equipment, net		$ 60,769	$ 59,248

Construction work-in-progress includes $2.3 billion and $4.3 billion as of December 31, 2015 and 2014, respectively, related to the construction of regulated assets.

PacifiCorp revised its depreciation rates effective January 1, 2014 based on results of a depreciation study approved by its state regulatory commissions. 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.

During the third quarter of 2013, MidAmerican Energy revised its depreciation rates for certain electric generating facilities based on the results of a new depreciation study. The new rates reflect longer estimated useful lives for wind-powered generating facilities placed in-service in 2011 and 2012 and a lower accrual rate for the cost of removal regulatory liability related to coal-fueled generating facilities. The effect of this change was to reduce depreciation and amortization expense by $20 million in 2013 and $49 million annually based on depreciable plant balances at the time of the change. Effective January 1, 2014, MidAmerican Energy revised depreciation rates for certain electric generating facilities based on the results of its 2013 Iowa electric retail rate case. The new depreciation rates reflect longer estimated useful lives for certain generating facilities. The effect of this change was to reduce depreciation and amortization expense by $50 million annually based on depreciable plant balances at the time of the change.

(5) Jointly Owned Utility Facilities

Under joint facility ownership agreements, the Domestic Regulated Businesses, as tenants in common, have undivided interests in jointly owned generation, transmission, distribution and pipeline common facilities. The Company 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 the Company's share of the expenses of these facilities.

The amounts shown in the table below represent the Company's share in each jointly owned facility as of December 31, 2015 (dollars in millions):

	Company Share	Facility In Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
PacifiCorp:				
Jim Bridger Nos. 1-4	67%	$ 1,289	$ 566	$ 83
Hunter No. 1	94	469	154	—
Hunter No. 2	60	293	94	—
Wyodak	80	457	198	3
Colstrip Nos. 3 and 4	10	239	128	2
Hermiston(1)	50	177	71	1
Craig Nos. 1 and 2	19	325	213	18
Hayden No. 1	25	76	30	—
Hayden No. 2	13	30	18	7
Foote Creek	79	39	24	—
Transmission and distribution facilities	Various	577	178	46
Total PacifiCorp		3,971	1,674	160
MidAmerican Energy:				
Louisa No. 1	88%	757	405	7
Quad Cities Nos. 1 and 2(2)	25	672	340	27
Walter Scott, Jr. No. 3	79	608	297	6
Walter Scott, Jr. No. 4(3)	60	448	91	—
George Neal No. 4	41	305	148	1
Ottumwa No. 1	52	554	184	3
George Neal No. 3	72	415	153	—
Transmission facilities	Various	245	83	2
Total MidAmerican Energy		4,004	1,701	46
NV Energy:				
Navajo	11%	203	141	1
Silverhawk	75	247	58	2
Valmy	50	382	209	2
Transmission facilities	Various	224	39	1
Total NV Energy		1,056	447	6
BHE Pipeline Group - common facilities	Various	285	158	1
Total		$ 9,316	$ 3,980	$ 213

(1) PacifiCorp has contracted to purchase the remaining 50% of the output of the Hermiston generating facility.

(2) Includes amounts related to nuclear fuel.

(3) Facility in-service and accumulated depreciation and amortization amounts are net of credits applied under Iowa revenue sharing arrangements totaling $319 million and $67 million, respectively.

(6) Regulatory Matters

Regulatory Assets

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

	Weighted Average Remaining Life	2015	2014
Deferred income taxes[1]	26 years	$ 1,577	$ 1,468
Employee benefit plans[2]	9 years	778	747
Asset disposition costs[3]	Various	307	329
Deferred net power costs	1 year	140	277
Asset retirement obligations	8 years	281	239
Unrealized loss on regulated derivative contracts	5 years	250	223
Abandoned projects	5 years	136	159
Unamortized contract values	8 years	110	123
Other	Various	706	688
Total regulatory assets		$ 4,285	$ 4,253
Reflected as:			
Current assets		$ 130	$ 253
Noncurrent assets		4,155	4,000
Total regulatory assets		$ 4,285	$ 4,253

(1) Amounts primarily represent income tax benefits related to state accelerated tax depreciation and certain property-related basis differences that were previously flowed through to customers and will be included in regulated rates when the temporary differences reverse.

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

(3) Includes amounts established as a result of the Utah mine disposition discussed below 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 Plan withdrawal and closure costs incurred to date considered probable of recovery.

The Company had regulatory assets not earning a return on investment of $2.3 billion and $2.6 billion as of December 31, 2015 and 2014, respectively.

Regulatory Liabilities

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

	Weighted Average Remaining Life	2015		2014	
Cost of removal[1]	28 years	$	2,167	$	2,215
Deferred net power costs	2 years		206		—
Asset retirement obligations	22 years		147		169
Levelized depreciation	26 years		199		169
Employee benefit plans[2]	12 years		13		20
Other	Various		301		259
Total regulatory liabilities		$	3,033	$	2,832
Reflected as:					
Current liabilities		$	402	$	163
Noncurrent liabilities			2,631		2,669
Total regulatory liabilities		$	3,033	$	2,832

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

(2) Represents amounts not yet recognized as a component of net periodic benefit cost that are to be returned to customers in future periods when recognized.

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 Plan and settle PacifiCorp's other postretirement benefit obligation for UMWA participants (collectively, the "Utah Mine Disposition").

In April 2015, PacifiCorp filed all-party settlement stipulations with the UPSC and the WPSC finding that the decision to enter into the Utah Mine Disposition transaction was prudent and in the public interest. The UPSC approved the stipulation in April 2015 and the WPSC approved the stipulation in May 2015. In May 2015, the OPUC issued its final order concluding that the Utah Mine Disposition transaction produces net benefits for customers and was in the public interest. The IPUC also issued an order in May 2015, approving the Utah Mine Disposition and ruling that the decision to enter into the transaction was prudent and in the public interest. Accordingly, in June 2015, PacifiCorp sold the specified Utah mining assets and the replacement and amended coal supply agreements became effective. Refer to Note 12 for discussion of the UMWA 1974 Pension Plan withdrawal and the settlement of the other postretirement benefit obligation for UMWA participants. The Deer Creek mine is currently idled and closure activities have begun.

In December 2014, PacifiCorp also filed an advice letter with the California Public Utilities Commission ("CPUC"). In July 2015, the CPUC Energy Division issued a letter requiring PacifiCorp to file a formal application for approval of the sale of certain Utah mining assets. Accordingly, in September 2015, PacifiCorp filed an application with the CPUC.

(7) Investments and Restricted Cash and Investments

Investments and restricted cash and investments consists of the following as of December 31 (in millions):

	2015	2014
Investments:		
BYD Company Limited common stock	$ 1,238	$ 881
Rabbi trusts	380	386
Other	130	126
Total investments	1,748	1,393
Equity method investments:		
Electric Transmission Texas, LLC	585	515
Bridger Coal Company	190	192
BHE Renewables tax equity investments	168	—
Other	160	161
Total equity method investments	1,103	868
Restricted cash and investments:		
Quad Cities Station nuclear decommissioning trust funds	429	424
Solar Star and Topaz Projects	95	66
Other	129	167
Total restricted cash and investments	653	657
Total investments and restricted cash and investments	$ 3,504	$ 2,918
Reflected as:		
Current assets	$ 137	$ 115
Noncurrent assets	3,367	2,803
Total investments and restricted cash and investments	$ 3,504	$ 2,918

Investments

BHE's investment in BYD Company Limited common stock is accounted for as an available-for-sale security with changes in fair value recognized in AOCI. The fair value of BHE's investment in BYD Company Limited common stock reflects a pre-tax unrealized gain of $1.0 billion and $649 million as of December 31, 2015 and 2014, respectively.

Rabbi trusts primarily hold corporate-owned life insurance on certain current and former key executives and directors. The Rabbi trusts were established to hold investments used to fund the obligations of various nonqualified executive and director compensation plans and to pay the costs of the trusts. The amount represents the cash surrender value of all of the policies included in the Rabbi trusts, net of amounts borrowed against the cash surrender value.

Equity Method Investments

BHE, through a subsidiary, owns 50% of Electric Transmission Texas, LLC, which owns and operates electric transmission assets in the Electric Reliability Council of Texas footprint. BHE, through a subsidiary, owns 66.67% of Bridger Coal Company ("Bridger Coal"), which is a coal mining joint venture that supplies coal to the Jim Bridger generating facility. Bridger Coal is being accounted for under the equity method of accounting as the power to direct the activities that most significantly impact Bridger Coal's economic performance are shared with the joint venture partner.

Restricted Cash and Investments

MidAmerican Energy has established a trust for the investment of funds for decommissioning the Quad Cities Nuclear Station Units 1 and 2 ("Quad Cities Station"). These investments in debt and equity securities are classified as available-for-sale and are reported at fair value. Funds are invested in the trust in accordance with applicable federal and state investment guidelines and are restricted for use as reimbursement for costs of decommissioning the Quad Cities Station, which are currently licensed for operation until December 2032.

(8) Short-Term Debt and Credit Facilities

The following table summarizes BHE's and its subsidiaries' availability under their credit facilities as of December 31, (in millions):

	BHE	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	AltaLink	Other	Total[1]
2015:								
Credit facilities	$ 2,000	$ 1,200	$ 609	$ 650	$ 221	$ 813	$ 928	$ 6,421
Less:								
Short-term debt	(253)	(20)	—	—	—	(401)	(300)	(974)
Tax-exempt bond support and letters of credit	(51)	(160)	(195)	—	—	(9)	—	(415)
Net credit facilities	$ 1,696	$ 1,020	$ 414	$ 650	$ 221	$ 403	$ 628	$ 5,032
2014:								
Credit facilities	$ 2,000	$ 1,200	$ 609	$ 650	$ 265	$ 1,119	$ 853	$ 6,696
Less:								
Short-term debt	(395)	(20)	(50)	—	(215)	(251)	(514)	(1,445)
Tax-exempt bond support and letters of credit	(28)	(398)	(195)	—	—	(4)	—	(625)
Net credit facilities	$ 1,577	$ 782	$ 364	$ 650	$ 50	$ 864	$ 339	$ 4,626

(1) The above table does not include unused credit facilities and letters of credit for investments that are accounted for under the equity method.

As of December 31, 2015, the Company was in compliance with the covenants of its credit facilities and letter of credit arrangements.

BHE

BHE has a $1.4 billion senior unsecured credit facility expiring in June 2017 and a $600 million senior unsecured credit facility expiring in June 2017. These credit facilities have a variable interest rate based on the London Interbank Offered Rate ("LIBOR") or a base rate, at BHE's option, plus a spread that varies based on BHE's credit ratings for its senior unsecured long-term debt securities. These credit facilities are for general corporate purposes and also support BHE's commercial paper program and provide for the issuance of letters of credit. As of December 31, 2015 and 2014, the weighted average interest rate on commercial paper borrowings outstanding was 0.66% and 0.49%, respectively. These credit facilities require that BHE's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.70 to 1.0 as of the last day of each quarter.

As of December 31, 2015 and 2014, BHE had $142 million and $125 million, respectively, of letters of credit outstanding, of which $51 million and $28 million as of December 31, 2015 and 2014 were issued under the credit facilities. These letters of credit primarily support power purchase agreements and debt service requirements at certain subsidiaries of BHE Renewables, LLC and expire through December 2016.

PacifiCorp

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 LIBOR 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, 2015 and 2014, the weighted average interest rate on commercial paper borrowings outstanding was 0.65% and 0.43%, respectively. 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, 2015 and 2014, PacifiCorp had $310 million and $451 million, respectively, of fully available letters of credit issued under committed arrangements, of which $10 million and $270 million as of December 31, 2015 and 2014 were issued under the credit facilities. These letters of credit support PacifiCorp's variable-rate tax-exempt bond obligations and expire through March 2017.

MidAmerican Funding

MidAmerican Energy has a $600 million unsecured credit facility expiring in March 2018. The credit facility, which supports MidAmerican Energy's commercial paper program and its variable-rate tax-exempt bond obligations and provides for the issuance of letters of credit, has a variable interest rate based on LIBOR or a base rate, at MidAmerican Energy's option, plus a spread that varies based on MidAmerican Energy's credit ratings for senior unsecured long-term debt securities. As of December 31, 2014, the weighted average interest rate on commercial paper borrowings outstanding was 0.35%. The credit facility requires that MidAmerican Energy'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.

NV Energy

Nevada Power has a $400 million secured credit facility expiring in March 2018 and Sierra Pacific has a $250 million secured credit facility expiring in March 2018. These credit facilities, which are for general corporate purposes and provide for the issuance of letters of credit, have a variable interest rate based on LIBOR or a base rate, at each of the Nevada Utilities' option, plus a spread that varies based on each of the Nevada Utilities' credit ratings for its senior secured long-term debt securities. Amounts due under each credit facility are collateralized by each of the Nevada Utilities' general and refunding mortgage bonds. The credit facilities require that each of the Nevada Utilities' ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.68 to 1.0 as of the last day of each quarter.

Northern Powergrid

Northern Powergrid has a £150 million unsecured credit facility expiring in April 2020. The credit facility has a variable interest rate based on sterling LIBOR plus a spread that varies based on its credit ratings. As of December 31,2014, $184 million was outstanding under the credit facility, with a weighted average interest rate of 1.75%. The credit facility requires that the ratio of consolidated senior total net debt, including current maturities, to regulated asset value not exceed 0.8 to 1.0 at Northern Powergrid and 0.65 to 1.0 at Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc as of June 30 and December 31. Northern Powergrid's interest coverage ratio shall not be less than 2.5 to 1.0. Additionally, as of December 31, 2014, Northern Powergrid had $31 million drawn on uncommitted bank facilities totaling £42 million, with a weighted average interest rate of 2.0%.

AltaLink

ALP has a C$750 million secured revolving credit facility expiring in December 2017, which provides support for borrowings under the unsecured commercial paper program and may also be used for general corporate purposes. The credit facility has a variable interest rate based on the Canadian bank prime lending rate or a spread above the Bankers' Acceptance rate, at ALP's option, based on ALP's credit ratings for its senior secured long-term debt securities. In addition, ALP has a C$75 million secured revolving credit facility expiring in December 2017, which may be used for general corporate purposes, capital expenditures and letters of credit. The credit facility has a variable interest rate based on the Canadian bank prime lending rate, United States base rate, United States LIBOR loan rate, or a spread above the Bankers' Acceptance rate, at ALP's option, based on ALP's credit ratings for its senior secured long-term debt securities. At the renewal date, ALP has the option to convert these facilities to one-year term facilities. The credit facilities require the consolidated indebtedness to total capitalization not exceed 0.75 to 1.0 measured as of the last day of each quarter. As of December 31, 2015 and 2014, ALP had $324 million and $104 million outstanding under these facilities at a weighted average interest rate of 0.85% and 1.26%, respectively.

AltaLink Investments, L.P. has a C$300 million unsecured revolving term credit facility expiring in December 2020, which may be used for operating expenses, capital expenditures, working capital needs and letters of credit to a maximum of C$10 million. The credit facility has a variable interest rate based on the Canadian bank prime lending rate, United States base rate, United States LIBOR loan rate, or a spread above the Bankers' Acceptance rate, at AltaLink Investments, L.P.'s option, based on AltaLink Investments, L.P.'s credit ratings for its senior unsecured long-term debt securities. The credit facility requires the consolidated total debt to capitalization to not exceed 0.8 to 1.0 and earnings before interest, taxes, depreciation and amortization to interest expense for the four fiscal quarters ended to not be less than 2.25 to 1.0 measured as of the last day of each quarter. As of December 31, 2015 and 2014, AltaLink Investments, L.P. had $77 million and $147 million outstanding under this facility at a weighted average interest rate of 0.89% and 1.30%, respectively.

HomeServices

HomeServices has a $350 million unsecured credit facility expiring in July 2018. The credit facility has a variable interest rate based on the prime lending rate or the LIBOR, at HomeServices' option, plus a spread that varies based on HomeServices' Total Leverage Ratio as defined in the agreement. As of December 31, 2014, HomeServices had $243 million outstanding under its credit facility with a weighted average interest rate of 1.41%.

Through its subsidiaries, HomeServices maintains mortgage lines of credit totaling $578 million and $503 million as of December 31, 2015 and 2014, respectively, used for mortgage banking activities that expire beginning in February 2016 through December 2016 or are due on demand. The mortgage lines of credit have variable rates based on LIBOR plus a spread. Collateral for these credit facilities is comprised of residential property being financed and is equal to the loans funded with the facilities. As of December 31, 2015 and 2014, HomeServices had $300 million and $271 million, respectively, outstanding under these mortgage lines of credit at a weighted average interest rate of 2.42% and 2.25%, respectively.

BHE Renewables Letters of Credit

In connection with their bond offerings, Topaz and Solar Star entered into separate letter of credit and reimbursement facilities totaling $646 million. Letters of credit issued under the letter of credit facilities will be used to (a) provide security under the power purchase agreement and large generator interconnection agreements, (b) fund the debt service reserve requirement and the operation and maintenance debt service reserve requirement, (c) provide security for remediation and mitigation liabilities, and (d) provide security in respect of conditional use permit sales tax obligations. As of December 31, 2015 and 2014, $600 million and $245 million, respectively, of letters of credit had been issued under these facilities.

As of December 31, 2015 and 2014, certain renewable projects collectively have letters of credit outstanding of $65 million and $63 million, respectively, primarily in support of the power purchase agreements associated with the projects.

(9) BHE Debt

Senior Debt

BHE senior debt represents unsecured senior obligations of BHE that are redeemable in whole or in part at any time generally with make-whole premiums. BHE senior debt consists of the following, including unamortized premiums, discounts and debt issuance costs, as of December 31 (in millions):

	Par Value	2015	2014
1.10% Senior Notes, due 2017	$ 400	$ 399	$ 399
5.75% Senior Notes, due 2018	650	648	648
2.00% Senior Notes, due 2018	350	348	348
2.40% Senior Notes, due 2020	350	348	348
3.75% Senior Notes, due 2023	500	497	497
3.50% Senior Notes, due 2025	400	397	397
8.48% Senior Notes, due 2028	475	477	477
6.125% Senior Bonds, due 2036	1,700	1,690	1,688
5.95% Senior Bonds, due 2037	550	547	547
6.50% Senior Bonds, due 2037	1,000	987	986
5.15% Senior Notes, due 2043	750	739	738
4.50% Senior Notes, due 2045	750	737	737
Total BHE Senior Debt	$ 7,875	$ 7,814	$ 7,810
Reflected as:			
Current liabilities		$ —	$ —
Noncurrent liabilities		7,814	7,810
Total BHE Senior Debt		$ 7,814	$ 7,810

Junior Subordinated Debentures

BHE junior subordinated debentures consists of the following as of December 31 (in millions):

	Par Value	2015	2014
Junior subordinated debentures, due 2043	$ 1,444	$ 1,444	$ 2,294
Junior subordinated debentures, due 2044	1,500	1,500	1,500
Total BHE junior subordinated debentures - noncurrent	$ 2,944	$ 2,944	$ 3,794

BHE issued junior subordinated debentures to certain subsidiaries of Berkshire Hathaway pursuant to an indenture, by and between BHE and The Bank of New York Mellon Trust Company, N.A., as trustee, dated as of December 19, 2013 and November 12, 2014. The junior subordinated debentures are unsecured and junior in right of payment to BHE's senior debt. The junior subordinated debentures (i) have a 30 year maturity; (ii) bear interest at a floating rate equal to (a) the greater of 1% and the LIBOR (the greater of such two rates, the "Base Rate") plus 200 basis points through the date prior to the third anniversary of the issuance date; (b) the Base Rate plus 300 basis points (or, if at least 50% of principal is repaid prior to the third anniversary of the issuance date, the Base Rate plus 200 basis points) from the third anniversary of the issuance date through the date prior to the seventh anniversary of the issuance date; and (c) the Base Rate plus 375 basis points from the seventh anniversary of the issuance date until the maturity of the junior subordinated debentures; and (iii) are redeemable at BHE's option from time to time at par plus accrued and unpaid interest. The holders are restricted from transferring the junior subordinated debentures except to Berkshire Hathaway and its subsidiaries. As of December 31, 2015 and 2014, the interest rate was 3.0%. Interest expense to Berkshire Hathaway for the years ended December 31, 2015, 2014 and 2013 was $104 million, $78 million and $3 million, respectively.

In February 2016, BHE provided notice of redemption for $500 million of the junior subordinated debentures due 2043 at par value to occur in March 2016.

(10) Subsidiary Debt

BHE's direct and indirect subsidiaries are organized as legal entities separate and apart from BHE and its other subsidiaries. Pursuant to separate financing agreements, substantially all of PacifiCorp's electric utility properties; the equity interest of MidAmerican Funding's subsidiary; MidAmerican Energy's electric utility properties in the state of Iowa; substantially all of Nevada Power's and Sierra Pacific's properties in the state of Nevada; the long-term customer contracts of Kern River; AltaLink's transmission properties; and substantially all of the assets of the subsidiaries of BHE Renewables are pledged or encumbered to support or otherwise provide the security for their related subsidiary debt. It should not be assumed that the assets of any subsidiary will be available to satisfy BHE's obligations or the obligations of its other subsidiaries. However, unrestricted cash or other assets which are available for distribution may, subject to applicable law, regulatory commitments and the terms of financing and ring-fencing arrangements for such parties, be advanced, loaned, paid as dividends or otherwise distributed or contributed to BHE or affiliates thereof. The long-term debt of subsidiaries may include provisions that allow BHE's subsidiaries to redeem it in whole or in part at any time. These provisions generally include make-whole premiums.

Distributions at these separate legal entities are limited by various covenants including, among others, leverage ratios, interest coverage ratios and debt service coverage ratios. As of December 31, 2015, all subsidiaries were in compliance with their long-term debt covenants.

Long-term debt of subsidiaries consists of the following, including fair value adjustments and unamortized premiums, discounts and debt issuance costs, as of December 31 (in millions):

	Par Value	2015	2014
PacifiCorp	$ 7,204	$ 7,159	$ 7,055
MidAmerican Funding	4,627	4,560	4,323
NV Energy	4,840	4,860	5,118
Northern Powergrid	2,735	2,772	2,317
BHE Pipeline Group	1,045	1,040	1,358
BHE Transmission	3,469	3,467	3,743
BHE Renewables	3,394	3,356	2,934
Total subsidiary debt	$ 27,314	$ 27,214	$ 26,848
Reflected as:			
Current liabilities		$ 1,148	$ 1,232
Noncurrent liabilities		26,066	25,616
Total subsidiary debt		$ 27,214	$ 26,848

PacifiCorp

PacifiCorp's long-term debt consists of the following, including unamortized premiums, discounts and debt issuance costs, as of December 31 (dollars in millions):

	Par Value	2015	2014
First mortgage bonds:			
5.50% to 8.635%, due through 2019	$ 855	$ 853	$ 859
2.95% to 8.53%, due 2021 to 2025	2,149	2,137	1,888
6.71% due 2026	100	100	100
5.25% to 7.70%, due 2031 to 2035	800	794	793
5.75% to 6.35%, due 2036 to 2039	2,500	2,480	2,479
4.10% due 2042	300	297	297
Variable-rate series, tax-exempt bond obligations (2015-0.01% to 0.22%; 2014-0.02% to 0.22%):			
Due 2018 to 2025(1)	107	107	223
Due 2016 to 2024(1)(2)	198	196	219
Due 2016 to 2025(2)	59	59	36
Due 2017 to 2018	91	91	91
Capital lease obligations - 8.75% to 15.678%, due through 2035	45	45	70
Total PacifiCorp	$ 7,204	$ 7,159	$ 7,055

(1) Supported by $310 million and $451 million of fully available letters of credit issued under committed bank arrangements as of December 31, 2015 and 2014, 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.

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, 2015.

MidAmerican Funding

MidAmerican Funding's long-term debt consists of the following, including fair value adjustments and unamortized premiums, discounts and debt issuance costs, as of December 31 (dollars in millions):

	Par Value	2015	2014
MidAmerican Funding:			
6.927% Senior Bonds, due 2029	$ 325	$ 289	$ 289
MidAmerican Energy:			
Tax-exempt bond obligations -			
Variable-rate series (2015-0.03%, 2014-0.07%), due 2016-2038	195	194	194
First Mortgage Bonds:			
2.40%, due 2019	500	499	498
3.70%, due 2023	250	248	248
3.50%, due 2024	500	502	296
4.80%, due 2043	350	345	345
4.40%, due 2044	400	394	394
4.25%, due 2046	450	444	—
Notes:			
5.95% Series, due 2017	250	250	250
5.3% Series, due 2018	350	349	349
6.75% Series, due 2031	400	395	395
5.75% Series, due 2035	300	298	298
5.8% Series, due 2036	350	347	347
Turbine purchase obligation, 1.43% due 2015(1)	—	—	420
Transmission upgrade obligation, 4.45% due through 2035	5	4	—
Capital lease obligations - 4.16%, due through 2020	2	2	—
Total MidAmerican Energy	4,302	4,271	4,034
Total MidAmerican Funding	$ 4,627	$ 4,560	$ 4,323

(1) In conjunction with the construction of wind-powered generating facilities in 2012, MidAmerican Energy accrued as property, plant and equipment amounts for turbine purchases it was not contractually obligated to pay until December 2015. The amount ultimately payable was discounted and recognized upon delivery of the equipment as long-term debt. The discount was amortized as interest expense over the period until payment was due using the effective interest method.

Pursuant to MidAmerican Energy's mortgage dated September 9, 2013, MidAmerican Energy's first mortgage bonds, currently and from time to time outstanding, are secured by a first mortgage lien on substantially all of its electric generating, transmission and distribution property within the state of Iowa, subject to certain exceptions and permitted encumbrances. As of December 31, 2015, MidAmerican Energy's eligible property subject to the lien of the mortgage totaled approximately $13 billion based on original cost. Additionally, MidAmerican Energy's senior notes outstanding are equally and ratably secured with the first mortgage bonds as required by the indentures under which the senior notes were issued.

NV Energy

NV Energy's long-term debt consists of the following, including fair value adjustments and unamortized premiums, discounts and debt issuance costs, as of December 31 (dollars in millions):

	Par Value	2015	2014
NV Energy -			
6.250% Senior Notes, due 2020	$ 315	$ 373	$ 384
Nevada Power:			
General and Refunding Mortgage Securities:			
5.875% Series L, due 2015	—	—	250
5.950% Series M, due 2016	210	210	209
6.500% Series O, due 2018	324	323	322
6.500% Series S, due 2018	499	498	497
7.125% Series V, due 2019	500	499	499
6.650% Series N, due 2036	367	356	356
6.750% Series R, due 2037	349	345	345
5.375% Series X, due 2040	250	247	247
5.450% Series Y, due 2041	250	235	234
Variable-rate series (2015-0.672% to 1.055%, 2014-0.455% to 0.464%):			
Pollution Control Revenue Bonds Series 2006A, due 2032	38	38	38
Pollution Control Revenue Bonds Series 2006, due 2036	38	37	37
Capital and financial lease obligations - 2.750% to 11.600%, due through 2054	497	497	510
Total Nevada Power	3,322	3,285	3,544
Sierra Pacific:			
General and Refunding Mortgage Securities:			
6.000% Series M, due 2016	450	450	451
3.375% Series T, due 2023	250	248	247
6.750% Series P, due 2037	252	255	255
Variable-rate series (2015-0.733% to 1.054%, 2014-0.464% to 0.466%):			
Pollution Control Revenue Bonds Series 2006A, due 2031	58	58	58
Pollution Control Revenue Bonds Series 2006B, due 2036	75	74	74
Pollution Control Revenue Bonds Series 2006C, due 2036	81	80	79
Capital and financial lease obligations - 2.700% to 8.548%, due through 2054	37	37	26
Total Sierra Pacific	1,203	1,202	1,190
Total NV Energy	$ 4,840	$ 4,860	$ 5,118

The issuance of General and Refunding Mortgage Securities by the Nevada Utilities is subject to PUCN approval and is limited by available property and other provisions of the mortgage indentures for each of Nevada Power and Sierra Pacific. As of December 31, 2015, approximately $8.7 billion of Nevada Power's and $3.7 billion of Sierra Pacific's (based on original cost) property was subject to the liens of the mortgages.

Northern Powergrid

Northern Powergrid and its subsidiaries' long-term debt consists of the following, including fair value adjustments and unamortized premiums, discounts and debt issuance costs, as of December 31 (dollars in millions):

	Par Value[1]	2015	2014
8.875% Bonds, due 2020	$ 147	$ 162	$ 172
9.25% Bonds, due 2020	295	315	338
3.901% to 4.586% European Investment Bank loans, due 2018 to 2022	398	398	420
7.25% Bonds, due 2022	295	306	324
2.50% Bonds due 2025	221	217	—
2.564% European Investment Bank loans, due 2027	369	368	—
7.25% Bonds, due 2028	273	280	297
4.375% Bonds, due 2032	221	217	229
5.125% Bonds, due 2035	295	291	307
5.125% Bonds, due 2035	221	218	230
Total Northern Powergrid	$ 2,735	$ 2,772	$ 2,317

(1) The par values for these debt instruments are denominated in sterling.

BHE Pipeline Group

BHE Pipeline Group' long-term debt consists of the following, including unamortized premiums, discounts and debt issuance costs, as of December 31 (dollars in millions):

	Par Value	2015	2014
Northern Natural Gas:			
5.125% Senior Notes, due 2015	$ —	$ —	$ 100
5.75% Senior Notes, due 2018	200	199	199
4.25% Senior Notes, due 2021	200	199	199
5.8% Senior Bonds, due 2037	150	149	149
4.1% Senior Bonds, due 2042	250	248	247
Total Northern Natural Gas	800	795	894
Kern River:			
6.676% Senior Notes, due 2016	—	—	165
4.893% Senior Notes, due 2018	245	245	299
Total Kern River	245	245	464
Total BHE Pipeline Group	$ 1,045	$ 1,040	$ 1,358

Kern River's long-term debt amortizes monthly. Kern River redeemed the remaining amount of its 6.676% Senior Notes due 2016 at a redemption price determined in accordance with the terms of the indenture. Kern River provides a debt service reserve letter of credit to cover the next six months of principal and interest payments due on the loans, which were equal to $33 million and $55 million as of December 31, 2015 and 2014, respectively.

BHE Transmission

BHE Transmission's long-term debt consists of the following, including fair value adjustments and unamortized premiums, discounts and debt issuance costs, as of December 31, (dollars in millions):

	Par Value[1]	2015	2014
AltaLink Investments, L.P.:			
Series 09-1 Senior Bonds, 5.207%, due 2016	$ 108	$ 112	$ 136
Series 12-1 Senior Bonds, 3.674%, due 2019	145	151	180
Series 13-1 Senior Bonds, 3.265%, due 2020	145	149	176
Series 15-1 Senior Bonds, 2.244%, due 2022	145	144	—
Total AltaLink Investments, L.P.	543	556	492
AltaLink Holdings, L.P. Senior debentures, 10.5%, due 2015	—	—	78
ALP:			
Series 2008-1 Notes, 5.243%, due 2018	145	145	171
Series 2013-2 Notes, 3.621%, due 2020	90	90	108
Series 2012-2 Notes, 2.978%, due 2022	199	198	236
Series 2013-4 Notes, 3.668%, due 2023	361	360	429
Series 2014-1 Notes, 3.399%, due 2024	253	252	300
Series 2006-1 Notes, 5.249%, due 2036	108	108	128
Series 2010-1 Notes, 5.381%, due 2040	90	90	108
Series 2010-2 Notes, 4.872%, due 2040	108	108	128
Series 2011-1 Notes, 4.462%, due 2041	199	198	236
Series 2012-1 Notes, 3.99%, due 2042	379	374	451
Series 2013-3 Notes, 4.922%, due 2043	253	252	300
Series 2014-3 Notes, 4.054%, due 2044	213	212	253
Series 2015-1 Notes, 4.090%, due 2045	253	251	—
Series 2013-1 Notes, 4.446%, due 2053	181	180	214
Series 2014-2 Notes, 4.274%, due 2064	94	93	111
Total AltaLink, L.P.	2,926	2,911	3,173
Total BHE Transmission	$ 3,469	$ 3,467	$ 3,743

(1) The par values for these debt instruments are denominated in Canadian dollars.

BHE Renewables

BHE Renewables' long-term debt consists of the following, including fair value adjustments and unamortized debt issuance costs, as of December 31 (dollars in millions):

	Par Value	2015	2014
Fixed-rate[1]:			
CE Generation Bonds, 7.416%, due 2018	$ 96	$ 97	$ 125
Salton Sea Funding Corporation Bonds, 7.475%, due 2018	50	51	71
Cordova Funding Corporation Bonds, 8.48% to 9.07%, due 2019	112	113	125
Bishop Hill Holdings Senior Notes, 5.125%, due 2032	104	102	107
Solar Star Funding Senior Notes, 3.950%, due 2035	325	321	—
Solar Star Funding Senior Notes, 5.375%, due 2035	1,000	988	987
Topaz Solar Farms Senior Notes, 5.750%, due 2039	826	815	838
Topaz Solar Farms Senior Notes, 4.875%, due 2039	242	239	247
Other	25	25	27
Variable-rate[1]:			
Pinyon Pines I and II Term Loans, due 2019[2]	380	378	398
Wailuku Special Purpose Revenue Bonds, 0.12%, due 2021	8	8	9
TX Jumbo Road Term Loan, 3.626%, due 2025	226	219	—
Total BHE Renewables	$ 3,394	$ 3,356	$ 2,934

(1) Amortizes quarterly or semiannually.

(2) The term loans have variable interest rates based on LIBOR plus a spread that varies during the term of the agreement. The weighted average variable interest rate as of December 31, 2015 and 2014 was 2.23% and 1.88%, respectively. The Company has entered into interest rate swaps that fix the interest rate on 75% of the outstanding debt. The weighted average fixed interest rate for the 75% portion is fixed at 3.55% as of December 31, 2015 and 2014.

Annual Repayments of Long-Term Debt

The annual repayments of BHE and subsidiary debt for the years beginning January 1, 2016 and thereafter, excluding fair value adjustments and unamortized premiums, discounts and debt issuance costs, are as follows (in millions):

	2016	2017	2018	2019	2020	2021 and Thereafter	Total
BHE senior notes	$ —	$ 400	$ 1,000	$ —	$ 350	$ 6,125	$ 7,875
BHE junior subordinated debentures	—	—	—	—	—	2,944	2,944
PacifiCorp	81	57	589	353	41	6,083	7,204
MidAmerican Funding	34	254	350	500	1	3,488	4,627
NV Energy	676	16	840	519	336	2,453	4,840
Northern Powergrid	—	—	59	59	500	2,117	2,735
BHE Pipeline Group	54	62	329	—	—	600	1,045
BHE Transmission	110	—	145	145	235	2,834	3,469
BHE Renewables	193	196	208	494	126	2,177	3,394
Totals	$ 1,148	$ 985	$ 3,520	$ 2,070	$ 1,589	$ 28,821	$ 38,133

(11) Income Taxes

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

	2015	2014	2013
Current:			
Federal	$ (929)	$ (1,872)	$ (985)
State	29	(3)	(2)
Foreign	84	129	121
	(816)	(1,746)	(866)
Deferred:			
Federal	1,310	2,296	1,306
State	(53)	37	(247)
Foreign	17	11	(59)
	1,274	2,344	1,000
Investment tax credits	(8)	(9)	(4)
Total	$ 450	$ 589	$ 130

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:

	2015	2014	2013
Federal statutory income tax rate	35%	35%	35%
Income tax credits	(11)	(10)	(14)
State income tax, net of federal income tax benefit	(1)	1	(9)
Income tax effect of foreign income	(7)	(3)	(6)
Equity income (loss)	2	2	(1)
Other, net	(2)	(2)	2
Effective income tax rate	16%	23%	7%

Income tax credits relate primarily to production tax credits from wind-powered generating facilities owned by MidAmerican Energy, PacifiCorp and BHE Renewables. Federal renewable electricity production tax credits are earned as energy from qualifying wind-powered generating facilities is produced and sold and are based on a per-kilowatt hour rate pursuant to the applicable federal income tax law. Wind-powered generating facilities are eligible for the credits for 10 years from the date the qualifying generating facilities are placed in-service.

State income tax benefits decreased for 2014 compared to 2013 primarily due to one-time deferred income tax benefits recognized from a reduction in the apportioned state tax rate of $161 million, in part, as a result of BHE's acquisition of NV Energy.

Income tax effect of foreign income includes, among other items, deferred income tax benefits of $39 million in 2015 and $54 million in 2013 related to the enactment of reductions in the United Kingdom corporate income tax rate. In November 2015 the corporate tax rate was reduced from 20% to 19% effective April 1, 2017, with a further reduction to 18% effective April 1, 2020. In July 2013 the corporate income tax rate was reduced from 23% to 21% effective April 1, 2014, with a further reduction to 20% effective April 1, 2015.

Berkshire Hathaway includes the Company in its United States federal income tax return. As of December 31, 2015 and 2014, the Company had current income taxes receivable from Berkshire Hathaway of $286 million and $1.1 billion, respectively.

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

	2015	2014
Deferred income tax assets:		
Federal, state and foreign carryforwards	$ 865	$ 781
Regulatory liabilities	834	812
AROs	317	249
Employee benefits	190	187
Derivative contracts	83	62
Other	815	781
Total deferred income tax assets	3,104	2,872
Valuation allowances	(35)	(23)
Total deferred income tax assets, net	3,069	2,849
Deferred income tax liabilities:		
Property-related items	(13,157)	(11,989)
Regulatory assets	(1,446)	(1,374)
Investments	(852)	(699)
Other	(299)	(301)
Total deferred income tax liabilities	(15,754)	(14,363)
Net deferred income tax liability	$ (12,685)	$ (11,514)

The following table provides the Company's net operating loss and tax credit carryforwards and expiration dates as of December 31, 2015 (in millions):

	Federal	State
Net operating loss carryforwards[(1)]	$ 185	$ 10,084
Deferred income taxes on net operating loss carryforwards	$ 69	$ 589
Expiration dates	2023-2026	2016-2035
Foreign and other tax credits[(2)]	$ 176	$ 31
Expiration dates	2023- indefinite	2016- indefinite

(1) The federal net operating loss carry forwards relate principally to net operating loss carry forwards of subsidiaries that are tax residents in both the United States and the United Kingdom. The net operating loss carry forwards were generated prior to Berkshire Hathaway Inc.'s ownership and will begin to expire in 2022.

(2) Includes $102 million of deferred foreign tax credits associated with the federal income tax on unremitted tax earnings and profit pools that will begin to be creditable and expire 10 years after the date the foreign earnings are repatriated through actual or deemed dividends. As of December 31, 2015 the statute of limitation had not begun on the foreign tax credit carryforwards.

The United States Internal Revenue Service has closed its examination of the Company's income tax returns through December 31, 2009. Most state tax agencies have closed their examinations of the Company's income tax returns through February 9, 2006, except for (i) Iowa, which is closed through December 31, 2012, (ii) Illinois, which is closed through December 31, 2008, and (iii) examinations of PacifiCorp's state returns, which have been closed through March 31, 2006 (except for the December 1995 and 1997 tax years in Utah). Examinations have been closed in the United Kingdom through at least 2010, in Canada through at least 2008 and in the Philippines through at least 2011.

A reconciliation of the beginning and ending balances of the Company's net unrecognized tax benefits is as follows for the years ended December 31 (in millions):

	2015	2014
Beginning balance	$ 220	$ 211
Additions based on tax positions related to the current year	3	11
Additions for tax positions of prior years	46	48
Reductions for tax positions of prior years	(58)	(50)
Statute of limitations	(6)	(1)
Settlements	(6)	—
Interest and penalties	(1)	1
Ending balance	$ 198	$ 220

As of December 31, 2015 and 2014, the Company had unrecognized tax benefits totaling $163 million and $188 million, respectively, that if recognized, would have an impact on the effective tax rate. The remaining unrecognized tax benefits relate 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 the Company's effective income tax rate.

(12) Employee Benefit Plans

Defined Benefit Plans

Domestic Operations

The Utilities sponsor defined benefit pension plans that cover a majority of all employees of BHE and its domestic energy subsidiaries. These pension plans include noncontributory defined benefit pension plans, supplemental executive retirement plans ("SERP") and a restoration plan for certain executives of NV Energy. The Utilities also provide certain postretirement healthcare and life insurance benefits through various plans to eligible retirees.

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		
	2015	2014	2013	2015	2014	2013
Service cost	$ 33	$ 36	$ 24	$ 11	$ 14	$ 14
Interest cost	121	131	87	31	46	33
Expected return on plan assets	(169)	(164)	(119)	(45)	(53)	(44)
Net amortization	53	44	58	(11)	(3)	6
Net periodic benefit cost (credit)	$ 38	$ 47	$ 50	$ (14)	$ 4	$ 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	
	2015	2014	2015	2014
Plan assets at fair value, beginning of year	$ 2,718	$ 2,711	$ 858	$ 852
Employer contributions	13	37	2	2
Participant contributions	—	—	9	11
Actual return on plan assets	(17)	188	—	54
Settlement	(23)	—	(150)	—
Benefits paid	(202)	(218)	(57)	(61)
Plan assets at fair value, end of year	$ 2,489	$ 2,718	$ 662	$ 858

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

	Pension		Other Postretirement	
	2015	2014	2015	2014
Benefit obligation, beginning of year	$ 3,119	$ 2,821	$ 936	$ 987
Service cost	33	36	11	14
Interest cost	121	131	31	46
Participant contributions	—	—	9	11
Actuarial loss (gain)	(110)	349	(43)	(61)
Amendment	(4)	—	3	—
Settlement	(23)	—	(150)	—
Benefits paid	(202)	(218)	(57)	(61)
Benefit obligation, end of year	$ 2,934	$ 3,119	$ 740	$ 936
Accumulated benefit obligation, end of year	$ 2,906	$ 3,086		

In conjunction with the Utah Mine Disposition described in Note 6, in December 2014, PacifiCorp's subsidiary, 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 a fund managed by the UMWA. Transfer of the assets and settlement of this obligation occurred in May 2015 and resulted in a remeasurement of the other postretirement plan assets and benefit obligation. As a result of the remeasurement, PacifiCorp recognized a $9 million settlement loss, with the portion that is probable of recovery deferred as a regulatory asset. No curtailment accounting was triggered as a result of the settlement due to an insignificant impact to the average remaining service lives in the plan. 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 associated with the UMWA plan participants to $150 million.

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	
	2015	2014	2015	2014
Plan assets at fair value, end of year	$ 2,489	$ 2,718	$ 662	$ 858
Benefit obligation, end of year	2,934	3,119	740	936
Funded status	$ (445)	$ (401)	$ (78)	$ (78)
Amounts recognized on the Consolidated Balance Sheets:				
Other assets	$ 7	$ 12	$ 15	$ 10
Other current liabilities	(15)	(14)	—	—
Other long-term liabilities	(437)	(399)	(93)	(88)
Amounts recognized	$ (445)	$ (401)	$ (78)	$ (78)

The SERPs and restoration plan have no plan assets; however, the Company has Rabbi trusts that hold corporate-owned life insurance and other investments to provide funding for the future cash requirements of the SERPs and restoration plan. The cash surrender value of all of the policies included in the Rabbi trusts, net of amounts borrowed against the cash surrender value, plus the fair market value of other Rabbi trust investments, was $228 million and $247 million as of December 31, 2015 and 2014, respectively. These assets are not included in the plan assets in the above table, but are reflected in noncurrent investments and restricted cash and investments on the Consolidated Balance Sheets.

The fair value of plan assets, projected benefit obligation and accumulated benefit obligation for (1) pension and other postretirement benefit plans with a projected benefit obligation in excess of the fair value of plan assets and (2) pension plans with an accumulated benefit obligation in excess of the fair value of plan assets as of December 31 are as follows (in millions):

	Pension		Other Postretirement	
	2015	2014	2015	2014
Fair value of plan assets	$ 1,811	$ 1,987	$ 413	$ 598
Projected benefit obligation	$ 2,263	$ 2,401	$ 505	$ 686
Accumulated benefit obligation	$ 2,244	$ 2,380		

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	
	2015	2014	2015	2014
Net loss	$ 768	$ 757	$ 97	$ 108
Prior service credit	(25)	(31)	(68)	(87)
Regulatory deferrals	(2)	(3)	8	2
Total	$ 741	$ 723	$ 37	$ 23

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2015 and 2014 is as follows (in millions):

	Regulatory Asset	Regulatory Liability	Accumulated Other Comprehensive Loss	Total
Pension				
Balance, December 31, 2013	$ 490	$ (58)	$ 9	$ 441
Net loss arising during the year	258	52	16	326
Net amortization	(38)	—	(6)	(44)
Total	220	52	10	282
Balance, December 31, 2014	710	(6)	19	723
Net loss (gain) arising during the year	76	5	(6)	75
Net prior service credit arising during the year	(4)	—	—	(4)
Net amortization	(53)	—	—	(53)
Total	19	5	(6)	18
Balance, December 31, 2015	$ 729	$ (1)	$ 13	$ 741

	Regulatory Asset	Regulatory Liability	Total
Other Postretirement			
Balance, December 31, 2013	$ 99	$ (16)	$ 83
Net (gain) loss arising during the year	(64)	1	(63)
Net amortization	2	1	3
Total	(62)	2	(60)
Balance, December 31, 2014	37	(14)	23
Net (gain) loss arising during the year	(1)	1	—
Net prior service cost arising during the year	3	—	3
Net amortization	10	1	11
Total	12	2	14
Balance, December 31, 2015	$ 49	$ (12)	$ 37

The net loss, prior service credit and regulatory deferrals that will be amortized in 2016 into net periodic benefit cost are estimated to be as follows (in millions):

	Net Loss	Prior Service Credit	Regulatory Deferrals	Total
Pension	$ 58	$ (11)	$ (1)	$ 46
Other postretirement	3	(16)	1	(12)
Total	$ 61	$ (27)	$ —	$ 34

Plan Assumptions

Weighted-average assumptions used to determine benefit obligations and net periodic benefit cost were as follows:

	Pension			Other Postretirement		
	2015	2014	2013	2015	2014	2013
Benefit obligations as of December 31:						
Discount rate	4.43%	4.00%	4.81%	4.33%	3.88%	4.82%
Rate of compensation increase	2.75%	2.75%	3.00%	N/A	N/A	N/A
Net periodic benefit cost for the years ended December 31:						
Discount rate	4.00%	4.81%	4.03%	3.93%	4.82%	4.01%
Expected return on plan assets	6.88%	6.86%	7.50%	7.00%	7.34%	7.44%
Rate of compensation increase	2.75%	3.00%	3.00%	N/A	N/A	N/A

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

	2015	2014
Assumed healthcare cost trend rates as of December 31:		
Healthcare cost trend rate assumed for next year	7.70%	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	2025

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

	One Percentage-Point	
	Increase	Decrease
Increase (decrease) in:		
Total service and interest cost for the year ended December 31, 2015	$ 1	$ (1)
Other postretirement benefit obligation as of December 31, 2015	5	(5)

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be $34 million and $1 million, respectively, during 2016. Funding to the established pension trusts is based upon the actuarially determined costs of the plans and the requirements of the Internal Revenue Code, the Employee Retirement Income Security Act of 1974 and the Pension Protection Act of 2006, as amended. The Company considers contributing additional amounts from time to time in order to achieve certain funding levels specified under the Pension Protection Act of 2006, as amended. The Company's funding policy for its other postretirement benefit plans is to generally contribute an amount equal to the net periodic benefit cost.

The expected benefit payments to participants in the Company's pension and other postretirement benefit plans for 2016 through 2020 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments	
	Pension	Other Postretirement
2016	$ 221	$ 56
2017	224	57
2018	226	58
2019	224	58
2020	225	61
2021-2025	1,054	272

Plan Assets

Investment Policy and Asset Allocations

The Company'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 each plan's Pension and Employee Benefits Plans Administrative 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 the Company's pension and other postretirement benefit plan assets are as follows as of December 31, 2015:

	Pension	Other Postretirement
	%	%
PacifiCorp:		
Debt securities[(1)]	33-37	33-37
Equity securities[(1)]	53-57	61-65
Limited partnership interests	8-12	1-3
Other	0-1	0-1
MidAmerican Energy:		
Debt securities[(1)]	20-40	25-45
Equity securities[(1)]	60-80	50-80
Real estate funds	2-8	—
Other	0-5	0-5
NV Energy:		
Debt securities[(1)]	53-77	40
Equity securities[(1)]	23-47	60

(1) 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 the Company's defined benefit pension plans (in millions):

	Input Levels for Fair Value Measurements[1] Level 1	Level 2	Level 3	Total
As of December 31, 2015				
Cash equivalents	$ —	$ 31	$ —	$ 31
Debt securities:				
United States government obligations	155	—	—	155
International government obligations	—	4	—	4
Corporate obligations	—	335	—	335
Municipal obligations	—	25	—	25
Agency, asset and mortgage-backed obligations	—	154	—	154
Equity securities:				
United States companies	586	—	—	586
International companies	122	—	—	122
Investment funds[2]	144	821	—	965
Limited partnership interests[3]	—	—	65	65
Real estate funds	—	—	47	47
Total	$ 1,007	$ 1,370	$ 112	$ 2,489
As of December 31, 2014				
Cash equivalents	$ 15	$ 54	$ —	$ 69
Debt securities:				
United States government obligations	166	—	—	166
International government obligations	—	11	—	11
Corporate obligations	—	268	—	268
Municipal obligations	—	27	—	27
Agency, asset and mortgage-backed obligations	—	94	—	94
Equity securities:				
United States companies	698	—	—	698
International companies	122	—	—	122
Investment funds[2]	301	852	—	1,153
Limited partnership interests[3]	—	—	70	70
Real estate funds	—	—	40	40
Total	$ 1,302	$ 1,306	$ 110	$ 2,718

(1) Refer to Note 15 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds are comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 66% and 34%, respectively, for 2015 and 61% and 39%, respectively, for 2014. Additionally, these funds are invested in United States and international securities of approximately 58% and 42%, respectively, for 2015 and 64% and 36%, respectively, for 2014.

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

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

	Input Levels for Fair Value Measurements[1]			
	Level 1	Level 2	Level 3	Total
As of December 31, 2015				
Cash equivalents[2]	$ 12	$ 2	$ —	$ 14
Debt securities:				
United States government obligations	18	—	—	18
Corporate obligations	—	33	—	33
Municipal obligations	—	41	—	41
Agency, asset and mortgage-backed obligations	—	28	—	28
Equity securities:				
United States companies	216	—	—	216
International companies	6	—	—	6
Investment funds[3]	149	153	—	302
Limited partnership interests[4]	—	—	4	4
Total	$ 401	$ 257	$ 4	$ 662
As of December 31, 2014				
Cash equivalents	$ 145	$ 1	$ —	$ 146
Debt securities:				
United States government obligations	17	—	—	17
Corporate obligations	—	34	—	34
Municipal obligations	—	43	—	43
Agency, asset and mortgage-backed obligations	—	31	—	31
Equity securities:				
United States companies	243	—	—	243
International companies	6	—	—	6
Investment funds[3]	202	131	—	333
Limited partnership interests[4]	—	—	5	5
Total	$ 613	$ 240	$ 5	$ 858

(1) Refer to Note 15 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 a fund managed by the UMWA in May 2015 as a result of the other postretirement settlement. Remaining investments were rebalanced to align to PacifiCorp's target investment allocations.

(3) Investment funds are comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 63% and 37%, respectively, for 2015 and 63% and 37%, respectively, for 2014. Additionally, these funds are invested in United States and international securities of approximately 70% and 30%, respectively, for 2015 and 69% and 31%, respectively, for 2014.

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

When available, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value. In the absence of a quoted market price or net asset value of an identical security, the fair value is determined using pricing models or net asset values based on observable market inputs and quoted market prices of securities with similar characteristics. When observable market data is not available, the fair value is determined using unobservable inputs, such as estimated future cash flows, purchase multiples paid in other comparable third-party transactions or other information. Investments in limited partnerships are valued at estimated fair value based on the Plan's proportionate share of the partnerships' fair value as recorded in the partnerships' most recently available financial statements adjusted for recent activity and forecasted returns. The fair values recorded in the partnerships' financial statements are generally determined based on closing public market prices for publicly traded securities and as determined by the general partners for other investments based on factors including estimated future cash flows, purchase multiples paid in other comparable third-party transactions, comparable public company trading multiples and other information. The real estate funds determine fair value of their underlying assets using independent appraisals given there is no current liquid market for the underlying assets.

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

	Pension		Other Postretirement-
	Limited Partnership Interests	Real Estate Funds	Limited Partnership Interests
Balance, December 31, 2012	$ 96	$ 26	$ 7
Actual return on plan assets still held at period end	16	5	1
Purchases, sales, distributions and settlements	(26)	—	(2)
Balance, December 31, 2013	86	31	6
Actual return on plan assets still held at period end	(1)	4	—
Purchases, sales, distributions and settlements	(15)	5	(1)
Balance, December 31, 2014	70	40	5
Actual return on plan assets still held at period end	5	7	—
Purchases, sales, distributions and settlements	(10)	—	(1)
Balance, December 31, 2015	$ 65	$ 47	$ 4

Foreign Operations

Certain wholly-owned subsidiaries of Northern Powergrid participate in the Northern Powergrid group of the United Kingdom industry-wide Electricity Supply Pension Scheme (the "UK Plan"), which provides pension and other related defined benefits, based on final pensionable pay, to the majority of the employees of Northern Powergrid. The UK Plan is closed to employees hired after July 23, 1997. Employees hired after that date are covered by a defined contribution plan sponsored by a wholly-owned subsidiary of Northern Powergrid.

Net Periodic Benefit Cost

For purposes of calculating the expected return on pension 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 UK Plan included the following components for the years ended December 31 (in millions):

	2015	2014	2013
Service cost	$ 24	$ 24	$ 22
Interest cost	79	95	85
Expected return on plan assets	(116)	(124)	(101)
Net amortization	62	51	53
Net periodic benefit cost	$ 49	$ 46	$ 59

Funded Status

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

	2015	2014
Plan assets at fair value, beginning of year	$ 2,368	$ 2,177
Employer contributions	77	89
Participant contributions	2	2
Actual return on plan assets	48	337
Benefits paid	(91)	(92)
Foreign currency exchange rate changes	(128)	(145)
Plan assets at fair value, end of year	$ 2,276	$ 2,368

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

	2015	2014
Benefit obligation, beginning of year	$ 2,279	$ 2,185
Service cost	24	24
Interest cost	79	95
Participant contributions	2	2
Actuarial (gain) loss	(30)	205
Benefits paid	(91)	(92)
Foreign currency exchange rate changes	(121)	(140)
Benefit obligation, end of year	$ 2,142	$ 2,279
Accumulated benefit obligation, end of year	$ 1,891	$ 2,019

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

	2015	2014
Plan assets at fair value, end of year	$ 2,276	$ 2,368
Benefit obligation, end of year	2,142	2,279
Funded status	$ 134	$ 89
Amounts recognized on the Consolidated Balance Sheets:		
Other assets	$ 134	$ 89

Unrecognized Amounts

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

	2015	2014
Net loss	$ 592	$ 655

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost, which are included in accumulated other comprehensive loss on the Consolidated Balance Sheets, for the years ended December 31 is as follows (in millions):

	2015	2014
Balance, beginning of year	$ 655	$ 751
Net loss (gain) arising during the year	38	(8)
Net amortization	(62)	(51)
Foreign currency exchange rate changes	(39)	(37)
Total	(63)	(96)
Balance, end of year	$ 592	$ 655

The net loss that will be amortized from accumulated other comprehensive loss in 2016 into net periodic benefit cost is estimated to be $48 million.

Plan Assumptions

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

	2015	2014	2013
Benefit obligations as of December 31:			
Discount rate	3.70%	3.60%	4.40%
Rate of compensation increase	2.90%	2.80%	3.15%
Rate of future price inflation	2.90%	2.80%	3.15%
Net periodic benefit cost for the years ended December 31:			
Discount rate	3.60%	4.40%	4.40%
Expected return on plan assets	5.60%	6.10%	5.70%
Rate of compensation increase	2.80%	3.15%	2.80%
Rate of future price inflation	2.80%	3.15%	2.80%

Contributions and Benefit Payments

Employer contributions to the UK Plan are expected to be £40 million during 2016. The expected benefit payments to participants in the UK Plan for 2016 through 2020 and for the five years thereafter, using the foreign currency exchange rate as of December 31, 2015, are summarized below (in millions):

2016	$ 88
2017	90
2018	92
2019	95
2020	97
2021-2025	522

Plan Assets

Investment Policy and Asset Allocations

The investment policy for the UK Plan is to balance risk and return through a diversified portfolio of debt securities, equity securities and real estate. Maturities for debt securities are managed to targets consistent with prudent risk tolerances. The UK Plan retains outside investment advisors to manage plan investments within the parameters set by the trustees of the UK Plan in consultation with Northern Powergrid. The investment portfolio is managed in line with the investment policy with sufficient liquidity to meet near-term benefit payments. The return on assets assumption is based on a weighted-average of the expected historical performance for the types of assets in which the UK Plan invests.

The target allocations (percentage of plan assets) for the UK Plan assets are as follows as of December 31, 2015:

	%
Debt securities[1]	50-55
Equity securities[1]	35-40
Real estate funds and other	5-15

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

Fair Value Measurements

The following table presents the fair value of the UK Plan assets, by major category, (in millions):

	Input Levels for Fair Value Measurements[1]			
	Level 1	Level 2	Level 3	Total
As of December 31, 2015				
Cash equivalents	$ 46	$ —	$ —	$ 46
Debt securities:				
United Kingdom government obligations	424	—	—	424
Other international government obligations	—	13	—	13
Corporate obligations	—	186	—	186
Investment funds[2]	109	1,294	—	1,403
Real estate funds	—	—	204	204
Total	$ 579	$ 1,493	$ 204	$ 2,276
As of December 31, 2014				
Cash equivalents	$ 43	$ —	$ —	$ 43
Debt securities:				
United States government obligations	—	—	—	—
United Kingdom government obligations	452	—	—	452
Other international government obligations	—	14	—	14
Corporate obligations	—	196	—	196
Investment funds[2]	114	1,350	—	1,464
Real estate funds	—	—	199	199
Total	$ 609	$ 1,560	$ 199	$ 2,368

(1) Refer to Note 15 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds are comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 44% and 56% for both 2015 and 2014.

The fair value of the UK Plan's assets are determined similar to the plan assets of the domestic plans as previously discussed.

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

	Real Estate Funds		
	2015	2014	2013
Beginning balance	$ 199	$ 179	$ 163
Actual return on plan assets still held at period end	18	33	12
Foreign currency exchange rate changes	(13)	(13)	4
Ending balance	$ 204	$ 199	$ 179

Defined Contribution Plans

The Company sponsors various defined contribution plans covering substantially all employees. The Company's contributions vary depending on the plan, but matching contributions are based on each participant's level of contribution, and certain participants receive contributions based on eligible pre-tax annual compensation. Contributions cannot exceed the maximum allowable for tax purposes. The Company's contributions to these plans were $90 million, $83 million and $63 million for the years ended December 31, 2015, 2014 and 2013, respectively.

(13) Asset Retirement Obligations

The Company 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.

The Company 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 generation, 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. These accruals totaled $2.2 billion as of December 31, 2015 and 2014, respectively.

The following table presents the Company's ARO liabilities by asset type as of December 31 (in millions):

	2015	2014
Fossil fuel facilities	$ 443	$ 334
Quad Cities Station	289	265
Wind generating facilities	104	75
Offshore pipeline facilities	31	31
Solar generating facilities	12	9
Other	42	39
Total asset retirement obligations	$ 921	$ 753
Quad Cities Station nuclear decommissioning trust funds	$ 429	$ 424

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

	2015	2014
Beginning balance	$ 753	$ 696
Acquisitions	—	12
Change in estimated costs	104	3
Additions	59	15
Retirements	(32)	(8)
Accretion	37	35
Ending balance	$ 921	$ 753
Reflected as:		
Other current liabilities	$ 92	$ 66
Other long-term liabilities	829	687
Total ARO liability	$ 921	$ 753

The Nuclear Regulatory Commission regulates the decommissioning of nuclear power plants, which includes the planning and funding for the decommissioning. In accordance with these regulations, MidAmerican Energy submits a biennial report to the Nuclear Regulatory Commission providing reasonable assurance that funds will be available to pay for its share of the Quad Cities Station decommissioning. The decommissioning costs are included in base rates in MidAmerican Energy's Iowa tariffs.

Certain of the Company's decommissioning and reclamation obligations relate to jointly owned facilities and mine sites, and as such, each subsidiary 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, the respective subsidiary may be obligated to absorb, directly or by paying additional sums to the entity, a proportionate share of the defaulting party's liability. The Company's estimated share of the decommissioning and reclamation obligations are primarily recorded as ARO liabilities.

The 2015 change in estimated costs is primarily due to changes in the amount and timing of cash flows related to the implementation of the United States Environmental Protection Agency's 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 was published in the Federal Register in April 2015 and was effective in October 2015. In addition to substantially impacting existing AROs, the final rule also resulted in the recognition of additional AROs.

(14) Risk Management and Hedging Activities

The Company is exposed to the impact of market fluctuations in commodity prices, interest rates and foreign currency exchange rates. The Company is principally exposed to electricity, natural gas, coal and fuel oil commodity price risk primarily through BHE's ownership of the Utilities as they have an obligation to serve retail customer load in their regulated service territories. The Company also provides nonregulated retail electricity and natural gas services in competitive markets. The Utilities' 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, wholesale electricity that is purchased and sold, and natural gas supply for retail customers. 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, future debt issuances and mortgage commitments. Additionally, the Company is exposed to foreign currency exchange rate risk from its business operations and investments in Great Britain and Canada. The Company does not engage in a material amount of proprietary trading activities.

Each of the Company's business platforms has established a risk management process that is designed to identify, assess, manage, mitigate, monitor and report each of the various types of risk involved in its business. To mitigate a portion of its commodity price risk, the Company uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. The Company 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, the Company may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, forward sale commitments, or mortgage interest rate lock commitments, to mitigate the Company's exposure to interest rate risk. The Company does not hedge all of its commodity price, interest rate and foreign currency exchange rate risks, thereby exposing the unhedged portion to changes in market prices.

There have been no significant changes in the Company's accounting policies related to derivatives. Refer to Notes 2, 6 and 15 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 the Company'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, 2015					
Not designated as hedging contracts:					
Commodity assets[1]	$ 25	$ 72	$ 7	$ 2	$ 106
Commodity liabilities[1]	(4)	—	(113)	(175)	(292)
Interest rate assets	7	—	—	—	7
Interest rate liabilities	—	—	(3)	(6)	(9)
Total	28	72	(109)	(179)	(188)
Designated as hedging contracts:					
Commodity assets	—	—	1	2	3
Commodity liabilities	—	—	(33)	(17)	(50)
Interest rate assets	—	3	—	—	3
Interest rate liabilities	—	—	(4)	(1)	(5)
Total	—	3	(36)	(16)	(49)
Total derivatives	28	75	(145)	(195)	(237)
Cash collateral receivable	—	—	40	63	103
Total derivatives - net basis	$ 28	$ 75	$ (105)	$ (132)	$ (134)
As of December 31, 2014					
Not designated as hedging contracts:					
Commodity assets[1]	$ 47	$ 66	$ 21	$ 1	$ 135
Commodity liabilities[1]	(11)	—	(146)	(134)	(291)
Interest rate assets	4	—	—	—	4
Interest rate liabilities	—	—	(2)	(4)	(6)
Total	40	66	(127)	(137)	(158)
Designated as hedging contracts:					
Commodity assets	1	—	5	2	8
Commodity liabilities	—	—	(27)	(17)	(44)
Interest rate assets	—	1	—	—	1
Interest rate liabilities	—	—	(4)	—	(4)
Total	1	1	(26)	(15)	(39)
Total derivatives	41	67	(153)	(152)	(197)
Cash collateral receivable	—	—	56	19	75
Total derivatives - net basis	$ 41	$ 67	$ (97)	$ (133)	$ (122)

(1) The Company's commodity derivatives not designated as hedging contracts are generally included in regulated rates, and as of December 31, 2015 and 2014, a net regulatory asset of $250 million and $223 million, respectively, was recorded related to the net derivative liability of $186 million and $156 million, respectively. The difference between the net regulatory asset and the net derivative liability relates primarily to a power purchase agreement derivative at BHE Renewables.

Not Designated as Hedging Contracts

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

	Commodity Derivatives		
	2015	2014	2013
Beginning balance	$ 223	$ 182	$ 235
NV Energy Transaction	—	—	47
Changes in fair value recognized in net regulatory assets	128	96	29
Net gains (losses) reclassified to operating revenue	1	(32)	8
Net losses reclassified to cost of sales	(102)	(23)	(137)
Ending balance	$ 250	$ 223	$ 182

Designated as Hedging Contracts

The Company uses commodity derivative contracts accounted for as cash flow hedges to hedge electricity and natural gas commodity prices for delivery to nonregulated customers, spring operational sales, natural gas storage and other transactions. Certain commodity derivative contracts have settled and the fair value at the date of settlement remains in AOCI and is recognized in earnings when the forecasted transactions impact earnings. The following table reconciles the beginning and ending balances of the Company's AOCI (pre-tax) and summarizes pre-tax gains and losses on commodity derivative contracts designated and qualifying as cash flow hedges recognized in OCI, as well as amounts reclassified to earnings for the years ended December 31 (in millions):

	Commodity Derivatives		
	2015	2014	2013
Beginning balance	$ 32	$ 12	$ 32
Changes in fair value recognized in OCI	52	(6)	(9)
Net gains reclassified to operating revenue	9	—	—
Net (losses) gains reclassified to cost of sales	(47)	26	(11)
Ending balance	$ 46	$ 32	$ 12

Realized gains and losses on hedges and hedge ineffectiveness are recognized in income as operating revenue, cost of sales, operating expense or interest expense depending upon the nature of the item being hedged. For the years ended December 31, 2015, 2014 and 2013, hedge ineffectiveness was insignificant. As of December 31, 2015, the Company had cash flow hedges with expiration dates extending through September 2025 and $36 million of pre-tax unrealized losses are forecasted to be reclassified from AOCI into earnings over the next twelve months as contracts settle.

Derivative Contract Volumes

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

	Unit of Measure	2015	2014
Electricity purchases	Megawatt hours	10	6
Natural gas purchases	Decatherms	317	308
Fuel purchases	Gallons	11	2
Interest rate swaps	US$	653	443
Mortgage sale commitments, net	US$	(312)	(264)

Credit Risk

The Utilities are 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 the Utilities' counterparties have similar economic, industry or other characteristics and due to direct or indirect relationships among the counterparties. Before entering into a transaction, the Utilities analyze the financial condition of each significant wholesale counterparty, establish limits on the amount of unsecured credit to be extended to each counterparty and evaluate the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, the Utilities enter into netting and collateral arrangements that may include margining and cross-product netting agreements and obtain third-party guarantees, letters of credit and cash deposits. If required, the Utilities exercise 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," or in some cases terminate the contract, in the event of a material adverse change in creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2015, the applicable credit ratings from the three recognized credit rating agencies were investment grade.

The aggregate fair value of the Company's derivative contracts in liability positions with specific credit-risk-related contingent features totaled $288 million and $243 million as of December 31, 2015 and 2014, respectively, for which the Company had posted collateral of $75 million and $28 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, 2015 and 2014, the Company would have been required to post $198 million and $182 million, respectively, of additional collateral. The Company's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation, or other factors.

(15) Fair Value Measurements

The carrying value of the Company'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. The Company 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 the Company 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 the Company's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. The Company develops these inputs based on the best information available, including its own data.

The following table presents the Company'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, 2015					
Assets:					
Commodity derivatives	$ —	$ 16	$ 93	$ (16)	$ 93
Interest rate derivatives	—	5	5	—	10
Mortgage loans held for sale	—	327	—	—	327
Money market mutual funds[2]	421	—	—	—	421
Debt securities:					
United States government obligations	133	—	—	—	133
International government obligations	—	2	—	—	2
Corporate obligations	—	39	—	—	39
Municipal obligations	—	1	—	—	1
Agency, asset and mortgage-backed obligations	—	3	—	—	3
Auction rate securities	—	—	44	—	44
Equity securities:					
United States companies	239	—	—	—	239
International companies	1,244	—	—	—	1,244
Investment funds	136	—	—	—	136
	$ 2,173	$ 393	$ 142	$ (16)	$ 2,692
Liabilities:					
Commodity derivatives	$ (13)	$ (283)	$ (46)	$ 119	$ (223)
Interest rate derivatives	—	(13)	(1)	—	(14)
	$ (13)	$ (296)	$ (47)	$ 119	$ (237)
As of December 31, 2014					
Assets:					
Commodity derivatives	$ 1	$ 48	$ 94	$ (40)	$ 103
Interest rate derivatives	—	5	—	—	5
Mortgage loans held for sale	—	279	—	—	279
Money market mutual funds[2]	320	—	—	—	320
Debt securities:					
United States government obligations	136	—	—	—	136
International government obligations	—	1	—	—	1
Corporate obligations	—	39	—	—	39
Municipal obligations	—	2	—	—	2
Agency, asset and mortgage-backed obligations	—	2	—	—	2
Auction rate securities	—	—	45	—	45
Equity securities:					
United States companies	238	—	—	—	238
International companies	886	—	—	—	886
Investment funds	137	—	—	—	137
	$ 1,718	$ 376	$ 139	$ (40)	$ 2,193
Liabilities:					
Commodity derivatives	$ (18)	$ (274)	$ (43)	$ 115	$ (220)
Interest rate derivatives	—	(10)	—	—	(10)
	$ (18)	$ (284)	$ (43)	$ 115	$ (230)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $103 million and $75 million as of December 31, 2015 and 2014, respectively.

(2) Amounts are included in cash and cash equivalents; other current assets; and noncurrent investments and restricted cash and investments 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 the Company transacts. When quoted prices for identical contracts are not available, the Company uses forward price curves. Forward price curves represent the Company's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. The Company bases its forward price curves upon market price quotations, when available, or internally developed and commercial models, with internal and external fundamental data inputs. Market price quotations are obtained from independent brokers, exchanges, direct communication with market participants and actual transactions executed by the Company. Market price quotations are generally readily obtainable for the applicable term of the Company's outstanding derivative contracts; therefore, the Company's forward price curves reflect observable market quotes. Market price quotations for certain electricity and natural gas trading hubs are not as readily obtainable due to the length of the contract. Given that limited market data exists for these contracts, as well as for those contracts that are not actively traded, the Company 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 14 for further discussion regarding the Company's risk management and hedging activities.

The Company's mortgage loans held for sale are valued based on independent quoted market prices, where available, or the prices of other mortgage whole loans with similar characteristics. As necessary, these prices are adjusted for typical securitization activities, including servicing value, portfolio composition, market conditions and liquidity.

The Company's investments in money market mutual funds and debt and equity securities are stated at fair value and are primarily accounted for as available-for-sale securities. When available, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value. In the absence of a quoted market price or net asset value of an identical security, the fair value is determined using pricing models or net asset values based on observable market inputs and quoted market prices of securities with similar characteristics. The fair value of the Company's investments in auction rate securities, where there is no current liquid market, is determined using pricing models based on available observable market data and the Company's judgment about the assumptions, including liquidity and nonperformance risks, which market participants would use when pricing the asset.

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

	Commodity Derivatives			Interest Rate Derivatives			Auction Rate Securities		
	2015	2014	2013	2015	2014	2013	2015	2014	2013
Beginning balance	$ 51	$ 60	$ 32	$ —	$ —	$ —	$ 45	$ 44	$ 41
Changes included in earnings	19	19	34	87	—	—	—	—	—
Changes in fair value recognized in OCI	(7)	—	(2)	—	—	—	(1)	1	3
Changes in fair value recognized in net regulatory assets	(19)	5	1	—	—	—	—	—	—
Purchases	1	1	4	—	—	—	—	—	—
Settlements	2	1	(9)	(86)	—	—	—	—	—
Transfers from Level 2	—	(35)	—	3	—	—	—	—	—
Ending balance	$ 47	$ 51	$ 60	$ 4	$ —	$ —	$ 44	$ 45	$ 44

The Company's long-term debt is carried at cost on the Consolidated Financial Statements. The fair value of the Company'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 the Company'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 the Company's long-term debt as of December 31 (in millions):

	2015		2014	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 37,972	$ 41,785	$ 38,649	$ 43,863

(16) Commitments and Contingencies

Legal Matters

The Company is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. The Company does not believe that such normal and routine litigation will have a material impact on its consolidated financial results. The Company 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. After considering various motions filed by the parties to expand or limit damages, interest and attorney's fees, in May 2013, the court entered a final judgment 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 were heard in September 2015. As of December 31, 2015, PacifiCorp had accrued $122 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.

Commitments

The Company has the following firm commitments that are not reflected on the Consolidated Balance Sheet. Minimum payments as of December 31, 2015 are as follows (in millions):

	2016	2017	2018	2019	2020	2021 and Thereafter	Total
Contract type:							
Fuel, capacity and transmission contract commitments	$ 2,214	$ 1,760	$ 1,345	$ 1,229	$ 1,129	$ 9,494	$ 17,171
Construction commitments	1,544	25	11	3	3	5	1,591
Operating leases and easements	143	118	95	77	66	1,007	1,506
Maintenance, service and other contracts	181	264	180	188	156	805	1,774
	$ 4,082	$ 2,167	$ 1,631	$ 1,497	$ 1,354	$ 11,311	$ 22,042

Fuel, Capacity and Transmission Contract Commitments

The Utilities have fuel supply and related transportation and lime contracts for their coal- and natural gas-fueled generating facilities. The Utilities expect to supplement these contracts with additional contracts and spot market purchases to fulfill their future fossil fuel needs. The Utilities acquire a portion of their electricity through long-term purchases and exchange agreements. The Utilities have 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. The Utilities also have contracts for the right to transmit electricity over other entities' transmission lines to facilitate delivery to their customers.

MidAmerican Energy has long-term rail transportation contracts with BNSF Railway Company ("BNSF"), an affiliate company, and Union Pacific Railroad Company for the transportation of coal to all of the MidAmerican Energy-operated coal-fueled generating facilities. For the years ended December 31, 2015, 2014 and 2013, $185 million, $159 million and $174 million, respectively, were incurred for coal transportation services, the majority of which was related to the BNSF agreement.

Construction Commitments

The Company's firm construction commitments reflected in the table above include the following major construction projects:

- BHE Renewables' construction of certain assets that will facilitate the development of up to 472 MW of wind-powered generating facilities in Nebraska and Kansas.
- MidAmerican Energy's construction of wind-powered generating facilities in 2016 and four Multi-Value Projects approved by the Midcontinent Independent System Operator, Inc. for high voltage transmission lines in Iowa and Illinois in 2016 and 2017.
- ALP's investments in directly assigned transmission projects from the AESO.
- PacifiCorp's costs associated with investments in emissions control equipment and certain transmission and distribution projects.

Operating Leases and Easements

The Company has non-cancelable operating leases primarily for office equipment, office space, certain operating facilities, land and rail cars. These leases generally require the Company 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. The Company also has non-cancelable easements for land on which its wind-powered generating facilities are located. Rent expense on non-cancelable operating leases totaled $161 million for 2015, $146 million for 2014 and $118 million for 2013.

Maintenance, Service and Other Contracts

The Company has entered into service agreements related to its nonregulated solar and wind-powered projects with third parties to operate and maintain the projects under fixed-fee operating and maintenance agreements. Additionally, the Company has various non-cancelable maintenance, service and other contracts primarily related to turbine and equipment maintenance and various other service agreements.

Environmental Laws and Regulations

The Company is subject to federal, state, local and foreign 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 the Company's current and future operations. The Company 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 begin 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 is required to provide, among other things, protection for PacifiCorp from all liabilities associated with dam removal activities. As of December 31, 2015, no federal legislation was enacted. In February 2016, the principal parties to the KHSA (PacifiCorp, the states of California and Oregon and the United States Departments of the Interior and Commerce) executed an Agreement in Principle committing to explore potential amendment of the KHSA to facilitate removal of the Klamath dams through a FERC process without the need for federal legislation. Any amendment to the KHSA would ensure that the existing KHSA framework would remain in place, capping PacifiCorp's costs and requiring transfer of the dams to a separate entity that would remove the dams and provide PacifiCorp and its customers with protections against potential dam removal liabilities. If the KHSA is not amended, then PacifiCorp will resume relicensing with the FERC.

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, 2015, PacifiCorp's assets included $81 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, depending upon the state jurisdiction.

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 $252 million over the next 10 years related to these licenses.

Guarantees

The Company 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 the Company's consolidated financial results.

(17) BHE Shareholders' Equity

Common Stock

On March 14, 2000, and as amended on December 7, 2005, BHE's shareholders entered into a Shareholder Agreement that provides specific rights to certain shareholders. One of these rights allows certain shareholders the ability to put their common shares back to BHE at the then current fair value dependent on certain circumstances controlled by BHE.

On December 19, 2013, Berkshire Hathaway and other existing shareholders invested $1.0 billion, in the aggregate, in 2,857,143 shares of BHE's common stock in order to provide equity funding for the NV Energy Transaction (see Note 3). The per-share value assigned to the shares of common stock issued, which were effected pursuant to a private placement and were exempt from the registration requirements of the Securities Act of 1933, as amended, was based on a per share value as agreed to by BHE's shareholders.

On February 17, 2015, BHE repurchased from certain family interests of Mr. Walter Scott, Jr. 75,000 shares of its common stock for $36 million.

Restricted Net Assets

BHE has maximum debt-to-total capitalization percentage restrictions imposed by its senior unsecured credit facilities expiring in June 2017 which, in certain circumstances, limit BHE's ability to make cash dividends or distributions. As a result of this restriction, BHE has restricted net assets of $12.7 billion as of December 31, 2015.

Certain of BHE's subsidiaries have restrictions on their ability to dividend, loan or advance funds to BHE due to specific legal or regulatory restrictions, including, but not limited to, maximum debt-to-total capitalization percentages and commitments made to state commissions or federal agencies in connection with past acquisitions. As a result of these restrictions, BHE's subsidiaries had restricted net assets of $17.2 billion as of December 31, 2015.

(18) Components of Accumulated Other Comprehensive Loss, Net

The following table shows the change in accumulated other comprehensive loss attributable to BHE shareholders by each component of other comprehensive income (loss), net of applicable income taxes, for the year ended December 31, (in millions):

	Unrecognized Amounts on Retirement Benefits	Foreign Currency Translation Adjustment	Unrealized Gains on Available-For-Sale Securities	Unrealized Gains on Cash Flow Hedges	Accumulated Other Comprehensive Loss Attributable To BHE Shareholders, Net
Balance, December 31, 2012	$ (575)	$ (172)	$ 261	$ 23	$ (463)
Other comprehensive income	16	74	263	13	366
Balance, December 31, 2013	(559)	(98)	524	36	(97)
Other comprehensive income (loss)	69	(314)	(134)	(18)	(397)
Balance, December 31, 2014	(490)	(412)	390	18	(494)
Other comprehensive income (loss)	52	(680)	225	(11)	(414)
Balance, December 31, 2015	$ (438)	$ (1,092)	$ 615	$ 7	$ (908)

Reclassifications from AOCI to net income for the years ended December 31, 2015, 2014 and 2013 were insignificant. For information regarding cash flow hedge reclassifications from AOCI to net income in their entirety, refer to Note 14. Additionally, refer to the "Foreign Operations" discussion in Note 12 for information about unrecognized amounts on retirement benefits reclassifications from AOCI that do not impact net income in their entirety.

(19) Noncontrolling Interests

Included in noncontrolling interests on the Consolidated Balance Sheets are preferred securities of subsidiaries of $58 million as of December 31, 2015 and 2014, consisting of $56 million of 8.061% cumulative preferred securities of Northern Electric plc., a subsidiary of Northern Powergrid, which are redeemable in the event of the revocation of Northern Electric plc.'s electricity distribution license by the Secretary of State, and $2 million of nonredeemable preferred stock at PacifiCorp.

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, and MidAmerican Energy redeemed and canceled all outstanding shares of each series of its preferred securities at the stated redemption prices, which in aggregate totaled $28 million including accrued dividends.

(20) Supplemental Cash Flow Disclosures

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

	2015	2014	2013
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	$ 1,764	$ 1,585	$ 1,073
Income taxes received, net[(1)]	$ 1,666	$ 635	$ 1,105
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	$ 718	$ 1,143	$ 661

(1) Includes $1.8 billion, $764 million and $1.2 billion of income taxes received from Berkshire Hathaway in 2015, 2014 and 2013, respectively.

(21) Segment Information

The Company's reportable segments with foreign operations include Northern Powergrid, whose business is principally in the United Kingdom, BHE Transmission, whose business includes operations in Canada, and BHE Renewables, whose business includes operations in the Philippines. Intersegment eliminations and adjustments, including the allocation of goodwill, have been made. Information related to the Company's reportable segments is shown below (in millions):

	Years Ended December 31,		
	2015	2014	2013
Operating revenue:			
PacifiCorp	$ 5,232	$ 5,252	$ 5,147
MidAmerican Funding	3,420	3,762	3,413
NV Energy	3,351	3,241	(20)
Northern Powergrid	1,140	1,283	1,025
BHE Pipeline Group	1,016	1,078	952
BHE Transmission	592	62	—
BHE Renewables	728	623	355
HomeServices	2,526	2,144	1,809
BHE and Other[1]	(125)	(119)	(46)
Total operating revenue	$ 17,880	$ 17,326	$ 12,635
Depreciation and amortization:			
PacifiCorp	$ 780	$ 745	$ 692
MidAmerican Funding	407	351	403
NV Energy	410	379	—
Northern Powergrid	202	198	180
BHE Pipeline Group	204	196	190
BHE Transmission	185	13	—
BHE Renewables	216	152	71
HomeServices	29	29	33
BHE and Other[1]	(5)	(6)	(9)
Total depreciation and amortization	$ 2,428	$ 2,057	$ 1,560
Operating income:			
PacifiCorp	$ 1,344	$ 1,308	$ 1,275
MidAmerican Funding	473	423	357
NV Energy	812	791	(42)
Northern Powergrid	593	674	501
BHE Pipeline Group	464	439	446
BHE Transmission	260	16	(5)
BHE Renewables	255	314	223
HomeServices	184	125	129
BHE and Other[1]	(57)	(44)	(49)
Total operating income	4,328	4,046	2,835
Interest expense	(1,904)	(1,711)	(1,222)
Capitalized interest	74	89	84
Allowance for equity funds	91	98	78
Interest and dividend income	107	38	15
Other, net	39	42	51
Total income before income tax expense and equity income (loss)	$ 2,735	$ 2,602	$ 1,841

	Years Ended December 31,		
	2015	2014	2013
Interest expense:			
PacifiCorp	$ 383	$ 386	$ 390
MidAmerican Funding	206	197	174
NV Energy	262	283	—
Northern Powergrid	145	151	141
BHE Pipeline Group	66	76	80
BHE Transmission	146	14	—
BHE Renewables	193	175	138
HomeServices	3	4	3
BHE and Other(1)	500	425	296
Total interest expense	$ 1,904	$ 1,711	$ 1,222
Income tax expense (benefit):			
PacifiCorp	$ 328	$ 310	$ 298
MidAmerican Funding	(144)	(110)	(110)
NV Energy	207	195	(15)
Northern Powergrid	35	110	23
BHE Pipeline Group	158	149	149
BHE Transmission	63	28	10
BHE Renewables	41	65	57
HomeServices	72	44	48
BHE and Other(1)	(310)	(202)	(330)
Total income tax expense (benefit)	$ 450	$ 589	$ 130
Capital expenditures:			
PacifiCorp	$ 916	$ 1,066	$ 1,065
MidAmerican Funding	1,448	1,527	1,027
NV Energy	571	558	—
Northern Powergrid	674	675	675
BHE Pipeline Group	240	257	177
BHE Transmission	966	222	—
BHE Renewables	1,034	2,221	1,329
HomeServices	16	17	21
BHE and Other	10	12	13
Total capital expenditures	$ 5,875	$ 6,555	$ 4,307

	As of December 31,		
	2015	2014	2013
Property, plant and equipment, net:			
PacifiCorp	$ 19,039	$ 18,755	$ 18,563
MidAmerican Funding	11,737	10,535	9,353
NV Energy	9,767	9,648	9,623
Northern Powergrid	5,790	5,599	5,476
BHE Pipeline Group	4,345	4,286	4,147
BHE Transmission	5,301	5,567	—
BHE Renewables	4,805	4,897	3,020
HomeServices	70	68	61
BHE and Other	(85)	(107)	(124)
Total property, plant and equipment, net	$ 60,769	$ 59,248	$ 50,119
Total assets:			
PacifiCorp	$ 23,550	$ 23,404	$ 22,781
MidAmerican Funding	16,499	15,346	13,970
NV Energy	14,656	14,256	14,016
Northern Powergrid	7,317	7,059	6,852
BHE Pipeline Group	4,953	4,951	4,891
BHE Transmission	7,553	7,979	465
BHE Renewables	5,892	6,082	3,832
HomeServices	1,705	1,622	1,375
BHE and Other	1,493	1,117	1,409
Total assets	$ 83,618	$ 81,816	$ 69,591

	Years Ended December 31,		
	2015	2014	2013
Operating revenue by country:			
United States	$ 16,121	$ 15,857	$ 11,465
United Kingdom	1,140	1,281	1,023
Canada	600	78	16
Philippines and other	19	110	131
Total operating revenue by country	$ 17,880	$ 17,326	$ 12,635
Income before income tax expense and equity income (loss) by country:			
United States	$ 2,034	$ 2,001	$ 1,388
United Kingdom	472	557	373
Canada	165	4	—
Philippines and other	64	40	80
Total income before income tax expense and equity income (loss) by country:	$ 2,735	$ 2,602	$ 1,841

	As of December 31,		
	2015	2014	2013
Property, plant and equipment, net by country:			
United States	$ 49,680	$ 47,918	$ 44,460
United Kingdom	5,757	5,563	5,439
Canada	5,298	5,570	3
Philippines and other	34	197	217
Total property, plant and equipment, net by country	$ 60,769	$ 59,248	$ 50,119

(1) The differences between the reportable segment amounts and the consolidated amounts, described as BHE and Other, relate to other corporate entities, corporate functions and intersegment eliminations.

The following table shows the change in the carrying amount of goodwill by reportable segment for the years ended December 31, 2015 and 2014 (in millions):

	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Pipeline Group	BHE Transmission	BHE Renewables	Home-Services	Other	Total
December 31, 2013	$ 1,129	$ 2,102	$ 2,280	$ 1,149	$ 153	$ —	$ 15	$ 695	$ 4	$7,527
Acquisitions	—	—	89	—	—	1,700	80	66	—	1,935
Foreign currency translation	—	—	—	(49)	—	(43)	—	—	(1)	(93)
Other	—	—	—	—	(26)	—	—	—	—	(26)
December 31, 2014	1,129	2,102	2,369	1,100	127	1,657	95	761	3	9,343
Acquisitions	—	—	—	—	—	44	—	33	—	77
Foreign currency translation	—	—	—	(44)	—	(273)	—	—	(1)	(318)
Other	—	—	—	—	(26)	—	—	—	—	(26)
December 31, 2015	$ 1,129	$ 2,102	$ 2,369	$ 1,056	$ 101	$ 1,428	$ 95	$ 794	$ 2	$9,076

PacifiCorp and its subsidiaries
Consolidated Financial Section

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,				
	2015	2014	2013	2012	2011
Consolidated Statement of Operations Data:					
Operating revenue	$ 5,232	$ 5,252	$ 5,147	$ 4,882	$ 4,586
Operating income	1,340	1,300	1,264	1,021	1,084
Net income	695	698	682	537	555

	As of December 31,				
	2015	2014	2013	2012	2011
Consolidated Balance Sheet Data:					
Total assets(1)(2)	$ 22,367	$ 22,205	$ 21,559	$ 21,581	$ 20,944
Short-term debt	20	20	—	—	688
Current portion of long-term debt and capital lease obligations	68	134	238	267	19
Long-term debt and capital lease obligations, excluding current portion(2)	7,078	6,885	6,605	6,559	6,161
Total shareholders' equity	7,503	7,756	7,787	7,644	7,312

(1) In December 2015, PacifiCorp retrospectively adopted Accounting Standards Update No. 2015-17, which resulted in the reclassification of current deferred income tax assets in the amounts of $28 million, $66 million, $112 million, and $129 million, as of December 31, 2014, 2013, 2012 and 2011, respectively, as reductions in noncurrent deferred income tax liabilities.

(2) In December 2015, PacifiCorp retrospectively adopted Accounting Standards Update 2015-03, which resulted in the reclassification of certain deferred debt issuance costs previously recognized within other assets in the amounts of $34 million, $34 million, $35 million, and $33 million, as of December 31, 2014, 2013, 2012 and 2011, respectively, as reductions in long-term debt.

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, 2015 was $695 million, a decrease of $3 million compared to 2014. Net income decreased due to the prior year recognition of insurance recoveries for a fire claim, higher depreciation and amortization of $31 million, lower AFUDC of $25 million and higher property taxes, partially offset by higher margins of $109 million. Margins increased primarily due to higher retail rates, lower purchased electricity prices, lower natural gas generation and costs, Utah Mine Disposition costs in 2014 and lower coal generation, partially offset by higher purchased electricity volumes, lower wholesale electricity revenue from lower volumes and prices and lower retail customer load. Retail customer load decreased 0.7% due to lower industrial customer usage in Utah and Wyoming and lower residential customer usage across the service territory, partially offset by an increase in the average number of residential customers in Utah and Oregon, an increase in the average number of commercial customers in Utah and the impacts of weather on residential, commercial and irrigation customer loads. Energy generated decreased 6% for 2015 compared to 2014 due to lower availability and dispatch of natural gas-fueled generation and lower hydroelectric and wind-powered generation, partially offset by the addition of Lake Side 2. Wholesale electricity sales volumes decreased 13% and purchased electricity volumes increased 19%.

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 expense, lower operations and maintenance expense as a result of recognition in 2014 of 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%.

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:

	2015	2014	Change		2014	2013	Change	
Gross margin (in millions):								
Operating revenue	$ 5,232	$ 5,252	$ (20)	— %	$ 5,252	$ 5,147	$ 105	2 %
Energy costs	1,868	1,997	(129)	(6)	1,997	1,924	73	4
Gross margin	$ 3,364	$ 3,255	$ 109	3	$ 3,255	$ 3,223	$ 32	1
Sales (GWh):								
Residential	15,566	15,568	(2)	— %	15,568	16,339	(771)	(5)%
Commercial	17,262	17,073	189	1	17,073	17,057	16	—
Industrial and irrigation	21,403	21,934	(531)	(2)	21,934	21,832	102	—
Other	410	424	(14)	(3)	424	435	(11)	(3)
Total retail	54,641	54,999	(358)	(1)	54,999	55,663	(664)	(1)
Wholesale	8,889	10,270	(1,381)	(13)	10,270	10,206	64	1
Total sales	63,530	65,269	(1,739)	(3)	65,269	65,869	(600)	(1)
Average number of retail customers (in thousands)	1,813	1,783	30	2 %	1,783	1,767	16	1 %
Average revenue per MWh:								
Retail	$ 87.99	$ 85.73	$ 2.26	3 %	$ 85.73	$ 83.40	$ 2.33	3 %
Wholesale	$ 29.92	$ 33.94	$ (4.02)	(12)%	$ 33.94	$ 31.40	$ 2.54	8 %
Sources of energy (GWh)(1):								
Coal	41,298	42,218	(920)	(2)%	42,218	43,688	(1,470)	(3)%
Natural gas	9,222	10,881	(1,659)	(15)	10,881	8,176	2,705	33
Hydroelectric(2)	2,914	3,782	(868)	(23)	3,782	3,163	619	20
Wind and other(2)	2,892	3,318	(426)	(13)	3,318	3,353	(35)	(1)
Total energy generated	56,326	60,199	(3,873)	(6)	60,199	58,380	1,819	3
Energy purchased	11,646	9,817	1,829	19	9,817	12,243	(2,426)	(20)
Total	67,972	70,016	(2,044)	(3)	70,016	70,623	(607)	(1)
Average cost of energy per MWh:								
Energy generated(3)	$ 19.38	$ 20.71	$ (1.33)	(6)%	$ 20.71	$ 19.19	$ 1.52	8 %
Energy purchased	$ 49.92	$ 58.56	$ (8.64)	(15)%	$ 58.56	$ 55.16	$ 3.40	6 %

(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 only the cost of fuel associated with the generating facilities.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

Gross margin increased $109 million, or 3%, for 2015 compared to 2014 primarily due to:

- $131 million of lower natural gas costs due to decreased generation, primarily as a result of lower availability and dispatch, and lower average unit costs, partially offset by increased generation from the addition of Lake Side 2;

- $109 million of increases mainly from higher retail rates; and

- $25 million of lower coal costs primarily due to decreased generation, including the idling of the Carbon Facility in April 2015 and Utah Mine Disposition costs in 2014.

The increases above were partially offset by:

- $83 million of lower wholesale revenue due to reduced volumes and lower average wholesale prices;

- $31 million of lower REC revenue primarily due to the effects of established adjustment mechanisms;

- $21 million of lower net deferrals of incurred net power costs in accordance with established adjustment mechanisms;

- $16 million of lower retail revenues from a 0.7% decrease in retail customer load due to 1.8% lower customer usage primarily by industrial customers in Utah and Wyoming and residential customers across the service territory, partially offset by a 0.8% increase in the average number of residential customers in Utah and Oregon and commercial customers in Utah and a 0.3% increase due to the impacts of weather on residential, commercial and irrigation customer loads; and

- $6 million of higher purchased electricity due to higher volumes substantially offset by lower average market prices.

Operations and maintenance increased $25 million, or 2%, for 2015 compared to 2014 primarily due to recognition in 2014 of insurance recoveries expected from the Sanpete County, Utah rangeland fire and higher chemical costs from mercury control equipment installed in early 2015, partially offset by lower labor and benefit costs. 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 $31 million, or 4%, for 2015 compared to 2014 primarily due to higher plant in-service, including Lake Side 2.

Taxes, other than income taxes increased $13 million, or 8%, for 2015 compared to 2014 due to higher property taxes primarily from higher assessed property values and higher plant in-service.

Allowance for borrowed and equity funds decreased $25 million, or 33%, for 2015 compared to 2014 due to lower qualified construction work-in-progress balances and lower rates.

Income tax expense increased $19 million, or 6%, for 2015 compared to 2014 and the effective tax rate was 32% and 31% for 2015 and 2014, respectively. The increase in income tax expense was primarily due to lower production tax credits associated with PacifiCorp's wind-powered generating facilities and higher pre-tax book income.

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 increases above were 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, 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 recognition in 2014 of insurance recoveries expected from the Sanpete County, Utah rangeland fire and related charges in 2013.

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.

Liquidity and Capital Resources

As of December 31, 2015, PacifiCorp's total net liquidity was as follows (in millions):

Cash and cash equivalents	$	12
Credit facilities[1]		1,200
Less:		
Short-term debt		(20)
Tax-exempt bond support and letters of credit		(160)
Net credit facilities		1,020
Total net liquidity	$	1,032
Credit facilities:		
Maturity dates		2017, 2018

(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, 2015 and 2014 were $1.734 billion and $1.570 billion, respectively. The $164 million increase was primarily due to lower cash paid for income taxes, lower fuel and purchased electricity payments and partial insurance recovery for Sanpete County, Utah rangeland fire costs incurred, partially offset by lower receipts from wholesale electricity sales and increases in cash collateral posted for derivative contracts.

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 benefited in 2015 due to bonus depreciation on qualifying assets placed in-service.

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.

The timing of PacifiCorp's income tax cash flows from period to period can be significantly affected by the estimated federal income tax payment methods and assumptions for each payment date.

Investing Activities

Net cash flows from investing activities for the years ended December 31, 2015 and 2014 were $(918) million and $(1.079) billion, respectively. The change was primarily due to a decrease in capital expenditures of $150 million. Refer to "Future Uses of Cash" for discussion of capital expenditures.

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.

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, 2015 and 2014 at a weighted average interest rate of 0.65% and 0.43%, respectively. 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 June 2015, PacifiCorp issued $250 million of its 3.35% First Mortgage Bonds due July 2025. The net proceeds were used to fund capital expenditures and for general corporate purposes, including retirement of short-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.

PacifiCorp currently has regulatory authority from the OPUC and the IPUC to issue an additional $1.325 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 with the SEC to issue up to $1.325 billion additional first mortgage bonds through January 2019.

PacifiCorp made repayments on long-term debt totaling $122 million and $236 million during the years ended December 31, 2015 and 2014, respectively.

As of December 31, 2015, PacifiCorp had $310 million of letters of credit providing credit enhancement and liquidity support for variable-rate tax-exempt bond obligations totaling $305 million plus interest. These letters of credit were fully available as of December 31, 2015 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, 2015, PacifiCorp estimated it would be able to issue up to $9.3 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.

Preferred Stock

As of December 31, 2015 and 2014, PacifiCorp had non-redeemable preferred stock outstanding with an aggregate stated value of $2 million.

Common Shareholder's Equity

In February 2016, PacifiCorp declared a dividend of $100 million payable to PPW Holdings LLC in March 2016.

In 2015 and 2014, PacifiCorp declared and paid dividends of $950 million and $725 million, respectively, to PPW Holdings LLC.

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.

Historical and forecast 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			Forecast		
	2013	2014	2015	2016	2017	2018
Transmission system investment	$ 278	$ 262	$ 137	$ 87	$ 124	$ 104
Environmental	57	158	114	59	28	33
Lake Side 2	156	37	—	—	—	—
Operating and other	574	609	665	649	628	709
Total	$ 1,065	$ 1,066	$ 916	$ 795	$ 780	$ 846

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

- Transmission system investment includes construction costs for the 170-mile single-circuit 345-kV Sigurd-Red Butte transmission line that was placed in-service in May 2015. PacifiCorp anticipates costs for transmission system investments will total $315 million between 2016 and 2018, primarily for main grid reinforcement and development costs for certain projects associated with the Energy Gateway Transmission Expansion Program.

- Environmental includes the installation of new or the replacement of existing emissions control equipment at certain generating facilities, including installation or upgrade of selective catalytic reduction control systems, low-nitrogen oxide burners to reduce nitrogen oxides and mercury emissions control systems. Additional projects address coal combustion residuals and anticipated effluent limitation compliance. PacifiCorp anticipates costs for environmental projects will total $120 million between 2016 and 2018, primarily for selective catalytic reduction control systems at Jim Bridger Unit 4 and Craig Unit 2, and expenditures for management of coal combustion residuals.

- 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, 2015 (in millions):

	Payments Due By Periods				
	2016	2017-2018	2019-2020	2021 and Thereafter	Total
Long-term debt, including interest:					
Fixed-rate obligations	$ 359	$ 1,212	$ 974	$ 9,614	$ 12,159
Variable-rate obligations(1)	63	136	38	219	456
Capital leases, including interest	5	15	9	27	56
Operating leases and easements	5	8	8	42	63
Asset retirement obligations	35	27	28	368	458
Power purchase agreements - commercially operable(2):					
Electricity commodity contracts	108	60	60	157	385
Electricity capacity contracts	54	69	65	215	403
Electricity mixed contracts	6	12	10	29	57
Power purchase agreements - non-commercially operable(2)	16	206	208	1,687	2,117
Transmission	105	188	131	508	932
Fuel purchase agreements(2):					
Natural gas supply and transportation	83	54	52	283	472
Coal supply and transportation	779	1,193	986	1,437	4,395
Other purchase obligations	180	71	39	79	369
Other long-term liabilities(3)	11	11	11	54	87
Total contractual cash obligations	$ 1,809	$ 3,262	$ 2,619	$ 14,719	$ 22,409

(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, 2015 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. Refer to the discussion contained in Item 1 of this Form 10-K for further discussion regarding PacifiCorp's general regulatory framework and current regulatory matters.

Environmental Laws and Regulations

PacifiCorp is subject to federal, state, local and foreign 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, local and international 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. 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 financial results.

Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for additional information regarding environmental laws and regulations and "Liquidity and Capital Resources" for PacifiCorp's forecast environmental-related capital expenditures.

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, 2015, 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, 2015, PacifiCorp would have been required to post $261 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 $6.7 billion as of December 31, 2015 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, 2015, the most restrictive of these commitments prohibits PacifiCorp from making any distribution to PPW Holdings LLC 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, 2015, PacifiCorp's actual common stock equity percentage, as calculated under this measure, was 52%, and management believes that PacifiCorp could have declared a dividend of $2.0 billion under this commitment.

These commitments also restrict PacifiCorp from making any distributions to either PPW Holdings LLC 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, 2015, 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 through the use of energy and other cost adjustment clauses and bill riders, 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). Total regulatory assets were $1.685 billion and total regulatory liabilities were $972 million as of December 31, 2015. 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, 2015, 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, 2015, PacifiCorp had a net derivative liability of $139 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, 2015, PacifiCorp had a net derivative asset of $3 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, 2015, PacifiCorp had $133 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 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, 2015, PacifiCorp recognized a net liability totaling $303 million for the funded status of its defined benefit pension and other postretirement benefit plans. As of December 31, 2015, amounts not yet recognized as a component of net periodic benefit cost that were included in regulatory assets and accumulated other comprehensive loss totaled $499 million and $19 million, respectively.

The expense and benefit obligations relating to these defined benefit pension and other postretirement benefit plans are based on actuarial valuations. Inherent in these valuations are key assumptions, including discount rates and expected long-term rate of return on plan assets. 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, 2015.

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.

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, 2015 Benefit Obligations:				
Discount rate	$ (66)	$ 73	$ (15)	$ 17
Effect on 2015 Periodic Cost:				
Discount rate	$ (4)	$ 4	$ —	$ —
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, 2015, these amounts were recognized as a regulatory asset of $437 million and a regulatory liability of $12 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 $245 million as of December 31, 2015. 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 commodity 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, 2015, 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 $7 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):

		2015
Minimum VaR (measured)	$	6
Average VaR (calculated)		9
Maximum VaR (measured)		12

PacifiCorp maintained compliance with its VaR limit procedures during the year ended December 31, 2015. 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 $75 million and $28 million as of December 31, 2015 and 2014, 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, 2015:			
Total commodity derivative contracts	$ (136)	$ (103)	$ (169)
As of December 31, 2014:			
Total commodity derivative contracts	$ (85)	$ (49)	$ (121)

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, 2015 and 2014, a regulatory asset of $133 million and $85 million, respectively, was recorded related to the net derivative liability of $136 million and $85 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, 2015 and 2014, PacifiCorp had short- and long-term variable-rate obligations totaling $475 million and $591 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, 2015 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, 2015 and 2014.

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, 2015, PacifiCorp's aggregate credit exposure from wholesale activities totaled $124 million, based on settlement and mark-to-market exposures, net of collateral. As of December 31, 2015, $123 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, 2015, two counterparties comprised $94 million, or 75%, 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, 2015.

Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets of PacifiCorp and subsidiaries ("PacifiCorp") as of December 31, 2015 and 2014, 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, 2015. These financial statements are the responsibility of PacifiCorp'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. PacifiCorp 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 PacifiCorp'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, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 26, 2016

PACIFICORP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2015	2014
ASSETS		
Current assets:		
Cash and cash equivalents	$ 12	$ 23
Accounts receivable, net	740	701
Income taxes receivable	17	133
Inventories:		
Materials and supplies	233	218
Fuel	192	199
Regulatory assets	102	131
Other current assets	81	92
Total current assets	1,377	1,497
Property, plant and equipment, net	19,026	18,719
Regulatory assets	1,583	1,574
Other assets	381	415
Total assets	$ 22,367	$ 22,205

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,	
	2015	**2014**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 473	$ 465
Accrued employee expenses	70	76
Accrued interest	115	110
Accrued property and other taxes	62	59
Short-term debt	20	20
Current portion of long-term debt and capital lease obligations	68	134
Regulatory liabilities	34	34
Other current liabilities	229	222
Total current liabilities	1,071	1,120
Regulatory liabilities	938	910
Long-term debt and capital lease obligations	7,078	6,885
Deferred income taxes	4,750	4,581
Other long-term liabilities	1,027	953
Total liabilities	14,864	14,449
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	3,033	3,288
Accumulated other comprehensive loss, net	(11)	(13)
Total shareholders' equity	7,503	7,756
Total liabilities and shareholders' equity	$ 22,367	$ 22,205

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,		
	2015	2014	2013
Operating revenue	$ 5,232	$ 5,252	$ 5,147
Operating costs and expenses:			
Energy costs	1,868	1,997	1,924
Operations and maintenance	1,082	1,057	1,114
Depreciation and amortization	757	726	675
Taxes, other than income taxes	185	172	170
Total operating costs and expenses	3,892	3,952	3,883
Operating income	1,340	1,300	1,264
Other income (expense):			
Interest expense	(379)	(379)	(379)
Allowance for borrowed funds	18	25	29
Allowance for equity funds	33	51	57
Other, net	11	10	8
Total other income (expense)	(317)	(293)	(285)
Income before income tax expense	1,023	1,007	979
Income tax expense	328	309	297
Net income	$ 695	$ 698	$ 682

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,		
	2015	**2014**	**2013**
Net income	$ 695	$ 698	$ 682
Other comprehensive income (loss), net of tax —			
Unrecognized amounts on retirement benefits, net of tax of $1, $(3) and $1	2	(4)	3
Comprehensive income	$ 697	$ 694	$ 685

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, 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
Net income	—	—	—	695	—	695
Other comprehensive income	—	—	—	—	2	2
Common stock dividends declared	—	—	—	(950)	—	(950)
Balance, December 31, 2015	$ 2	$ —	$ 4,479	$ 3,033	$ (11)	$ 7,503

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,		
	2015	**2014**	**2013**
Cash flows from operating activities:			
Net income	$ 695	$ 698	$ 682
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	757	726	675
Allowance for equity funds	(33)	(51)	(57)
Deferred income taxes and amortization of investment tax credits	172	297	230
Changes in regulatory assets and liabilities	63	(112)	(32)
Other, net	6	22	21
Changes in other operating assets and liabilities:			
Accounts receivable and other assets	5	5	(7)
Derivative collateral, net	(47)	(16)	43
Inventories	(7)	37	14
Income taxes	116	(155)	(26)
Accounts payable and other liabilities	7	119	10
Net cash flows from operating activities	1,734	1,570	1,553
Cash flows from investing activities:			
Capital expenditures	(916)	(1,066)	(1,065)
Other, net	(2)	(13)	16
Net cash flows from investing activities	(918)	(1,079)	(1,049)
Cash flows from financing activities:			
Proceeds from long-term debt	248	422	297
Repayments of long-term debt and capital lease obligations	(124)	(238)	(284)
Net proceeds from short-term debt	—	20	—
Redemption of preferred stock	—	—	(40)
Common stock dividends	(950)	(725)	(500)
Preferred stock dividends	—	—	(2)
Other, net	(1)	—	(2)
Net cash flows from financing activities	(827)	(521)	(531)
Net change in cash and cash equivalents	(11)	(30)	(27)
Cash and cash equivalents at beginning of period	23	53	80
Cash and cash equivalents at end of period	$ 12	$ 23	$ 53

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

PACIFICORP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Organization and Operations

PacifiCorp, which includes PacifiCorp and its subsidiaries, is a United States regulated electric 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, 2015 and 2014, PacifiCorp had no unrealized gains and losses on available-for-sale securities. Trading securities are carried at fair value with realized and unrealized gains and losses recognized in earnings.

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):

	2015	2014	2013
Beginning balance	$ 7	$ 8	$ 9
Charged to operating costs and expenses, net	10	11	13
Write-offs, net	(10)	(12)	(14)
Ending balance	$ 7	$ 7	$ 8

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 net realizable value.

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, 2015 and 2014, unbilled revenue was $245 million and $243 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 $437 million and $446 million as of December 31, 2015 and 2014, respectively, and regulatory liabilities of $12 million and $13 million as of December 31, 2015 and 2014, 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 $23 million and $27 million as of December 31, 2015 and 2014, 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 January 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2016-01, which amends FASB Accounting Standards Codification ("ASC") Subtopic 825-10, "Financial Instruments - Overall." The amendments in this guidance address certain aspects of recognition, measurement, presentation and disclosure of financial instruments including a requirement that all investments in equity securities that do not qualify for equity method accounting or result in consolidation of the investee be measured at fair value with changes in fair value recognized in net income. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption not permitted, and is required to be adopted prospectively by means of a cumulative-effect adjustment to the balance sheet as of the beginning of the fiscal year of adoption. 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 November 2015, the FASB issued ASU No. 2015-17, which amends ASC Topic 740, "Income Taxes". The amendments in this guidance require that deferred income tax liabilities and assets be classified as noncurrent in the balance sheet. This guidance is effective for interim and annual reporting periods beginning after December 15, 2016, with early adoption permitted, and may be adopted prospectively or retrospectively for each period presented to reflect the new guidance. PacifiCorp early adopted this guidance as of December 31, 2015 under a retrospective method, resulting in decreases in current deferred income tax assets of $28 million and noncurrent deferred income tax liabilities of $28 million as of December 31, 2014.

In April 2015, the FASB issued ASU No. 2015-03, which amends FASB ASC Subtopic 835-30, "Interest - Imputation of Interest." The amendments in this guidance require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability instead of as an asset. This guidance is effective for interim and annual reporting periods beginning after December 15, 2015, with early adoption permitted, and must be adopted retrospectively for each period presented to reflect the new guidance. PacifiCorp early adopted this guidance as of December 31, 2015 under a retrospective method, resulting in a decrease in other assets of $34 million and long-term debt of $34 million as of December 31, 2014.

In May 2014, the FASB issued ASU No. 2014-09, which creates FASB 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. In August 2015, the FASB issued ASU No. 2015-14, which defers the effective date of ASU No. 2014-09 one year to interim and annual reporting periods beginning after December 15, 2017. 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.

(3) Property, Plant and Equipment, Net

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

	Depreciable Life	2015	2014
Property, plant and equipment:			
Generation	10 - 67 years	$ 12,164	$ 11,932
Transmission	58 - 75 years	5,914	5,392
Distribution	20 - 70 years	6,408	6,197
Intangible plant[1]	5 - 62 years	875	879
Other	5 - 60 years	1,396	1,413
Property, plant and equipment in-service		26,757	25,813
Accumulated depreciation and amortization		(8,360)	(8,026)
Net property, plant and equipment in-service		18,397	17,787
Construction work-in-progress		629	932
Total property, plant and equipment, net		$ 19,026	$ 18,719

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

The average depreciation and amortization rate applied to depreciable property, plant and equipment was 2.9%, 3.0% and 2.8% for the years ended December 31, 2015, 2014 and 2013, respectively.

Depreciation Study

PacifiCorp revised its depreciation rates effective January 1, 2014 based on results of a depreciation study approved by its state regulatory commissions. 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 $155 million and $143 million as of December 31, 2015 and 2014, respectively, and accumulated depreciation of $112 million and $107 million as of December 31, 2015 and 2014, 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, 2015 (dollars in millions):

	PacifiCorp Share	Facility in Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
Jim Bridger Nos. 1 - 4	67%	$ 1,289	$ 566	$ 83
Hunter No. 1	94	469	154	—
Hunter No. 2	60	293	94	—
Wyodak	80	457	198	3
Colstrip Nos. 3 and 4	10	239	128	2
Hermiston [(1)]	50	177	71	1
Craig Nos. 1 and 2	19	325	213	18
Hayden No. 1	25	76	30	—
Hayden No. 2	13	30	18	7
Foote Creek	79	39	24	—
Transmission and distribution facilities	Various	577	178	46
Total		$ 3,971	$ 1,674	$ 160

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

In October 2015, PacifiCorp and Idaho Power Company ("Idaho Power") each transferred to the other party full or undivided interests in specified transmission-related equipment and facilities under a Joint Purchase and Sale Agreement executed in October 2014. Contemporaneously with the Joint Purchase and Sale Agreement, PacifiCorp and Idaho Power executed a Joint Ownership and Operating Agreement applicable to the specified transmission-related equipment and facilities.

(5) Regulatory Matters

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	2015	2014
Deferred income taxes[1]	26 years	$ 437	$ 446
Employee benefit plans[2]	8 years	499	491
Utah mine disposition[3]	Various	186	194
Unamortized contract values	8 years	110	123
Deferred net power costs	1 year	86	122
Unrealized loss on derivative contracts	5 years	133	85
Other	Various	234	244
Total regulatory assets		$ 1,685	$ 1,705
Reflected as:			
Current assets		$ 102	$ 131
Noncurrent assets		1,583	1,574
Total regulatory assets		$ 1,685	$ 1,705

(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 discussed below 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 Plan withdrawal and closure costs incurred to date considered probable of recovery.

PacifiCorp had regulatory assets not earning a return on investment of $1.102 billion and $1.505 billion as of December 31, 2015 and 2014, 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	2015	2014
Cost of removal[(1)]	26 years	$ 894	$ 873
Deferred income taxes	Various	12	13
Other	Various	66	58
Total regulatory liabilities		$ 972	$ 944
Reflected as:			
Current liabilities		$ 34	$ 34
Noncurrent liabilities		938	910
Total regulatory liabilities		$ 972	$ 944

(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.

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 Plan and settle PacifiCorp's other postretirement benefit obligation for UMWA participants (collectively, the "Utah Mine Disposition").

In April 2015, PacifiCorp filed all-party settlement stipulations with the UPSC and the WPSC finding that the decision to enter into the Utah Mine Disposition transaction was prudent and in the public interest. The UPSC approved the stipulation in April 2015 and the WPSC approved the stipulation in May 2015. In May 2015, the OPUC issued its final order concluding that the Utah Mine Disposition transaction produces net benefits for customers and was in the public interest. The IPUC also issued an order in May 2015, approving the Utah Mine Disposition and ruling that the decision to enter into the transaction was prudent and in the public interest. Accordingly, in June 2015, PacifiCorp sold the specified Utah mining assets and the replacement and amended coal supply agreements became effective. Refer to Note 9 for discussion of the UMWA 1974 Pension Plan withdrawal and the settlement of the other postretirement benefit obligation for UMWA participants. The Deer Creek mine is currently idled and closure activities have begun.

In December 2014, PacifiCorp also filed an advice letter with the California Public Utilities Commission ("CPUC"). In July 2015, the CPUC Energy Division issued a letter requiring PacifiCorp to file a formal application for approval of the sale of certain Utah mining assets. Accordingly, in September 2015, PacifiCorp filed an application with the CPUC.

(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):

2015:		
Credit facilities	$	1,200
Less:		
Short-term debt		(20)
Tax-exempt bond support and letters of credit		(160)
Net credit facilities	$	1,020
2014:		
Credit facilities	$	1,200
Less:		
Short-term debt		(20)
Letters of credit and tax-exempt bond support		(398)
Net credit facilities	$	782

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, 2015 and 2014, the weighted average interest rate on commercial paper borrowings outstanding was 0.65% and 0.43%, respectively. 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, 2015, PacifiCorp was in compliance with the covenants of its credit facilities.

As of December 31, 2015 and 2014, PacifiCorp had $310 million and $451 million, respectively, of fully available letters of credit issued under committed arrangements, of which $10 million and $270 million as of December 31, 2015 and 2014 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, 2015, PacifiCorp had approximately $15 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, 2015 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 (dollars in millions):

	2015			2014	
	Principal Amount	Carrying Value	Average Interest Rate	Carrying Value	Average Interest Rate
First mortgage bonds:					
5.50% to 8.635%, due through 2019	$ 855	$ 853	5.61%	$ 859	5.63%
2.95% to 8.53%, due 2021 to 2025	2,149	2,137	4.01	1,888	4.09
6.71% due 2026	100	100	6.71	100	6.71
5.25% to 7.70%, due 2031 to 2035	800	794	6.33	793	6.33
5.75% to 6.35%, due 2036 to 2039	2,500	2,480	6.06	2,479	6.06
4.10% due 2042	300	297	4.10	297	4.10
Tax-exempt bond obligations:					
Variable rates, due 2018 to 2025(1)	107	107	0.01	223	0.03
Variable rates, due 2016 to 2024(1)(2)	198	196	0.02	219	0.02
Variable rates, due 2016 to 2025(2)	59	59	0.21	36	0.22
Variable rates, due 2017 to 2018	91	91	0.22	91	0.22
Total long-term debt	7,159	7,114		6,985	
Capital lease obligations:					
8.75% to 14.61%, due through 2035	32	32	11.25	34	11.33
Total long-term debt and capital lease obligations	$ 7,191	$ 7,146		$ 7,019	

Reflected as:

	2015	2014
Current portion of long-term debt and capital lease obligations	$ 68	$ 134
Long-term debt and capital lease obligations	7,078	6,885
Total long-term debt and capital lease obligations	$ 7,146	$ 7,019

1) Supported by $310 million and $451 million of fully available letters of credit issued under committed bank arrangements as of December 31, 2015 and 2014, 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 June 2015, PacifiCorp issued $250 million of its 3.35% First Mortgage Bonds due July 2025. The net proceeds were used to fund capital expenditures and for general corporate purposes, including retirement of short-term debt.

PacifiCorp currently has regulatory authority from the OPUC and the IPUC to issue an additional $1.325 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 to issue up to $1.325 billion additional first mortgage bonds through January 2019.

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, 2015.

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 $32 million and $34 million as of December 31, 2015 and 2014, respectively, were included in property, plant and equipment, net in the Consolidated Balance Sheets.

As of December 31, 2015, the annual principal maturities of long-term debt and total capital lease obligations for 2016 and thereafter are as follows (in millions):

	Long-term Debt	Capital Lease Obligations	Total
2016	$ 66	$ 5	$ 71
2017	52	10	62
2018	586	5	591
2019	350	5	355
2020	38	4	42
Thereafter	6,067	27	6,094
Total	7,159	56	7,215
Unamortized discount and debt issuance costs	(45)	—	(45)
Amounts representing interest	—	(24)	(24)
Total	$ 7,114	$ 32	$ 7,146

(8) Income Taxes

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

	2015	2014	2013
Current:			
Federal	$ 130	$ 2	$ 54
State	26	10	13
Total	156	12	67
Deferred:			
Federal	148	260	204
State	29	43	29
Total	177	303	233
Investment tax credits	(5)	(6)	(3)
Total income tax expense	$ 328	$ 309	$ 297

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:

	2015	2014	2013
Federal statutory income tax rate	35%	35%	35%
State income taxes, net of federal income tax benefit	3	3	3
Federal income tax credits	(6)	(7)	(7)
Other	—	—	(1)
Effective income tax rate	32%	31%	30%

Income tax credits relate primarily to production tax credits earned by PacifiCorp's wind-powered generating facilities. Federal renewable electricity production tax credits are earned as energy from qualifying wind-powered generating facilities is produced and sold and are based on a per-kilowatt hour rate pursuant to the applicable federal income tax law. Wind-powered generating facilities are eligible for the credits for 10 years from the date the qualifying generating facilities are placed in-service.

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

	2015	2014
Deferred income tax assets:		
Regulatory liabilities	$ 374	$ 362
Employee benefits	189	184
Derivative contracts and unamortized contract values	94	79
State carryforwards	68	68
Loss contingencies	67	70
Asset retirement obligations	81	47
Other	88	92
	961	902
Deferred income tax liabilities:		
Property, plant and equipment	(5,030)	(4,780)
Regulatory assets	(639)	(647)
Other	(42)	(56)
	(5,711)	(5,483)
Net deferred income tax liability	$ (4,750)	$ (4,581)

The following table provides PacifiCorp's net operating loss and tax credit carryforwards and expiration dates as of December 31, 2015 (in millions):

	State
Net operating loss carryforwards	$ 1,416
Deferred income taxes on net operating loss carryforwards	$ 52
Expiration dates	2016 - 2032
Tax credit carryforwards	$ 16
Expiration dates	2016 - indefinite

The United States Internal Revenue Service has closed 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.

As of December 31, 2015 and 2014, PacifiCorp had unrecognized tax benefits totaling $13 million and $14 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 previously contributed 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, PacifiCorp's subsidiary, 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 a fund managed by the UMWA. Transfer of the assets and settlement of this obligation occurred in May 2015 and resulted in a remeasurement of the other postretirement plan assets and benefit obligation. As a result of the remeasurement, PacifiCorp recognized a $9 million settlement loss, with the portion that is probable of recovery deferred as a regulatory asset. No curtailment accounting was 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 closure of the Deer Creek mining operations, withdrawal from the UMWA 1974 Pension Plan was involuntarily triggered in June 2015 when UMWA employees ceased performing work for the subsidiary. 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		
	2015	2014	2013	2015	2014	2013
Service cost	$ 4	$ 5	$ 6	$ 3	$ 6	$ 9
Interest cost	53	57	54	16	28	25
Expected return on plan assets	(77)	(76)	(74)	(23)	(31)	(30)
Net amortization	42	29	48	(4)	2	8
Net periodic benefit cost (credit)	$ 22	$ 15	$ 34	$ (8)	$ 5	$ 12

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	
	2015	2014	2015	2014
Plan assets at fair value, beginning of year	$ 1,146	$ 1,171	$ 482	$ 486
Employer contributions	4	10	1	1
Participant contributions	—	—	6	7
Actual return on plan assets	—	53	1	25
Settlement	—	—	(150)	—
Benefits paid	(107)	(88)	(35)	(37)
Plan assets at fair value, end of year	$ 1,043	$ 1,146	$ 305	$ 482

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

	Pension		Other Postretirement	
	2015	2014	2015	2014
Benefit obligation, beginning of year	$ 1,378	$ 1,230	$ 539	$ 598
Service cost	4	5	3	6
Interest cost	53	57	16	28
Participant contributions	—	—	6	7
Actuarial (gain) loss	(39)	174	(17)	(63)
Settlement	—	—	(150)	—
Benefits paid	(107)	(88)	(35)	(37)
Benefit obligation, end of year	$ 1,289	$ 1,378	$ 362	$ 539
Accumulated benefit obligation, end of year	$ 1,289	$ 1,378		

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 associated with the UMWA plan participants to $150 million. Refer to "Utah Mine Disposition and Labor Agreement" above.

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	
	2015	2014	2015	2014
Plan assets at fair value, end of year	$ 1,043	$ 1,146	$ 305	$ 482
Less - Benefit obligation, end of year	1,289	1,378	362	539
Funded status	$ (246)	$ (232)	$ (57)	$ (57)
Amounts recognized on the Consolidated Balance Sheets:				
Other current liabilities	$ (4)	$ (4)	$ —	$ —
Other long-term liabilities	(242)	(228)	(57)	(57)
Amounts recognized	$ (246)	$ (232)	$ (57)	$ (57)

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 $52 million and $51 million as of December 31, 2015 and 2014, 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	
	2015	2014	2015	2014
Net loss	$ 508	$ 520	$ 36	$ 41
Prior service credit	(13)	(21)	(19)	(26)
Regulatory deferrals	(3)	(3)	9	2
Total	$ 492	$ 496	$ 26	$ 17

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2015 and 2014 is as follows (in millions):

	Regulatory Asset	Accumulated Other Comprehensive Loss	Total
Pension			
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
Net loss (gain) arising during the year	40	(2)	38
Net amortization	(41)	(1)	(42)
Total	(1)	(3)	(4)
Balance, December 31, 2015	$ 473	$ 19	$ 492

	Regulatory Asset
Other Postretirement	
Balance, December 31, 2013	$ 77
Net gain arising during the year	(58)
Net amortization	(2)
Total	(60)
Balance, December 31, 2014	17
Net loss arising during the year	5
Net amortization	4
Total	9
Balance, December 31, 2015	$ 26

The net loss, prior service credit and regulatory deferrals that will be amortized in 2016 into net periodic benefit cost are estimated to be as follows (in millions):

	Net Loss	Prior Service Credit	Regulatory Deferrals	Total
Pension	$ 42	$ (8)	$ (1)	$ 33
Other postretirement	1	(7)	1	(5)
Total	$ 43	$ (15)	$ —	$ 28

Plan Assumptions

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

	Pension			Other Postretirement		
	2015	2014	2013	2015	2014	2013
Benefit obligations as of December 31:						
Discount rate	4.40%	4.00%	4.80%	4.35%	3.90%	4.90%
Rate of compensation increase	2.75	2.75	3.00	N/A	N/A	N/A
Net periodic benefit cost for the years ended December 31:						
Discount rate	4.00%	4.80%	4.05%	3.99%	4.90%	4.10%
Expected return on plan assets	7.50	7.50	7.50	7.08	7.50	7.50
Rate of compensation increase	2.75	3.00	3.00	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 historical performance and forward-looking views of the financial markets. As discussed above in "Utah Mine Disposition and Labor Agreement," PacifiCorp remeasured the other postretirement plan assets and benefit obligation as of May 31, 2015. The other postretirement assumptions for the year ended December 31, 2015 presented above reflect a weighted average calculation that considered the assumptions used in the periods preceding and subsequent to the remeasurement.

As a result of the labor settlement discussed above in "Utah Mine Disposition and Labor Agreement," the benefit obligation for the other postretirement plan is no longer affected by healthcare cost trends. The assumed healthcare cost trend rates used to determine the benefit obligation as of December 31, 2014 were as follows:

Healthcare cost trend rate assumed for next year	8.00%
Rate that the cost trend rate gradually declines to	5.00%
Year that the rate reaches the rate it is assumed to remain at	2025

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be $4 million and $- million, respectively, during 2016. 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 2016 through 2020 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments	
	Pension	Other Postretirement
2016	$ 108	$ 28
2017	110	28
2018	108	28
2019	109	27
2020	107	30
2021-2025	448	122

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, 2015:

	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, 2015				
Cash equivalents	$ —	$ 10	$ —	$ 10
Debt securities:				
United States government obligations	19	—	—	19
Corporate obligations	—	42	—	42
Municipal obligations	—	5	—	5
Agency, asset and mortgage-backed obligations	—	43	—	43
Equity securities:				
United States companies	408	—	—	408
International companies	17	—	—	17
Investment funds(2)	83	351	—	434
Limited partnership interests(3)	—	—	65	65
Total	$ 527	$ 451	$ 65	$ 1,043
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

(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 53% and 47%, respectively, for 2015 and 50% and 50%, respectively, for 2014, and are invested in United States and international securities of approximately 40% and 60%, respectively, for 2015 and 43% and 57%, respectively, for 2014.

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

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

	Input Levels for Fair Value Measurements			
	Level 1[(1)]	Level 2[(1)]	Level 3[(1)]	Total
As of December 31, 2015				
Cash and cash equivalents	$ 4	$ 1	$ —	$ 5
Debt securities:				
United States government obligations	9	—	—	9
Corporate obligations	—	15	—	15
Municipal obligations	—	1	—	1
Agency, asset and mortgage-backed obligations	—	14	—	14
Equity securities:				
United States companies	95	—	—	95
International companies	4	—	—	4
Investment funds[(2)]	32	126	—	158
Limited partnership interests[(3)]	—	—	4	4
Total	$ 144	$ 157	$ 4	$ 305
As of December 31, 2014				
Cash and cash equivalents[(4)]	$ 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[(2)]	84	94	—	178
Limited partnership interests[(3)]	—	—	5	5
Total	$ 347	$ 130	$ 5	$ 482

(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 61% and 39%, respectively, for 2015 and 63% and 37%, respectively, for 2014, and are invested in United States and international securities of approximately 67% and 33%, respectively, for 2015 and 64% and 36%, respectively, for 2014.

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

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

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, 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
Actual return on plan assets still held at December 31, 2015	5	—
Purchases, sales, distributions and settlements	(10)	(1)
Balance, December 31, 2015	$ 65	$ 4

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, previously contributed to the UMWA 1974 Pension Plan (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's subsidiary, Energy West Mining Company, triggered involuntary withdrawal from the UMWA 1974 Pension Plan in June 2015 when the UMWA employees ceased performing work for the subsidiary. PacifiCorp recorded its best estimate of the withdrawal obligation in December 2014 when withdrawal was considered probable and deferred the portion of the obligation considered probable of recovery to a regulatory asset. The estimate of the withdrawal obligation provided by the UMWA 1974 Pension Plan is $97 million for a withdrawal occurring by July 1, 2015. Energy West Mining Company may elect to make a lump sum payment or annual installment payments to settle the withdrawal obligation.

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 occurred as a result of Energy West Mining Company's withdrawal from the UMWA 1974 Pension Plan. 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 withdrew during the three years prior to a mass withdrawal.

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, 2015	2014	2013	Funding improvement plan	Surcharge imposed under PPA(1)	Contributions(1) 2015	2014	2013	Year contributions to plan exceeded more than 5% of total contributions(2)
UMWA 1974 Pension Plan	52-1050282	Critical and Declining	Critical	Seriously Endangered	Implemented	Yes	$ 1	$ 2	$ 3	None
Local 57 Trust Fund	87-0640888	At least 80%	At least 80%	At least 80%	None	None	$ 8	$ 9	$ 9	2014, 2013, 2012

(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 Plan, 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 Plan, information is for plan years beginning July 1, 2013 and 2012. Information for the plan years beginning July 1, 2015 and 2014 is not yet available. For the Local 57 Trust Fund, information is for plan years beginning July 1, 2014, 2013 and 2012. Information for the plan year beginning July 1, 2015 is not yet available.

The current collective bargaining agreements governing the Local 57 Trust Fund expire in January 2020.

Defined Contribution Plan

PacifiCorp's 401(k) plan covers substantially all employees. PacifiCorp's matching contributions are based on each participant's level of contribution, and certain participants receive contributions based on eligible pre-tax annual compensation. Contributions cannot exceed the maximum allowable for tax purposes. PacifiCorp's contributions to the 401(k) plan were $35 million, $34 million and $35 million for the years ended December 31, 2015, 2014 and 2013, 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 $894 million and $873 million as of December 31, 2015 and 2014, respectively.

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

	2015	2014
Beginning balance	$ 135	$ 138
Change in estimated costs	62	(3)
Additions	30	—
Retirements	(10)	(6)
Accretion	7	6
Ending balance	$ 224	$ 135
Reflected as:		
Other current liabilities	$ 35	$ 21
Other long-term liabilities	189	114
	$ 224	$ 135

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 United States 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 was published in the Federal Register in April 2015 and was effective in October 2015. The final rule substantially impacted existing AROs reflected in the December 31, 2015 change in estimated costs above and also resulted in the recognition of additional AROs.

(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, 2015					
Not designated as hedging contracts[1]:					
Commodity assets	$ 10	$ —	$ 2	$ —	$ 12
Commodity liabilities	(1)	—	(58)	(89)	(148)
Total	9	—	(56)	(89)	(136)
Total derivatives	9	—	(56)	(89)	(136)
Cash collateral receivable	—	—	18	57	75
Total derivatives - net basis	$ 9	$ —	$ (38)	$ (32)	$ (61)
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)

(1) PacifiCorp's commodity derivatives are generally included in rates and as of December 31, 2015 and 2014, a regulatory asset of $133 million and $85 million, respectively, was recorded related to the net derivative liability of $136 million and $85 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):

	2015	2014
Beginning balance	$ 85	$ 55
Changes in fair value recognized in regulatory assets	82	45
Net gains (losses) reclassified to operating revenue	40	(4)
Net losses reclassified to energy costs	(74)	(11)
Ending balance	$ 133	$ 85

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	2015	2014
Electricity purchases (sales)	Megawatt hours	1	(1)
Natural gas purchases	Decatherms	111	113
Fuel oil purchases	Gallons	11	3

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, 2015, 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 $142 million and $113 million as of December 31, 2015 and 2014, respectively, for which PacifiCorp had posted collateral of $75 million and $28 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, 2015 and 2014, PacifiCorp would have been required to post $64 million and $75 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, 2015					
Assets:					
Commodity derivatives	$ —	$ 9	$ 3	$ (3)	$ 9
Money market mutual funds[(2)]	13	—	—	—	13
Investment funds	15	—	—	—	15
	$ 28	$ 9	$ 3	$ (3)	$ 37
Liabilities - Commodity derivatives	$ —	$ (148)	$ —	$ 78	$ (70)
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)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $75 million and $28 million as of December 31, 2015 and 2014, respectively.

(2) Amounts are included in cash and cash equivalents, other current assets and other assets on the Consolidated Balance Sheets. Money market mutual funds are accounted for as available-for-sale securities and the fair value 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 and investment funds are stated at fair value. PacifiCorp uses a readily observable quoted market price or net asset value of an identical security in an active market to record the fair value.

PacifiCorp's long-term debt is carried at cost on the Consolidated Balance Sheets. 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):

	2015		2014	
	Carrying Value	**Fair Value**	**Carrying Value**	**Fair Value**
Long-term debt	$ 7,114	$ 8,210	$ 6,985	$ 8,358

(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. After considering various motions filed by the parties to expand or limit damages, interest and attorney's fees, in May 2013, the court entered a final judgment 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 were heard in September 2015. As of December 31, 2015, PacifiCorp had accrued $122 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.

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 begin 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 is required to provide, among other things, protection for PacifiCorp from all liabilities associated with dam removal activities. As of December 31, 2015, no federal legislation was enacted. In February 2016, the principal parties to the KHSA (PacifiCorp, the states of California and Oregon and the United States Departments of the Interior and Commerce) executed an agreement in principle committing to explore potential amendment of the KHSA to facilitate removal of the Klamath dams through a FERC process without the need for federal legislation. Any amendment to the KHSA would ensure that the existing KHSA framework would remain in place, capping PacifiCorp's costs and requiring transfer of the dams to a separate entity that would remove the dams and provide PacifiCorp and its customers with protections against potential dam removal liabilities. If the KHSA is not amended, then PacifiCorp will resume relicensing with the FERC.

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, 2015, PacifiCorp's assets included $81 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, depending upon the state jurisdiction.

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 $252 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, 2015 are as follows (in millions):

	2016	2017	2018	2019	2020	2021 and Thereafter	Total
Contract type:							
Purchased electricity contracts - commercially operable	$ 168	$ 71	$ 70	$ 67	$ 68	$ 401	$ 845
Purchased electricity contracts - non-commercially operable	16	102	104	104	104	1,687	2,117
Fuel contracts	862	689	558	542	496	1,720	4,867
Construction commitments	144	12	10	2	2	5	175
Transmission	105	97	91	76	55	508	932
Operating leases and easements	5	4	4	4	4	42	63
Maintenance, service and other contracts	36	30	19	24	11	74	194
Total commitments	$ 1,336	$ 1,005	$ 856	$ 819	$ 740	$ 4,437	$ 9,193

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 $13 million for 2015, $15 million for 2014 and $24 million for 2013.

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 2015, 2014 and 2013 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 $15 million for the year ended December 31, 2015 and $16 million for each of the years ended December 31, 2014 and 2013.

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, 2015 and 2014. 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, 2015 and 2014.

(15) Common Shareholder's Equity

In February 2016, PacifiCorp declared a dividend of $100 million payable to PPW Holdings LLC, a wholly owned subsidiary of BHE and PacifiCorp's direct parent company ("PPW Holdings") in March 2016.

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, 2015, 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, 2015, PacifiCorp's actual common equity percentage, as calculated under this measure, was 52%, and PacifiCorp would have been permitted to dividend $2.0 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, 2015, 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 $11 million and $13 million as of December 31, 2015 and 2014, 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 power purchase agreement that expires on July 1, 2016. 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 $39 million during the year ended December 31, 2015 and $38 million during each of the years ended December 31, 2014 and 2013. 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 $190 million and $192 million as of December 31, 2015 and 2014, 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 during each of the years ended December 31, 2015 and 2014 and $17 million during the year ended December 31, 2013. Payables associated with these administrative services were $2 million and $1 million as of December 31, 2015 and 2014, respectively. Amounts charged by PacifiCorp to BHE and its subsidiaries under this agreement totaled $7 million, $10 million and $9 million during the years ended December 31, 2015, 2014 and 2013, respectively. Receivables associated with these administrative services were $1 million and $7 million as of December 31, 2015 and 2014, 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 wholesale electricity purchases and transmission of electricity, transportation of natural gas and employee relocation services. These expenses totaled $8 million, $7 million and $5 million during the years ended December 31, 2015, 2014 and 2013, respectively. Payables associated with these services were $1 million as of December 31, 2015 and 2014. Amounts charged by PacifiCorp to subsidiaries of BHE for wholesale electricity sales in the ordinary course of business totaled $2 million, $5 million and $- million during the years ended December 31, 2015, 2014 and 2013, respectively.

PacifiCorp has long-term transportation contracts with BNSF Railway Company ("BNSF"), an indirect wholly owned subsidiary of Berkshire Hathaway, PacifiCorp's ultimate parent company. Transportation costs under these contracts were $39 million during each of the years ended December 31, 2015 and 2014 and $32 million during the year ended December 31, 2013. As of December 31, 2015 and 2014, PacifiCorp had $1 million and $3 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 $- million and $2 million as of December 31, 2015 and 2014, respectively. Proceeds from claims were $2 million, $- million and $1 million during the years ended December 31, 2015, 2014 and 2013, respectively.

PacifiCorp is party to a tax-sharing agreement and is part of the Berkshire Hathaway United States federal income tax return. Federal and state income taxes receivable from BHE were $17 million and $133 million as of December 31, 2015 and 2014, respectively. For the years ended December 31, 2015, 2014 and 2013, cash paid for federal and state income taxes to BHE totaled $40 million, $161 million and $120 million, respectively.

PacifiCorp transacts with its equity investees, Bridger Coal and Trapper Mining Inc. During the years ended December 31, 2015, 2014 and 2013, PacifiCorp charged Bridger Coal $19 million, $3 million and $2 million, respectively, primarily for the sale of mining equipment in 2015, 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, 2015 and 2014. Services provided by equity investees to PacifiCorp primarily relate to coal purchases. During the years ended December 31, 2015, 2014 and 2013, coal purchases from PacifiCorp's equity investees totaled $181 million, $146 million and $152 million, respectively. Payables to PacifiCorp's equity investees were $16 million and $19 million as of December 31, 2015 and 2014, 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):

	2015	2014	2013
Interest paid, net of amounts capitalized	$ 342	$ 340	$ 340
Income taxes paid, net	$ 40	$ 161	$ 120
Supplemental disclosure of non-cash investing and financing activities:			
Accounts payable related to property, plant and equipment additions	$ 147	$ 140	$ 157
Accounts receivable related to property, plant and equipment sales	$ 40	$ —	$ —

Item 6. Selected Financial Data

Information required by Item 6 is omitted pursuant to General Instruction I(2)(a) to Form 10-K.

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

General

MidAmerican Funding is an Iowa limited liability company whose sole member is BHE. MidAmerican Funding owns all of the outstanding common stock of MHC, which owns all of the common stock of MidAmerican Energy, Midwest Capital and MEC Construction. MHC, MidAmerican Funding and BHE are headquartered in Des Moines, Iowa.

The following is management's discussion and analysis of certain significant factors that have affected the consolidated financial condition and results of operations of MidAmerican Funding and its subsidiaries and MidAmerican Energy as presented in this joint filing. Information in Management's Discussion and Analysis related to MidAmerican Energy, whether or not segregated, also relates to MidAmerican Funding. Information related to other subsidiaries of MidAmerican Funding pertains only to the discussion of the financial condition and results of operations of MidAmerican Funding. Where necessary, discussions have been segregated under the heading "MidAmerican Funding" to allow the reader to identify information applicable only to MidAmerican Funding. Explanations include management's best estimate of the impact of weather, customer growth and other factors. This discussion should be read in conjunction with the historical Consolidated Financial Statements and Notes to Consolidated Financial Statements in Item 8 of this Form 10-K. MidAmerican Energy's and MidAmerican Funding's actual results in the future could differ significantly from the historical results.

Results of Operations

Overview

MidAmerican Energy -

MidAmerican Energy's earnings on common stock for 2015 was $462 million, an increase of $45 million, or 11%, compared to 2014 due to higher regulated electric margins of $119 million, higher production tax credits of $27 million and lower fossil-fueled generation maintenance of $10 million, partially offset by higher depreciation and amortization of $56 million due to wind-powered generation and other plant placed in-service, lower AFUDC of $27 million, lower regulated natural gas margins of $12 million due to warmer temperatures in 2015 and higher interest expense of $9 million due to the issuance of first mortgage bonds in April 2014 and October 2015, net of the effect of a related redemption of senior notes in May 2014. Regulated electric margins increased primarily due to higher retail rates in Iowa and changes in rate structure related to seasonal pricing, lower purchased power costs, a lower average cost of fuel for generation and higher transmission revenue, partially offset by lower wholesale revenue.

MidAmerican Energy's earnings on common stock for 2014 was $417 million, an increase of $68 million, or 19%, compared to 2013 due to an increase in regulated electric retail gross margin from higher Iowa electric retail rates and higher industrial electricity sales, higher regulated gas gross margin from colder winter temperatures in 2014, a decrease in depreciation and amortization expense due to changes in depreciation rates in 2014 and 2013 and higher AFUDC, partially offset by higher operations and maintenance expenses and higher interest expense from the issuance of first mortgage bonds in September 2013 and April 2014, net of the effect of related debt retirements in December 2013 and May 2014.

MidAmerican Funding -

Net income attributable to MidAmerican Funding for 2015 was $458 million, an increase of $49 million, or 12%, compared to $409 million for 2014. Net income attributable to MidAmerican Funding for 2014 was $409 million, an increase of $69 million, or 20%, compared to $340 million for 2013. In addition to the changes in MidAmerican Energy's earnings discussed above, MidAmerican Funding recognized an $8 million after-tax gain on the sale of an investment in a generating facility lease in 2015.

Regulated Electric Gross Margin

A comparison of key results related to regulated electric gross margin is as follows for the years ended December 31:

	2015	2014	Change		2014	2013	Change	
Gross margin (in millions):								
Operating revenue	$ 1,837	$ 1,817	$ 20	1 %	$ 1,817	$ 1,762	$ 55	3 %
Cost of fuel, energy and capacity[(1)]	433	532	(99)	(19)	532	517	15	3
Gross margin	$ 1,404	$ 1,285	$ 119	9	$ 1,285	$ 1,245	$ 40	3
Sales (GWh):								
Residential	6,166	6,429	(263)	(4)%	6,429	6,572	(143)	(2)%
Commercial	3,806	4,084	(278)	(7)	4,084	4,265	(181)	(4)
Industrial	11,487	10,642	845	8	10,642	10,001	641	6
Other	1,583	1,622	(39)	(2)	1,622	1,614	8	—
Total retail	23,042	22,777	265	1	22,777	22,452	325	1
Wholesale	8,741	9,716	(975)	(10)	9,716	10,226	(510)	(5)
Total sales	31,783	32,493	(710)	(2)	32,493	32,678	(185)	(1)
Average number of retail customers (in thousands)	752	746	6	1 %	746	739	7	1 %
Average revenue per MWh:								
Retail	$ 69.68	$ 66.92	$ 2.76	4 %	$ 66.92	$ 65.76	$ 1.16	2 %
Wholesale	$ 20.09	$ 26.48	$ (6.39)	(24)%	$ 26.48	$ 25.08	$ 1.40	6 %
Heating degree days	5,654	6,899	(1,245)	(18)%	6,899	6,733	166	2 %
Cooling degree days	1,067	933	134	14 %	933	1,143	(210)	(18)%
Sources of energy (GWh)[(2)]:								
Coal	15,525	18,234	(2,709)	(15)%	18,234	18,222	12	— %
Nuclear	3,885	3,842	43	1	3,842	3,889	(47)	(1)
Natural gas	199	114	85	75	114	267	(153)	(57)
Wind and other[(3)]	9,606	7,965	1,641	21	7,965	7,458	507	7
Total energy generated	29,215	30,155	(940)	(3)	30,155	29,836	319	1
Energy purchased	3,194	3,029	165	5	3,029	3,528	(499)	(14)
Total	32,409	33,184	(775)	(2)	33,184	33,364	(180)	(1)

(1) Effective in August 2014, MidAmerican Energy is allowed to recover fluctuations in electric energy costs for its Iowa retail electric generation through an energy adjustment mechanism.

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

(3) 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 renewable portfolio standards or other regulatory requirements or (b) sold to third parties in the form of renewable energy credits or other environmental commodities.

For 2015 compared to 2014, regulated electric gross margin increased $119 million as follows:

(1) Higher retail gross margin of $109 million due to -

- an increase of $70 million from higher electric rates, reflecting higher rates of $45 million annually, effective January 2015, for the second step of the 2014 Iowa rate increase, $16 million annually in Illinois, effective December 2014, and an increase from the full-year impact of changes in Iowa rate structure related to seasonal pricing, which were effective with the implementation of final Iowa base rates in August 2014 that resulted in a greater differential between summer rates from June to September and rates in the remaining months;
- an increase of $32 million from lower retail energy costs primarily due to a lower average cost of fuel for generation and lower purchased power costs;
- an increase of $11 million from non-weather-related usage factors;
- an increase of $8 million principally from higher recoveries through bill riders and adjustment clauses; and
- a decrease of $8 million from the impact of temperatures;

(2) Higher MVP transmission revenue of $25 million, which is expected to increase as projects are constructed over the next two years; partially offset by

(3) Lower wholesale gross margin of $15 million due to decreases of -

- $9 million from lower sales volumes; and
- $6 million from lower average prices.

For 2014 compared to 2013, regulated electric gross margin increased $40 million as follows:

(1) Higher retail gross margin of $34 million due to -

- an increase of $49 million from higher electric rates, reflecting the increase in Iowa base rates implemented in August 2013 and, effective with the implementation of final base rates in August 2014, changes in rate structure related to seasonal pricing, as discussed above, and new adjustment clauses for recovery of retail energy production and transmission costs;
- an increase of $22 million from higher recoveries of DSM program costs;
- a decrease of $16 million from higher retail energy costs, primarily due to higher coal-fueled generation costs per unit and higher purchased power costs;
- a decrease of $14 million from lower sales volumes for higher-priced, weather-sensitive customers as a result of milder summer temperatures in 2014, net of greater industrial sales volumes; and
- a decrease of $7 million from lower steam sales, partially due to the expiration of a contract, and lower sales of renewable energy credits;

(2) Higher MVP transmission revenue of $6 million.

(3) An unchanged wholesale gross margin compared to 2013 as a higher average margin per megawatt hour sold was offset by lower sales volumes primarily due to the higher retail energy requirements.

Regulated Gas Gross Margin

A comparison of key results related to regulated gas gross margin is as follows for the years ended December 31:

	2015	2014	Change		2014	2013	Change	
Gross margin (in millions):								
Operating revenue	$ 661	$ 996	$ (335)	(34)%	$ 996	$ 824	$ 172	21%
Cost of gas sold	397	720	(323)	(45)	720	558	162	29
Gross margin	$ 264	$ 276	$ (12)	(4)	$ 276	$ 266	$ 10	4
Natural gas throughput (000's Dths):								
Residential	46,519	56,224	(9,705)	(17)%	56,224	53,725	2,499	5%
Commercial	23,466	28,256	(4,790)	(17)	28,256	27,308	948	3
Industrial	4,833	5,335	(502)	(9)	5,335	5,017	318	6
Other	37	48	(11)	(23)	48	45	3	7
Total retail sales	74,855	89,863	(15,008)	(17)	89,863	86,095	3,768	4
Wholesale sales	35,250	25,346	9,904	39	25,346	29,762	(4,416)	(15)
Total sales	110,105	115,209	(5,104)	(4)	115,209	115,857	(648)	(1)
Gas transportation service	80,001	82,314	(2,313)	(3)	82,314	78,208	4,106	5
Total gas throughput	190,106	197,523	(7,417)	(4)	197,523	194,065	3,458	2
Average number of retail customers (in thousands)	733	726	7	1 %	726	719	7	1%
Average revenue per retail Dth sold	$ 7.12	$ 9.24	$ (2.12)	(23)%	$ 9.24	$ 7.87	$ 1.37	17%
Average cost of natural gas per retail Dth sold	$ 4.03	$ 6.54	$ (2.51)	(38)%	$ 6.54	$ 5.16	$ 1.38	27%
Combined retail and wholesale average cost of natural gas per Dth sold	$ 3.61	$ 6.25	$ (2.64)	(42)%	$ 6.25	$ 4.81	$ 1.44	30%
Heating degree days	5,913	7,209	(1,296)	(18)%	7,209	7,036	173	2%

Regulated gas revenue includes PGAs through which MidAmerican Energy is allowed to recover the cost of gas sold from its retail gas utility customers. Consequently, fluctuations in the cost of gas sold do not directly affect gross margin or net income because regulated gas revenue reflects comparable fluctuations through the PGAs. For 2015, MidAmerican Energy's combined retail and wholesale average per-unit cost of gas sold decreased 42%, resulting in a decrease of $290 million in gas revenue and cost of gas sold compared to 2014. For 2014 compared to 2013, MidAmerican Energy's combined retail and wholesale average per-unit cost of gas sold increased 30%, resulting in an increase of $165 million in gas revenue and cost of gas sold. Additionally, fluctuations in gas wholesale sales impact gas revenue and cost of gas sold but do not affect regulated gas gross margin.

For 2015 compared to 2014, regulated gas gross margin decreased $12 million primarily due to:

- $20 million from lower retail sales volumes reflecting warmer winter temperatures in 2015; partially offset by
- $7 million from an increase due to non-weather-related usage factors.

For 2014 compared to 2013, regulated gas gross margin increased $10 million primarily due to:

- $5 million from higher retail sales volumes due to colder winter temperatures in 2014 and other usage factors; and
- $4 million higher revenue from recoveries of DSM program costs.

Regulated Operating Costs and Expenses

Operations and Maintenance

Operations and maintenance expenses of $687 million for 2015 decreased $12 million compared to 2014 substantially due to $10 million of lower fossil-fueled generation maintenance costs as a result of planned outages in 2014, $9 million of lower electric distribution costs due to less inclement weather and emergency storm restoration, $8 million for lower expense resulting from a one-time refund in June 2014 to MidAmerican Energy's customers for insurance recoveries related to environmental matters, $4 million of lower pension and postretirement costs and $3 million of lower healthcare benefit costs, partially offset by $10 million of higher wind-powered generation costs due to the addition of facilities and increases in transmission operations costs from MISO and DSM program costs of $7 million and $5 million, respectively, both of which are matched by increases in revenues.

Operations and maintenance expenses of $699 million for 2014 increased $40 million compared to 2013 substantially due to $25 million of higher DSM program costs, which are matched by increases in electric and gas revenue, $9 million of higher generation costs due largely to wind-powered generating facility maintenance costs, $8 million of expense resulting from a one-time refund in June 2014 to MidAmerican Energy's customers for insurance recoveries related to environmental matters and $6 million of higher transmission costs from MISO, partially offset by $9 million of lower pension and postretirement costs.

Depreciation and Amortization

Depreciation and amortization expense of $407 million for 2015 increased $56 million compared to 2014 primarily due to additional wind-powered generating facilities placed in service in the second half of 2014 and the second half of 2015. Depreciation and amortization expense of $351 million for 2014 decreased $52 million compared to 2013 due to a $79 million reduction in utility plant depreciation for changes in depreciation rates in 2013 and 2014, as discussed below, partially offset by $28 million from utility plant additions.

During the third quarter of 2013, MidAmerican Energy revised its depreciation rates for certain electric generating facilities based on the results of a new depreciation study. The new rates reflect longer estimated useful lives for wind-powered generating facilities placed in service in 2011 and 2012 and a lower accrual rate for the cost of removal regulatory liability related to coal-fueled generating facilities. The effect of this change was to reduce depreciation and amortization expense by $20 million for 2013 and $49 million annually based on depreciable plant balances at the time of the change. Effective January 1, 2014, MidAmerican Energy revised depreciation rates for certain electric generating facilities based on the results of its 2013 Iowa electric retail rate case. The new depreciation rates reflect longer estimated useful lives for certain generating facilities. The effect of this change was to reduce depreciation and amortization expense by $50 million annually based on depreciable plant balances at the time of the change.

Nonregulated Gross Margin

MidAmerican Energy -

	2015	2014	Change		2014	2013	Change	
Gross margin (in millions):								
Nonregulated operating revenue	$ 909	$ 927	$ (18)	(2)%	$ 927	$ 817	$ 110	13 %
Nonregulated cost of sales	855	863	(8)	(1)	863	764	99	13
Nonregulated gross margin	$ 54	$ 64	$ (10)	(16)	$ 64	$ 53	$ 11	21
Nonregulated electric retail sales (GWh)	10,770	9,730	1,040	11 %	9,730	9,497	233	2 %
Nonregulated gas sales (000's Dths)	30,321	31,605	(1,284)	(4)%	31,605	36,887	(5,282)	(14)%

MidAmerican Energy's nonregulated gross margin decreased $10 million for 2015 compared to 2014 and increased $11 million for 2014 compared to 2013. The following table presents the margins related to various nonregulated activities (in millions):

	2015	2014	2013
Nonregulated electric	$ 46	$ 46	$ 49
Nonregulated gas	5	9	2
Income sharing arrangements under regulated gas tariffs	3	9	2
Total nonregulated gross margin	$ 54	$ 64	$ 53

For 2015 compared to 2014, nonregulated operating revenue and cost of sales decreased primarily due to lower gas prices, per-unit cost and sales volumes, partially offset by higher electric sales volumes, prices and per-unit costs. Nonregulated gross margin decreased due to the lower income from the portion of margins on regulated gas wholesale sales that is retained by MidAmerican Energy and lower average margins per unit sold on nonregulated gas and electric sales, partially offset by higher nonregulated electric sales volumes.

For 2014 compared to 2013, nonregulated operating revenue and cost of sales increased primarily due to higher gas and electric sales. The impact of lower nonregulated gas sales volumes was largely offset by higher nonregulated electric sales volumes. Nonregulated gross margin increased due to higher revenue from the portion of margins on regulated gas wholesale sales that is retained by MidAmerican Energy and higher nonregulated gas margins, primarily from the increase in price, partially offset by lower nonregulated electric margins due to the increase in per-unit cost.

Effective January 1, 2016, the nonregulated electric and gas operations were transferred to a subsidiary of BHE. Refer to Note 21 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K for additional information regarding the transfer.

Other Income and (Expense)

MidAmerican Energy -

Interest Expense

Interest expense of $183 million for 2015 increased $9 million compared to 2014 due to higher interest expense from the issuance of first mortgage bonds totaling $850 million in April 2014 and $650 million in October 2015, net of lower interest expense from the redemption of $350 million of 4.65% senior notes in May 2014. Refer to Note 8 of Notes to Financial Statements in Item 8 of this Form 10-K for further discussion of first mortgage bonds.

Interest expense of $174 million for 2014 increased $23 million compared to 2013 due to higher interest expense from the issuance of first mortgage bonds totaling $950 million in September 2013 and $850 million in April 2014, partially offset by a decrease in interest expense from the payment in December 2013 of amounts owed for the construction of wind-powered generating facilities that were deferred in 2011 and the redemption of $350 million of 4.65% senior notes in May 2014. Refer to Note 8 of Notes to Financial Statements in Item 8 of this Form 10-K for further discussion of first mortgage bonds and deferred construction payments.

Allowance for Borrowed Funds and Allowance for Equity Funds

For 2015 compared to 2014, allowance for borrowed funds of $8 million and allowance for equity funds of $20 million decreased $8 million and $19 million, respectively, primarily due to lower construction work-in-progress balances related to the installation of emissions control equipment at a number of MidAmerican Energy's jointly owned generating facilities and wind-powered generation.

For 2014 compared to 2013, allowance for borrowed funds of $16 million and allowance for equity funds of $39 million increased $9 million and $20 million, respectively, primarily due to higher construction work-in-progress balances related to the construction of wind-powered generating facilities.

Other, Net

MidAmerican Energy's other, net totaled $5 million for 2015, $10 million for 2014 and $16 million for 2013. The variance for 2015 and 2014 compared to the respective preceding year was primarily due to fluctuations in returns from corporate-owned life insurance policies.

MidAmerican Funding -

Other, Net

In addition to the fluctuations discussed above for MidAmerican Energy, MidAmerican Funding's other, net for 2015 reflects a $13 million pre-tax gain on the sale of an investment in a generating facility lease in 2015.

Income Tax Benefit

MidAmerican Energy -

MidAmerican Energy's income tax benefit was $141 million for 2015, an increase of $37 million compared to $104 million for 2014, with an effective tax rate of (44)% for 2015 and (33)% for 2014. The change in the effective tax rate was due to an increase of $27 million in production tax credits and the effects of ratemaking.

MidAmerican Energy's income tax benefit was $104 million for 2014, an increase of $1 million compared to $103 million for 2013, with an effective tax rate of (33)% for 2014 and (42)% for 2013. The change in the effective tax rate was due to higher pre-tax income, partially offset by the effects of ratemaking and an increase of $11 million in production tax credits.

State utility rate regulation in Iowa requires that the tax effect of certain temporary differences be flowed through immediately to customers. Therefore, certain deferred tax amounts that would otherwise have been recognized in income tax expense have been included as changes in regulatory assets in recognition of MidAmerican Energy's ability to recover increased tax expense when such temporary differences reverse. This treatment of such temporary differences impacts income tax expense and effective income tax rates from year to year.

Federal renewable electricity production tax credits are earned as energy from qualifying wind-powered generating facilities is produced and sold based on a prescribed per-kilowatt rate pursuant to the applicable federal income tax law and are eligible for the credits for 10 years from the date the qualifying generating facilities are placed in service. A portion of MidAmerican Energy's credits related to wind-powered generating facilities placed in service in 2004 began expiring in late 2014. A credit of $0.023 per kilowatt hour was applied to 2015, 2014 and 2013 production, which resulted in $210 million, $183 million and $172 million, respectively, in recognized production tax credits.

MidAmerican Funding -

MidAmerican Funding's income tax benefit was $144 million, $110 million and $110 million for 2015, 2014 and 2013, respectively, and effective tax rates were (46)%, (37)% and (48)% for 2015, 2014 and 2013, respectively. The change in effective tax rates was due principally to the factors discussed for MidAmerican Energy.

Liquidity and Capital Resources

As of December 31, 2015, MidAmerican Energy's total net liquidity was $513 million consisting of $103 million of cash and cash equivalents and $605 million of credit facilities reduced by $195 million of the credit facilities reserved to support MidAmerican Energy's variable-rate tax-exempt bond obligations. As of December 31, 2015, MidAmerican Funding's total net liquidity was $517 million, including MHC's $4 million credit facility.

Cash Flows From Operating Activities

MidAmerican Energy's net cash flows from operating activities were $1.4 billion, $823 million and $735 million for 2015, 2014 and 2013, respectively. MidAmerican Funding's net cash flows from operating activities were $1.3 billion, $820 million and $721 million for 2015, 2014 and 2013, respectively. The variances in net cash flows were predominantly due to the timing of MidAmerican Energy's income tax cash flows with BHE, which totaled net cash receipts from BHE of $629 million, $149 million and $36 million for 2015, 2014 and 2013, respectively. Income tax cash flows for 2015 reflect the receipt of $255 million of income tax benefits generated in 2014, and income tax cash flows for 2013 reflect the payment of $159 million of income tax liability generated in 2012. The timing of MidAmerican Energy's income tax cash flows from period to period can be significantly affected by the estimated federal income tax payment methods and assumptions for each payment date.

In addition to the effects of timing, MidAmerican Energy's income tax cash flows benefited in 2015 from bonus depreciation on qualifying assets placed in service and from production tax credits earned on qualifying projects as a result of the Tax Increase Prevention Act of 2014 (the "Act"), which was signed into law in December 2014. The Act extended to 2015 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. Production tax credits were extended for wind power and other forms of non-solar renewable energy projects that began construction before the end of 2014.

Additionally, cash flows from operations for 2015 improved due to higher gross margins for MidAmerican Energy's regulated electric business and lower derivative collateral requirements, partially offset by an increase in coal inventories and lower gross margins for the regulated gas and nonregulated gas businesses. Cash flows from operations for 2014 also increased from higher gross margins for regulated electric and regulated gas businesses, partially offset by greater collateral requirements related to derivative positions and higher interest paid as a result of the issuance of long-term debt in 2013 and 2014.

In December 2015, the Protecting Americans from Tax Hikes Act of 2015 ("PATH") was signed into law, extending bonus depreciation for qualifying property acquired and placed in service before January 1, 2020 (bonus depreciation rates will be 50% for 2015-2017, 40% in 2018, and 30% in 2019), with an additional year for certain longer lived assets. Production tax credits were extended and phased-out for wind power and other forms of non-solar renewable energy projects that begin construction before the end of 2019. Production tax credits are maintained at full value through 2016, at 80% of present value in 2017, at 60% of present value in 2018, and 40% of present value in 2019. Investment Tax Credits were extended and phased-down for solar projects that are under construction before the end of 2021 (investment tax credit rates are 30% through 2019, 26% in 2020 and 22% in 2021; they revert to the statutory rate of 10% thereafter). As a result of PATH, MidAmerican Energy's cash flows from operations are expected to benefit in 2016 and beyond due to bonus depreciation on qualifying assets placed in service and for production tax credits earned on qualifying wind projects.

Cash Flows From Investing Activities

MidAmerican Energy's net cash flows from investing activities were $(1.5) billion, $(1.5) billion and $(1.0) billion for 2015, 2014 and 2013, respectively. MidAmerican Funding's net cash flows from investing activities were $(1.4) billion, $(1.5) billion and $(1.0) billion for 2015, 2014 and 2013, respectively. Net cash flows from investing activities consist almost entirely of utility construction expenditures, which were relatively unchanged for 2015 compared to 2014 as lower expenditures for environmental and other generation were substantially offset by higher expenditures for wind-powered generation construction and MidAmerican Energy's transmission Multi-Value Projects ("MVP") investments. Utility construction expenditures increased for 2014 primarily due to higher expenditures for the construction of wind-powered generating facilities and transmission MVP investments. MidAmerican Energy placed in service 608 MW, 511 MW and 44 MW of wind-powered generating facilities during 2015, 2014 and 2013, respectively. Purchases and proceeds related to available-for-sale securities consist of activity within the Quad Cities nuclear decommissioning trust. MidAmerican Funding received $13 million in 2015 related to the sale of an investment in a generating facility lease.

Cash Flows From Financing Activities

MidAmerican Energy's net cash flows from financing activities were $173 million, $533 million and $117 million for 2015, 2014 and 2013, respectively. MidAmerican Funding's net cash flows from financing activities were $176 million, $535 million and $131 million for 2015, 2014 and 2013, respectively. In October 2015, MidAmerican Energy issued $200 million of 3.50% First Mortgage Bonds due October 2024 and $450 million of 4.25% First Mortgage Bonds due May 2046. The net proceeds were used for the payment of a $426 million turbine purchase obligation due December 2015 and for general corporate purposes. In April 2014, MidAmerican Energy issued $150 million of 2.40% First Mortgage Bonds due March 2019, $300 million of 3.50% First Mortgage Bonds due October 2024 and $400 million of 4.40% First Mortgage Bonds due October 2044. The net proceeds were used for the optional redemption in May 2014 of $350 million of MidAmerican Energy's 4.65% Senior Notes due October 2014 and for general corporate purposes. Through its commercial paper program, MidAmerican Energy made repayments totaling $50 million in 2015 and received $50 million in 2014. In September 2013, MidAmerican Energy issued $350 million of 2.40% First Mortgage Bonds due March 2019, $250 million of 3.70% First Mortgage Bonds due September 2023 and $350 million of 4.80% First Mortgage Bonds due September 2043. The net proceeds were used for the payment of a $669 million turbine purchase obligation due December 2013 and for general corporate purposes. In January 2013, MidAmerican Energy paid common dividends of $125 million to MHC Inc. and, in April 2013, paid $28 million for the redemption of all outstanding shares of its preferred securities. MidAmerican Funding received $3 million in 2015, paid $1 million in 2014 and received $111 million in 2013 through its note payable with BHE.

Debt Authorizations and Related Matters

MidAmerican Energy has authority from the FERC to issue through June 30, 2016, commercial paper and bank notes aggregating $605 million at interest rates not to exceed the applicable London Interbank Offered Rate ("LIBOR") plus a spread of 400 basis points. MidAmerican Energy has a $600 million unsecured credit facility expiring in March 2018. MidAmerican Energy may request that the banks extend the credit facility up to two years. The credit facility, which supports MidAmerican Energy's commercial paper program and its variable-rate tax-exempt bond obligations and provides for the issuance of letters of credit, has a variable interest rate based on LIBOR or a base rate, at MidAmerican Energy's option, plus a spread that varies based on MidAmerican Energy's credit ratings for senior unsecured long-term debt securities. Additionally, MidAmerican Energy has a $5 million unsecured credit facility for general corporate purposes.

MidAmerican Energy currently has an effective registration statement with the SEC to issue an indeterminate amount of long-term debt securities through September 16, 2018. Additionally, following the October 2015 debt issuances, MidAmerican Energy has authorization from the FERC to issue through March 31, 2017, long-term securities totaling up to $1.05 billion at interest rates not to exceed the applicable United States Treasury rate plus a spread of 175 basis points and from the ICC to issue up to an aggregate of $900 million of additional long-term debt securities, of which $150 million expires December 9, 2016, and $750 million expires September 22, 2018.

In conjunction with the March 1999 merger, MidAmerican Energy committed to the IUB to use commercially reasonable efforts to maintain an investment grade rating on its long-term debt and to maintain its common equity level above 42% of total capitalization unless circumstances beyond its control result in the common equity level decreasing to below 39% of total capitalization. MidAmerican Energy must seek the approval of the IUB of a reasonable utility capital structure if MidAmerican Energy's common equity level decreases below 42% of total capitalization, unless the decrease is beyond the control of MidAmerican Energy. MidAmerican Energy is also required to seek the approval of the IUB if MidAmerican Energy's equity level decreases to below 39%, even if the decrease is due to circumstances beyond the control of MidAmerican Energy. If MidAmerican Energy's common equity level were to drop below the required thresholds, MidAmerican Energy's ability to issue debt could be restricted. As of December 31, 2015, MidAmerican Energy's common equity ratio was 52% computed on a basis consistent with its commitment. As a result of MidAmerican Energy's regulatory commitment to maintain its common equity above certain thresholds, MidAmerican Energy could dividend $1.6 billion as of December 31, 2015, without falling below 42%, and MidAmerican Funding had restricted net assets of $3.1 billion.

MidAmerican Funding or one of its subsidiaries, including MidAmerican Energy, 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 MidAmerican Funding or one of its subsidiaries may be reissued or resold by MidAmerican Funding or one of its subsidiaries from time to time and will depend on prevailing market conditions, the issuing company's liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Future Uses of Cash

MidAmerican Energy and MidAmerican Funding have 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, 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 MidAmerican Energy and MidAmerican Funding have access to external financing depends on a variety of factors, including their credit ratings, investors' judgment of risk and conditions in the overall capital markets, including the condition of the utility industry.

Capital Expenditures

MidAmerican Energy's primary need for capital is utility construction expenditures. 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.

MidAmerican Energy's historical and forecast 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			Forecast		
	2013	**2014**	**2015**	**2016**	**2017**	**2018**
Wind-powered generation development	$ 401	$ 767	$ 931	$ 808	$ 1	$ —
Transmission Multi-Value Projects investments	20	144	156	118	32	21
Environmental	171	76	20	19	103	74
Other	434	539	339	258	465	305
Total	$ 1,026	$ 1,526	$ 1,446	$ 1,203	$ 601	$ 400

MidAmerican Energy's historical and forecast capital expenditures include the following:

- The construction of wind-powered generating facilities in Iowa. As of December 31, 2015, MidAmerican Energy had 3,448 MW (nominal ratings) placed in service. In April 2015, MidAmerican Energy filed with the IUB an application for ratemaking principles related to the construction of up to 552 MW (nominal ratings) of additional wind-powered generating facilities expected to be placed in service by the end of 2016. In June 2015, MidAmerican Energy and the Iowa Office of Consumer Advocate ("OCA") entered into a settlement agreement relating to the proposal. The settlement agreement established a cost cap of $903 million, including AFUDC, and provides for a fixed rate of return on equity of 11.35% over the proposed 30-year useful lives of those facilities in any future Iowa rate proceeding. In August 2015, the IUB approved the settlement agreement except for a reduction of the cost cap to $889 million, including AFUDC, to which MidAmerican Energy and the OCA agreed. The cost cap ensures that as long as total costs are below the cap, the investment will be deemed prudent in any future Iowa rate proceeding. MidAmerican Energy expects all of these wind-powered generating facilities to qualify for federal production tax credits. MidAmerican Energy continues to evaluate additional cost effective wind-powered generation.
- Transmission MVPs investments, which will add approximately 245 miles of 345 kV transmission line to MidAmerican Energy's transmission system and will be owned and operated by MidAmerican Energy. MidAmerican Energy has approval from the MISO for the construction of four MVPs located in Iowa and Illinois totaling approximately $541 million in capital expenditures, excluding non-cash equity AFUDC.
- Environmental projects, which for historical capital expenditures were primarily at George Neal Energy Center Units 3 and 4 and Ottumwa Generating Station to install or upgrade emissions control equipment for the reduction of sulfur dioxide, nitrogen oxides and particulate matter emissions. Forecast amounts for environmental projects consist primarily of expenditures for the management of coal combustion residuals. Refer to "Coal Combustion Byproduct Disposal" in the Environmental Laws and Regulation section later in this Item 7 for further discussion.
- Remaining expenditures primarily relate to routine operating projects for distribution, generation, transmission and other infrastructure needed to serve existing and expected demand.

Contractual Obligations

MidAmerican Energy and MidAmerican Funding have contractual cash obligations that may affect their financial condition. The following table summarizes the material contractual cash obligations of MidAmerican Energy and MidAmerican Funding as of December 31, 2015 (in millions):

	Payments Due By Periods				
	2016	2017-2018	2019-2020	2021 and After	Total
MidAmerican Energy:					
Long-term debt	$ 34	$ 605	$ 501	$ 3,162	$ 4,302
Interest payments on long-term debt[1] [2]	191	356	296	2,279	3,122
Coal, electricity and natural gas contract commitments[1]	334	326	70	88	818
Construction obligations[1]	535	10	—	—	545
Easements and operating leases[1]	17	34	30	516	597
Other commitments[1]	47	130	147	265	589
	1,158	1,461	1,044	6,310	9,973
MidAmerican Funding parent:					
Long-term debt	—	—	—	325	325
Interest payments on long-term debt[1]	23	45	45	191	304
	23	45	45	516	629
Total contractual cash obligations	$ 1,181	$ 1,506	$ 1,089	$ 6,826	$ 10,602

(1) Not reflected on the Consolidated Balance Sheets.

(2) Includes interest payments 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, 2015 rates.

MidAmerican Energy has other types of commitments that relate primarily to construction expenditures (in "Utility Construction Expenditures" section above) and asset retirement obligations (Note 11), which have not been included in the above table because the amount or timing of the cash payments is not certain. Refer to Notes 8, 11 and 14 in Notes to Financial Statements in Item 8 of this Form 10-K for additional information.

Regulatory Matters

MidAmerican Energy is subject to comprehensive regulation. Refer to the discussion contained in Item 1 of this Form 10-K for further discussion regarding MidAmerican Energy's general regulatory framework and current regulatory matters.

Quad Cities Station Operating Status

Exelon Generation, the operator of Quad Cities Station of which MidAmerican Energy has a 25% ownership interest, has stated that it is evaluating the economic value of several of its nuclear generating facilities, including Quad Cities Station. Included in such evaluation is the possibility of early retirement of Quad Cities Station prior to the expiration of its operating license in 2032. Exelon Generation has not provided MidAmerican Energy with notice of any decision to retire Quad Cities Station. MidAmerican Energy has expressed to Exelon Generation its desire for the continued operation of the facility through the end of its operating license.

A decision by Exelon Generation to retire Quad Cities Station before the end of its operating license would require an evaluation of the carrying value and classification of assets and liabilities related to Quad Cities Station on MidAmerican Energy’s balance sheets.

The following significant assets and liabilities associated with Quad Cities Station were included on MidAmerican Energy's balance sheet as of December 31, 2015 (in millions):

Assets:		
Net plant in service, including nuclear fuel	$	332
Construction work in progress		27
Inventory		18
Regulatory assets		4
Liabilities:		
Asset retirement obligation[(1)]		289

(1) MidAmerican Energy's nuclear decommissioning trust fund established for the settlement of the Quad Cities Station asset retirement obligation totaled $429 million as of December 31, 2015.

Environmental Laws and Regulations

MidAmerican Energy is subject to federal, state and local laws and regulations regarding air and water quality, 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 its 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. 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 MidAmerican Energy is unable to predict the impact of the changing laws and regulations on its operations and financial results. MidAmerican Energy believes it is in material compliance with all applicable laws and regulations.

Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for additional information regarding environmental laws and regulations and "Liquidity and Capital Resources" for MidAmerican Energy's forecast environmental-related capital expenditures.

Collateral and Contingent Features

Debt securities of MidAmerican Energy are rated by credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of MidAmerican Energy's ability to, in general, meet the obligations of its issued debt 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, 2015, MidAmerican Energy'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. As a result of the issuance of first mortgage bonds by MidAmerican Energy in September 2013, its then outstanding senior unsecured debt was equally and ratably secured with such first mortgage bonds. Refer to Note 8 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K for a discussion of MidAmerican Energy's first mortgage bonds.

MidAmerican Funding and MidAmerican Energy have no credit rating downgrade triggers that would accelerate the maturity dates of its outstanding debt, and a change in ratings is not an event of default under the applicable debt instruments. MidAmerican Energy'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.

In accordance with industry practice, certain wholesale agreements, including derivative contracts, contain credit support provisions that in part base MidAmerican Energy's collateral requirements on its 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," or in some cases terminate the contract, in the event of a material adverse change in MidAmerican Energy'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, 2015, MidAmerican Energy would have been required to post $258 million of additional collateral. MidAmerican Energy'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 12 of Notes to Financial Statements in Item 8 of this Form 10-K for a discussion of MidAmerican Energy's collateral requirements specific to its 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.

MidAmerican Energy 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 MidAmerican Energy. 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. MidAmerican Energy qualifies or believes it will qualify for many of these exemptions. MidAmerican Energy 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 MidAmerican Energy or could have impacts to energy and other markets in general that could have an impact on MidAmerican Energy's financial results.

Inflation

Historically, overall inflation and changing prices in the economies where MidAmerican Energy operates have not had a significant impact on its financial results. MidAmerican Energy operates under cost-of-service based rate structures administered by various state commissions and the FERC. Under these rate structures, MidAmerican Energy is allowed to include prudent costs in its rates, including the impact of inflation. MidAmerican Energy attempts to minimize the potential impact of inflation on its operations through the use of fuel, energy and other cost adjustment clauses and bill riders, by employing prudent risk management and hedging strategies and by considering, among other areas, inflations 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.

New Accounting Pronouncements

For a discussion of new accounting pronouncements affecting MidAmerican Energy and MidAmerican Funding, 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 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 MidAmerican Energy's methods, judgments and assumptions used in the preparation of the Financial Statements and should be read in conjunction with MidAmerican Energy's Summary of Significant Accounting Policies included in Note 2 of Notes to Financial Statements in Item 8 of this Form 10-K.

Accounting for the Effects of Certain Types of Regulation

MidAmerican Energy prepares its financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, MidAmerican Energy 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 regulated 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 regulated rates occur.

MidAmerican Energy continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future regulated 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 MidAmerican Energy's ability to recover its costs. MidAmerican Energy believes the application of the guidance for regulated operations is appropriate, and its existing regulatory assets and liabilities are probable of inclusion in future regulated 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 regulated rates, the related regulatory assets and liabilities will be written off to net income, returned to customers or re-established as accumulated other comprehensive income (loss) ("AOCI"). Total regulatory assets were $1.0 billion and total regulatory liabilities were $831 million as of December 31, 2015. Refer to Note 5 of Notes to Financial Statements in Item 8 of this Form 10-K for additional information regarding regulatory assets and liabilities.

Income Taxes

In determining MidAmerican Funding's and MidAmerican Energy's income taxes, management is required to interpret complex income tax laws and regulations, which includes consideration of regulatory implications imposed by MidAmerican Energy's various regulatory jurisdictions. MidAmerican Funding's and MidAmerican Energy's income tax returns are subject to continuous examinations by federal, state and local tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. MidAmerican Funding and MidAmerican Energy recognize 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 their federal, state and local tax examinations is uncertain, each company believes it has made adequate provisions for its 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 its consolidated financial results. Refer to Note 9 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding income taxes.

MidAmerican Energy is required to pass income tax benefits related to certain property-related basis differences and other various differences on to its customers in Iowa. These amounts were recognized as a net regulatory asset totaling $858 million as of December 31, 2015, and will be included in regulated rates when the temporary differences reverse.

Impairment of Goodwill

MidAmerican Funding's Consolidated Balance Sheet as of December 31, 2015, includes goodwill from the acquisition of MHC totaling $1.3 billion. Goodwill is allocated to each reporting unit. MidAmerican Funding evaluates goodwill for impairment at least annually and completed its annual review as of October 31. Additionally, no indicators of impairment were identified as of December 31, 2015. Significant judgment is required in estimating the fair value of the reporting unit and performing goodwill impairment tests. MidAmerican Funding uses a variety of methods to estimate a reporting unit's fair value, principally discounted projected future net cash flows. Key assumptions used include, but are not limited to, the use of estimated future cash flows; multiples of earnings; and an appropriate discount rate. Estimated future cash flows are impacted by, among other factors, growth rates, changes in regulations and rates, ability to renew contracts and estimates of future commodity prices. In estimating future cash flows, MidAmerican Funding incorporates current market information, as well as historical factors.

Pension and Other Postretirement Benefits

MidAmerican Energy sponsors defined benefit pension and other postretirement benefit plans that cover the majority of the employees of BHE and its domestic energy subsidiaries other than PacifiCorp and NV Energy Inc. MidAmerican Energy recognizes the funded status of its defined benefit pension and other postretirement benefit plans on the Balance Sheets. Funded status is the fair value of plan assets minus the benefit obligation as of the measurement date. As of December 31, 2015, MidAmerican Energy recognized a net liability totaling $92 million for the funded status of its defined benefit pension and other postretirement benefit plans. As of December 31, 2015, amounts not yet recognized as a component of net periodic benefit cost that were included in regulatory assets totaled $39 million.

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. MidAmerican Energy 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 10 of Notes to Financial Statements in Item 8 of this Form 10-K for disclosures about MidAmerican Energy'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, 2015.

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

MidAmerican Energy 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 10 of Notes to 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 Financial Statements of the total plan before allocations to affiliates would be as follows (in millions):

	Pension Plans		Other Postretirement Benefit Plans	
	+0.5%	-0.5%	+0.5%	-0.5%
Effect on December 31, 2015 Benefit Obligations:				
Discount rate	$ (35)	$ 39	$ (9)	$ 10
Effect on 2015 Periodic Cost:				
Discount rate	1	2	—	1
Expected rate of return on plan assets	(3)	3	(1)	1

A variety of factors affect the funded status of the plans, including asset returns, discount rates, plan changes and MidAmerican Energy's funding policy for each plan.

Revenue Recognition - Unbilled Revenue

Revenue from electric and natural gas customers is recognized as electricity or natural gas is delivered or services are provided. The determination of customer billings is based on a systematic reading of meters and rates. 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 $138 million as of December 31, 2015. 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

MidAmerican Energy's Balance Sheets include assets and liabilities with fair values that are subject to market risks. MidAmerican Energy's significant market risks are primarily associated with commodity prices, interest rates and the extension of credit to counterparties with which it transacts. The following discussion addresses the significant market risks associated with MidAmerican Energy's business activities. MidAmerican Energy has established guidelines for credit risk management. Refer to Notes 2 and 12 of Notes to Financial Statements in Item 8 of this Form 10-K for additional information regarding MidAmerican Energy's contracts accounted for as derivatives.

Commodity Price Risk

MidAmerican Energy is exposed to the impact of market fluctuations in commodity prices and interest rates. MidAmerican Energy is principally exposed to electricity, natural gas, coal and fuel oil commodity price risk as it has an obligation to serve retail customer load in its regulated service territory. MidAmerican Energy has also provided nonregulated retail electricity and natural gas services in competitive markets. MidAmerican Energy'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, wholesale electricity that is purchased and sold, and natural gas supply for retail customers. 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. MidAmerican Energy does not engage in a material amount of proprietary trading activities. To mitigate a portion of its commodity price risk, MidAmerican Energy uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. MidAmerican Energy does not hedge all of its commodity price risk, thereby exposing the unhedged portion to changes in market prices. MidAmerican Energy's exposure to commodity price risk is generally limited by its ability to include commodity costs in regulated rates, which is subject to regulatory lag that occurs between the time the costs are incurred and when the costs are included in regulated rates, as well as the impact of any customer sharing resulting from cost adjustment mechanisms.

The table that follows summarizes MidAmerican Energy's price risk on commodity contracts accounted for as derivatives, excluding collateral netting of $28 million and $47 million, as of December 31, 2015 and 2014, respectively, and shows the effects of a hypothetical 10% increase and 10% decrease in forward market prices with the contracted or expected volumes. 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, 2015:			
Not designated as hedging contracts	$ (26)	$ (18)	$ (34)
Designated as hedging contracts	(46)	(3)	(89)
Total commodity derivative contracts	$ (72)	$ (21)	$ (123)
As of December 31, 2014:			
Not designated as hedging contracts	$ (36)	$ (31)	$ (41)
Designated as hedging contracts	(38)	7	(83)
Total commodity derivative contracts	$ (74)	$ (24)	$ (124)

The majority of MidAmerican Energy's commodity derivative contracts not designated as hedging contracts are recoverable from customers in regulated rates and, therefore, net unrealized gains and losses associated with interim price movements on commodity derivative contracts do not expose MidAmerican Energy to earnings volatility. As of December 31, 2015 and 2014, a net regulatory asset of $20 million and $38 million, respectively, was recorded related to the net derivative liability of $26 million and $36 million, respectively. For MidAmerican Energy's commodity derivative contracts designated as hedging contracts, net unrealized gains and losses associated with interim price movements on commodity derivative contracts, to the extent the hedge is considered effective, generally do not expose MidAmerican Energy to earnings volatility.

Interest Rate Risk

MidAmerican Energy and MidAmerican Funding are exposed to interest rate risk on their outstanding variable-rate short- and long-term debt and future debt issuances. MidAmerican Energy and MidAmerican Funding manage interest rate risk by limiting their 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, the fixed-rate long-term debt does not expose MidAmerican Energy or MidAmerican Funding 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 MidAmerican Energy or MidAmerican Funding were to reacquire all or a portion of these instruments prior to their maturity. MidAmerican Energy or MidAmerican Funding may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate their exposure to interest rate risk. The nature and amount of their 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 7, 8 and 13 of Notes to Consolidated Financial Statements in Item 1 of this Form 10-K for additional discussion of MidAmerican Energy's and MidAmerican Funding's short- and long-term debt.

As of December 31, 2015 and 2014, MidAmerican Energy had short- and long-term variable-rate obligations totaling $195 million and $245 million, respectively, that expose MidAmerican Energy to the risk of increased interest expense in the event of increases in short-term interest rates. The market risk related to MidAmerican Energy's variable-rate debt as of December 31, 2015, is not hedged. If variable interest rates were to increase by 10% from December 31 levels, it would not have a material effect on MidAmerican Energy's annual interest expense. The carrying value of the variable-rate obligations approximates fair value as of December 31, 2015 and 2014.

Credit Risk

MidAmerican Energy 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. Additionally, MidAmerican Energy participates in the regional transmission organization ("RTO") markets and has indirect credit exposure related to other participants, although RTO credit policies are designed to limit exposure to credit losses from individual participants. Credit risk may be concentrated to the extent MidAmerican Energy's counterparties have similar economic, industry or other characteristics and due to direct or indirect relationships among the counterparties. Before entering into a transaction, MidAmerican Energy 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, MidAmerican Energy 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, MidAmerican Energy exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

Substantially all of MidAmerican Energy's electric wholesale sales revenue results from participation in RTOs, including the MISO and the PJM. MidAmerican Energy's share of historical losses from defaults by other RTO market participants has not been material. Additionally, as of December 31, 2015, MidAmerican Energy's aggregate direct credit exposure from electric wholesale marketing counterparties was not material.

Item 8. Financial Statements and Supplementary Data

MidAmerican Energy Company

MidAmerican Funding, LLC and Subsidiaries

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
MidAmerican Energy Company
Des Moines, Iowa

We have audited the accompanying balance sheets of MidAmerican Energy Company ("MidAmerican Energy") as of December 31, 2015 and 2014, and the related statements of operations, comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2015. Our audits also included MidAmerican Energy's financial statement schedule listed in the Index at Item 15(a)(2). These financial statements and financial statement schedule are the responsibility of MidAmerican Energy's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. MidAmerican Energy 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 MidAmerican Energy'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 financial statements present fairly, in all material respects, the financial position of MidAmerican Energy Company as of December 31, 2015 and 2014, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 26, 2016

MIDAMERICAN ENERGY COMPANY
BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2015	**2014**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 103	$ 29
Receivables, net	342	433
Income taxes receivable	104	307
Inventories	238	185
Other current assets	58	86
Total current assets	845	1,040
Property, plant and equipment, net	11,723	10,519
Regulatory assets	1,044	908
Investments and restricted cash and investments	634	625
Other assets	139	142
Total assets	$ 14,385	$ 13,234

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

MIDAMERICAN ENERGY COMPANY
BALANCE SHEETS (continued)
(Amounts in millions)

	As of December 31,	
	2015	**2014**
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Accounts payable	$ 426	$ 392
Accrued interest	46	40
Accrued property, income and other taxes	125	128
Short-term debt	—	50
Current portion of long-term debt	34	426
Other current liabilities	166	131
Total current liabilities	797	1,167
Long-term debt	4,237	3,608
Deferred income taxes	3,061	2,662
Regulatory liabilities	831	837
Asset retirement obligations	488	432
Other long-term liabilities	266	278
Total liabilities	9,680	8,984
Commitments and contingencies (Note 14)		
Shareholder's equity:		
Common stock - 350 shares authorized, no par value, 71 shares issued and outstanding	—	—
Additional paid-in capital	561	561
Retained earnings	4,174	3,712
Accumulated other comprehensive loss, net	(30)	(23)
Total shareholder's equity	4,705	4,250
Total liabilities and shareholder's equity	$ 14,385	$ 13,234

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

MIDAMERICAN ENERGY COMPANY
STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2015	**2014**	**2013**
Operating revenue:			
Regulated electric	$ 1,837	$ 1,817	$ 1,762
Regulated gas	661	996	824
Nonregulated	909	927	817
Total operating revenue	3,407	3,740	3,403
Operating costs and expenses:			
Regulated:			
Cost of fuel, energy and capacity	433	532	517
Cost of gas sold	397	720	558
Operations and maintenance	687	699	659
Depreciation and amortization	407	351	403
Property and other taxes	124	123	119
Nonregulated:			
Cost of sales	855	863	764
Other	33	30	27
Total operating costs and expenses	2,936	3,318	3,047
Operating income	471	422	356
Other income and (expense):			
Interest expense	(183)	(174)	(151)
Allowance for borrowed funds	8	16	7
Allowance for equity funds	20	39	19
Other, net	5	10	16
Total other income and (expense)	(150)	(109)	(109)
Income before income tax benefit	321	313	247
Income tax benefit	(141)	(104)	(103)
Net income	462	417	350
Preferred dividends	—	—	1
Earnings on common stock	$ 462	$ 417	$ 349

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

MIDAMERICAN ENERGY COMPANY
STATEMENTS OF COMPREHENSIVE INCOME
(Amounts in millions)

	Years Ended December 31,		
	2015	2014	2013
Net income	$ 462	$ 417	$ 350
Other comprehensive (loss) income, net of tax:			
Unrealized gains on available-for-sale securities, net of tax of $-, $1 and $1	—	1	1
Unrealized (losses) gains on cash flow hedges, net of tax of $(4), $(10) and $9	(7)	(13)	12
Total other comprehensive (loss) income, net of tax	(7)	(12)	13
Comprehensive income	$ 455	$ 405	$ 363

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

MIDAMERICAN ENERGY COMPANY
STATEMENTS OF CHANGES IN EQUITY
(Amounts in millions)

	MidAmerican Energy Shareholders' Equity				
	Common Stock	Retained Earnings	Accumulated Other Comprehensive Loss, Net	Preferred Securities	Total Equity
Balance, December 31, 2012	$ 562	$ 3,070	$ (24)	$ 27	$ 3,635
Net income	—	350	—	—	350
Other comprehensive income	—	—	13	—	13
Common dividends	—	(125)	—	—	(125)
Redemption of preferred securities	(1)	—	—	(27)	(28)
Balance, December 31, 2013	561	3,295	(11)	—	3,845
Net income	—	417	—	—	417
Other comprehensive loss	—	—	(12)	—	(12)
Balance, December 31, 2014	561	3,712	(23)	—	4,250
Net income	—	462	—	—	462
Other comprehensive loss	—	—	(7)	—	(7)
Balance, December 31, 2015	$ 561	$ 4,174	$ (30)	$ —	$ 4,705

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

MIDAMERICAN ENERGY COMPANY
STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31,		
	2015	**2014**	**2013**
Cash flows from operating activities:			
Net income	$ 462	$ 417	$ 350
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	407	351	403
Deferred income taxes and amortization of investment tax credits	275	300	103
Changes in other assets and liabilities	49	47	57
Other, net	(58)	(57)	(27)
Changes in other operating assets and liabilities:			
Receivables, net	91	(3)	(58)
Inventories	(53)	44	13
Derivative collateral, net	33	(53)	5
Contributions to pension and other postretirement benefit plans, net	(8)	(2)	8
Accounts payable	(76)	30	23
Accrued property, income and other taxes, net	217	(252)	(164)
Other current assets and liabilities	12	1	22
Net cash flows from operating activities	1,351	823	735
Cash flows from investing activities:			
Utility construction expenditures	(1,446)	(1,526)	(1,026)
Purchases of available-for-sale securities	(142)	(88)	(114)
Proceeds from sales of available-for-sale securities	135	80	102
Proceeds from sales of other investments	—	8	15
Other, net	3	5	11
Net cash flows from investing activities	(1,450)	(1,521)	(1,012)
Cash flows from financing activities:			
Common stock dividends	—	—	(125)
Proceeds from long-term debt	649	840	940
Repayments of long-term debt	(426)	(356)	(670)
Redemption of preferred securities	—	—	(28)
Net (repayments of) proceeds from short-term debt	(50)	50	—
Other, net	—	(1)	—
Net cash flows from financing activities	173	533	117
Net change in cash and cash equivalents	74	(165)	(160)
Cash and cash equivalents at beginning of year	29	194	354
Cash and cash equivalents at end of year	$ 103	$ 29	$ 194

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

(1) Company Organization

MidAmerican Energy Company ("MidAmerican Energy") is a public utility with electric and natural gas operations and is the principal subsidiary of MHC Inc. ("MHC"). MHC is a holding company that conducts no business other than the ownership of its subsidiaries and related corporate services. MHC's nonregulated subsidiaries include Midwest Capital Group, Inc. and MEC Construction Services Co. MHC is the direct wholly owned subsidiary of MidAmerican Funding, LLC, ("MidAmerican Funding"), which is an Iowa limited liability company with Berkshire Hathaway Energy Company ("BHE") as its sole member. BHE is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

(2) Summary of Significant Accounting Policies

Use of Estimates in Preparation of Financial Statements

The preparation of the 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 Financial Statements.

Accounting for the Effects of Certain Types of Regulation

MidAmerican Energy's utility operations are subject to the regulation of the Iowa Utilities Board ("IUB"), the Illinois Commerce Commission ("ICC"), the South Dakota Public Utilities Commission, and the Federal Energy Regulatory Commission ("FERC"). MidAmerican Energy's accounting policies and the accompanying Financial Statements conform to GAAP applicable to rate-regulated enterprises and reflect the effects of the ratemaking process.

MidAmerican Energy prepares its financial statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, MidAmerican Energy 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 regulated 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 regulated rates occur.

MidAmerican Energy continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future regulated 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 MidAmerican Energy's ability to recover its costs. MidAmerican Energy believes the application of the guidance for regulated operations is appropriate, and its existing regulatory assets and liabilities are probable of inclusion in future regulated 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 regulated rates, the related regulatory assets and liabilities will be written off to net income, returned to customers or re-established as accumulated other comprehensive income (loss) ("AOCI").

Fair Value Measurements

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

Cash Equivalents and Restricted Cash and Investments

Cash equivalents consist of funds invested in money market mutual funds, United States Treasury Bills and other investments with a maturity of three months or less when purchased. Cash and cash equivalents exclude amounts where availability is restricted by legal requirements, loan agreements or other contractual provisions. Restricted amounts are included in other current assets and investments and nonregulated property, net on the Balance Sheets.

Investments

MidAmerican Energy's management determines the appropriate classification of investments in debt and equity securities at the acquisition date and reevaluates the classification at each balance sheet date. Investments that management does not intend to use or is restricted from using in current operations are presented as noncurrent on the Balance Sheets.

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. Realized and unrealized gains and losses on securities in a trust related to the decommissioning of the Quad Cities Generating Station Units 1 and 2 ("Quad Cities Station") are recorded as a net regulatory liability because MidAmerican Energy expects to recover costs for these activities through regulated rates. Held-to-maturity securities are carried at amortized cost, reflecting the ability and intent to hold the securities to maturity.

Investments gains and losses arise when investments are sold (as determined on a specific identification basis) or are other-than-temporarily impaired. If a decline in value of an investment below cost is deemed other than temporary, the cost of the investment is written down to fair value, with a corresponding charge to earnings. Factors considered in judging whether an impairment is other than temporary include: the financial condition, business prospects and creditworthiness of the issuer; the relative amount of the decline; MidAmerican Energy's ability and intent to hold the investment until the fair value recovers; and the length of time that fair value has been less than cost. Impairment losses on equity securities are charged to earnings. With respect to an investment in a debt security, any resulting impairment loss is recognized in earnings if MidAmerican Energy intends to sell, or expects to be required to sell, the debt security before its amortized cost is recovered. If MidAmerican Energy does not expect to ultimately recover the amortized cost basis even if it does not intend to sell the security, the credit loss component is recognized in earnings and any difference between fair value and the amortized cost basis, net of the credit loss, is reflected in other comprehensive income (loss) ("OCI"). For regulated investments, any impairment charge is offset by the establishment of a regulatory asset to the extent recovery in regulated rates is probable.

Allowance for Doubtful Accounts

Receivables are stated at the outstanding principal amount, net of an estimated allowance for doubtful accounts. The allowance for doubtful accounts is based on MidAmerican Energy's assessment of the collectibility of amounts owed to it by its customers. This assessment requires judgment regarding the ability of customers to pay or the outcome of any pending disputes. As of December 31, 2015 and 2014, the allowance for doubtful accounts totaled $6 million and $7 million, respectively, and is included in receivables, net on the Balance Sheets.

Derivatives

MidAmerican Energy employs a number of different derivative contracts, including forwards, futures, 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 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. Cash collateral received from or paid to counterparties to secure derivative contract assets or liabilities in excess of amounts offset is included in other current assets on the Balance Sheets.

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 cost of sales on the Statements of Operations.

For MidAmerican Energy's derivatives not designated as hedging contracts, the settled amount is generally included in regulated 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 regulated rates are recorded as regulatory assets and liabilities. For MidAmerican Energy's derivatives not designated as hedging contracts and for which changes in fair value are not recorded as regulatory assets and liabilities, unrealized gains and losses are recognized on the Statements of Operations as nonregulated operating revenue for sales contracts and as nonregulated cost of sales for purchase contracts and electricity and natural gas swap contracts.

For MidAmerican Energy's derivatives designated as hedging contracts, MidAmerican Energy formally assesses, at inception and thereafter, whether the hedging contract is highly effective in offsetting changes in the hedged item. MidAmerican Energy formally documents hedging activity by transaction type and risk management strategy.

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

Inventories

Inventories consist mainly of materials and supplies, totaling $105 million and $101 million as of December 31, 2015 and 2014, respectively, coal stocks, totaling $102 million and $54 million as of December 31, 2015 and 2014, respectively, and natural gas in storage, totaling $27 million and $24 million as of December 31, 2015 and 2014, respectively. The cost of materials and supplies, coal stocks and fuel oil is determined using the average cost method. The cost of stored natural gas is determined using the last-in-first-out method. With respect to stored natural gas, the replacement cost would be $8 million and $41 million higher as of December 31, 2015 and 2014, respectively.

Utility Plant, Net

General

Additions to utility plant are recorded at cost. MidAmerican Energy capitalizes all construction-related material, direct labor and contract services, as well as indirect construction costs. Indirect construction costs include debt allowance for funds used during construction ("AFUDC") and equity 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. Additionally, MidAmerican Energy has regulatory arrangements in Iowa in which the carrying cost of certain utility plant has been reduced for amounts associated with electric returns on equity exceeding specified thresholds.

Depreciation and amortization for MidAmerican Energy's utility operations are computed by applying the composite or straight-line method based on either estimated useful lives or mandated recovery periods as prescribed by its various regulatory authorities. Depreciation studies are completed by MidAmerican Energy to determine the appropriate group lives, net salvage and group depreciation rates. These studies are reviewed and rates are ultimately approved by the applicable regulatory commission. 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 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 MidAmerican Energy retires or sells a component of utility plant, it charges the original cost, net of any proceeds from the disposition to accumulated depreciation. Any gain or loss on disposals of nonregulated 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 its regulated facilities, is capitalized by MidAmerican Energy as a component of utility plant, with offsetting credits to the Statements of Operations. AFUDC is computed based on guidelines set forth by the FERC. After construction is completed, MidAmerican Energy 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

MidAmerican Energy recognizes AROs when it has a legal obligation to perform decommissioning or removal activities upon retirement of an asset. MidAmerican Energy's AROs are primarily related to decommissioning of the Quad Cities Station and obligations associated with its other 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 utility plant) 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 utility plant, net and amounts recovered in rates to satisfy such liabilities is recorded as a regulatory asset or liability.

Impairment

MidAmerican Energy evaluates long-lived assets for impairment, including utility plant, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value. The impacts of regulation are considered when evaluating the carrying value of regulated assets. For all other assets, any resulting impairment loss is reflected on the Statements of Operations.

Revenue Recognition

Revenue from electric and natural gas customers is recognized as electricity or natural gas is delivered or services are provided. Revenue recognized includes billed and unbilled amounts. As of December 31, 2015 and 2014, unbilled revenue was $138 million and $131 million, respectively, and is included in receivables, net on the Balance Sheets.

The determination of revenue from an individual customer is based on a systematic reading of meters and rates. At the end of each month, amounts of energy provided to customers since the date of the last meter reading are estimated, and the corresponding unbilled revenue is recorded. Factors that can impact the estimate of unbilled energy include, but are not limited to, seasonal weather patterns compared to normal, total volumes supplied to the system, line losses, economic impacts and composition of customer classes. Estimates are reversed in the following month and actual revenue is recorded based on subsequent meter readings.

All of MidAmerican Energy's regulated retail electric and gas sales are subject to energy adjustment clauses. MidAmerican Energy also has costs that are recovered, at least in part, through bill riders, including demand-side management costs. The clauses and riders allow MidAmerican Energy to adjust the amounts charged for electric and gas service as the related costs change. The costs recovered in revenue through use of the adjustment clauses and bill riders are charged to expense in the same year the related revenue is recognized. At any given time, these costs may be over or under collected from customers. The total under collection included in receivables at December 31, 2015 and 2014, was $17 million and $25 million, respectively.

MidAmerican Energy collects from its customers sales and excise taxes assessed by governmental authorities on transactions with customers and later remits the collected taxes to the appropriate authority. If the obligation to pay a particular tax resides with the customer, MidAmerican Energy reports such taxes collected on a net basis and, accordingly, they do not affect the Statement of Operations. Taxes for which the obligation resides with MidAmerican Energy are reported on a gross basis in operating revenue and operating expenses. The amounts reported on a gross basis are not material.

Unamortized Debt Premiums, Discounts and Issuance Costs

Premiums, discounts and issuance costs incurred for the issuance of long-term debt are amortized over the term of the related financing using the effective interest method.

Income Taxes

Berkshire Hathaway includes MidAmerican Funding and MidAmerican Energy in its United States federal income tax return. MidAmerican Funding's and MidAmerican Energy's provisions for income taxes have been computed on a stand-alone basis, and substantially all of their respective currently payable or receivable income taxes are remitted to or received from BHE.

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 MidAmerican Energy is required to pass on to its customers in Iowa are charged or credited directly to a regulatory asset or liability. As of December 31, 2015 and 2014, these amounts were recognized as a net regulatory asset totaling $858 million and $730 million, respectively, and will be included in regulated 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. Investment tax credits are generally deferred and amortized over the estimated useful lives of the related properties or as prescribed by various regulatory jurisdictions.

In determining MidAmerican Funding's and MidAmerican Energy's income taxes, management is required to interpret complex income tax laws and regulations, which includes consideration of regulatory implications imposed by MidAmerican Energy's various regulatory jurisdictions. MidAmerican Funding's and MidAmerican Energy's income tax returns are subject to continuous examinations by federal, state and local tax authorities that may give rise to different interpretations of these complex laws and regulations. Due to the nature of the examination process, it generally takes years before these examinations are completed and these matters are resolved. MidAmerican Funding and MidAmerican Energy recognize 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 their federal, state and local income tax examinations is uncertain, each company believes it has made adequate provisions for its 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 its consolidated financial results. MidAmerican Funding's and MidAmerican Energy's unrecognized tax benefits are primarily included in taxes accrued and other long-term liabilities on their respective 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.

New Accounting Pronouncements

In January 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2016-01, which amends FASB Accounting Standards Codification ("ASC") Subtopic 825-10, "Financial Instruments - Overall." The amendments in this guidance address certain aspects of recognition, measurement, presentation and disclosure of financial instruments including a requirement that all investments in equity securities that do not qualify for equity method accounting or result in consolidation of the investee be measured at fair value with changes in fair value recognized in net income. This guidance is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption not permitted, and is required to be adopted prospectively by means of a cumulative-effect adjustment to the balance sheet as of the beginning of the fiscal year of adoption. MidAmerican Energy is currently evaluating the impact of adopting this guidance on its Financial Statements and disclosures included within Notes to Financial Statements.

In November 2015, the FASB issued ASU No. 2015-17, which amends FASB ASC Topic 740, "Income Taxes." The amendments in this guidance require that deferred income tax liabilities and assets be classified as noncurrent in the balance sheet. This guidance is effective for interim and annual reporting periods beginning after December 15, 2016, with early adoption permitted, and may be adopted prospectively or retrospectively for each period presented to reflect the new guidance. MidAmerican Energy early adopted this guidance as of December 31, 2015, under a retrospective method, resulting in a decrease of $1 million each in other current assets and noncurrent deferred income tax liabilities as of December 31, 2014.

In April 2015, the FASB issued ASU No. 2015-03, which amends FASB ASC Subtopic 835-30, "Interest - Imputation of Interest." The amendments in this guidance require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability instead of as an asset. This guidance is effective for interim and annual reporting periods beginning after December 15, 2015, with early adoption permitted. This guidance must be adopted retrospectively, wherein the balance sheet of each period presented should be adjusted to reflect the new guidance. MidAmerican Energy early adopted this guidance as of December 31, 2015, under a retrospective method, resulting in a decrease of $22 million each in other assets and long-term debt as of December 31, 2014.

In May 2014, the FASB issued ASU No. 2014-09, which creates FASB 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. MidAmerican Energy is currently evaluating the impact of adopting this guidance on its Financial Statements and disclosures included within Notes to 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	2015	2014
Utility plant in service:			
Generation	20-100 years	$ 10,404	$ 9,351
Transmission	52-70 years	1,305	1,142
Electric distribution	20-70 years	3,059	2,933
Gas distribution	28-70 years	1,507	1,432
Utility plant in service		16,275	14,858
Accumulated depreciation and amortization		(5,229)	(4,954)
Utility plant in service, net		11,046	9,904
Nonregulated property, net:			
Nonregulated property gross	5-45 years	15	14
Accumulated depreciation and amortization		(5)	(5)
Nonregulated property, net		10	9
		11,056	9,913
Construction work in progress		667	606
Property, plant and equipment, net		$ 11,723	$ 10,519

Nonregulated property includes land, computer software and other assets not recoverable for regulated utility purposes.

The average depreciation and amortization rates applied to depreciable utility plant for the years ended December 31 were as follows:

	2015	2014	2013
Electric	3.0%	2.8%	3.3%
Gas	2.9%	2.8%	2.8%

During the third quarter of 2013, MidAmerican Energy revised its depreciation rates for certain electric generating facilities based on the results of a new depreciation study. The new rates reflect longer estimated useful lives for wind-powered generating facilities placed in service in 2011 and 2012 and a lower accrual rate for the cost of removal regulatory liability related to coal-fueled generating facilities. The effect of this change was to reduce depreciation and amortization expense by $20 million in 2013 and $49 million annually based on depreciable plant balances at the time of the change. Effective January 1, 2014, MidAmerican Energy revised depreciation rates for certain electric generating facilities based on the results of its 2013 Iowa electric retail rate case. The new depreciation rates reflect longer estimated useful lives for certain generating facilities. The effect of this change was to reduce depreciation and amortization expense by $50 million annually based on depreciable plant balances at the time of the change.

(4) Jointly Owned Utility Facilities

Under joint facility ownership agreements with other utilities, MidAmerican Energy, as a tenant in common, has undivided interests in jointly owned generation and transmission facilities. MidAmerican Energy 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 Statements of Operations include MidAmerican Energy's share of the expenses of these facilities.

The amounts shown in the table below represent MidAmerican Energy's share in each jointly owned facility as of December 31, 2015 (dollars in millions):

	Company Share	Plant in Service	Accumulated Depreciation and Amortization	Construction Work in Progress
Louisa Unit No. 1	88.0%	$ 757	$ 405	$ 7
Quad Cities Unit Nos. 1 & 2[(1)]	25.0	672	340	27
Walter Scott, Jr. Unit No. 3	79.1	608	297	6
Walter Scott, Jr. Unit No. 4[(2)]	59.7	448	91	—
George Neal Unit No. 4	40.6	305	148	1
Ottumwa Unit No. 1	52.0	554	184	3
George Neal Unit No. 3	72.0	415	153	—
Transmission facilities[(3)]	Various	245	83	2
Total		$ 4,004	$ 1,701	$ 46

(1) Includes amounts related to nuclear fuel.

(2) Plant in service and accumulated depreciation and amortization amounts are net of credits applied under Iowa revenue sharing arrangements totaling $319 million and $67 million, respectively.

(3) Includes 345 and 161 kilovolt transmission lines and substations.

(5) Regulatory Matters

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

	Average Remaining Life	2015	2014
Deferred income taxes, net[(1)]	25 years	$ 858	$ 730
Asset retirement obligations[(2)]	6 years	94	62
Employee benefit plans[(3)]	11 years	39	42
Unrealized loss on regulated derivative contracts	1 year	20	38
Other	Various	33	36
Total		$ 1,044	$ 908

(1) Amounts primarily represent income tax benefits related to state accelerated tax depreciation and certain property-related basis differences that were previously flowed through to customers and will be included in regulated rates when the temporary differences reverse.

(2) Amount predominantly relates to asset retirement obligations for fossil-fueled and wind-powered generating facilities. Refer to Note 11 for a discussion of asset retirement obligations.

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

MidAmerican Energy had regulatory assets not earning a return on investment of $1.0 billion and $904 million as of December 31, 2015 and 2014, respectively.

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

	Average Remaining Life	2015	2014
Cost of removal accrual[1]	25 years	$ 653	$ 642
Asset retirement obligations[2]	22 years	140	159
Other	Various	38	36
Total		$ 831	$ 837

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

(2) Amount predominantly represents the excess of nuclear decommission trust assets over the related asset retirement obligation. Refer to Note 11for a discussion of asset retirement obligations.

(6) Investments and Restricted Cash and Investments

Investments and restricted cash and investments consists of the following amounts as of December 31 (in millions):

	2015	2014
Nuclear decommissioning trust	$ 429	$ 424
Rabbi trusts	175	175
Auction rate securities	26	26
Other	4	—
Total	$ 634	$ 625

MidAmerican Energy has established a trust for the investment of funds for decommissioning the Quad Cities Station. These investments in debt and equity securities are classified as available-for-sale and are reported at fair value. Funds are invested in the trust in accordance with applicable federal and state investment guidelines and are restricted for use as reimbursement for costs of decommissioning the Quad Cities Station, which is currently licensed for operation until December 2032. As of December 31, 2015 and 2014, the fair value of the trust's funds was invested as follows: 56% and 56%, respectively, in domestic common equity securities, 31% and 32%, respectively, in United States government securities, 9% and 9%, respectively, in domestic corporate debt securities and 4% and 3%, respectively, in other securities.

Rabbi trusts primarily hold corporate-owned life insurance on certain current and former key executives and directors. The Rabbi trusts were established to hold investments used to fund the obligations of various nonqualified executive and director compensation plans and to pay the costs of the trusts. The amount represents the cash surrender value of all of the policies included in the Rabbi trusts, net of amounts borrowed against the cash surrender value. Changes in the cash surrender value of the policies are reflected in other income and (expense) - other, net on the Statements of Operation.

MidAmerican Energy has investments in interest bearing auction rate securities with a par value of $35 million as of December 31, 2015 and 2014, and remaining maturities of 2 to 20 years. MidAmerican Energy considers the securities to be temporarily impaired, except for an other-than-temporary impairment of $3 million, after-tax, recorded in 2008, and has recorded unrealized losses on the securities of $3 million and $3 million, after tax, in AOCI as of December 31, 2015 and 2014, respectively. MidAmerican Energy does not intend to sell or expect to be required to sell the securities until the remaining principal investment is collected.

(7) Short-Term Debt and Credit Facilities

Interim financing of working capital needs and the construction program is obtained from unaffiliated parties through the sale of commercial paper or short-term borrowing from banks. MidAmerican Energy has a $600 million unsecured credit facility expiring in March 2018. The credit facility, which supports MidAmerican Energy's commercial paper program and its variable-rate tax-exempt bond obligations and provides for the issuance of letters of credit, has a variable interest rate based on the London Interbank Offered Rate ("LIBOR") or a base rate, at MidAmerican Energy's option, plus a spread that varies based on MidAmerican Energy's credit ratings for senior unsecured long-term debt securities. In addition, MidAmerican Energy has a $5 million unsecured credit facility, which expires in June 2016 and has a variable interest rate based on LIBOR plus a spread. As of December 31, 2014, the weighted average interest rate on commercial paper borrowings outstanding was 0.35%. The $600 million credit facility requires that MidAmerican Energy's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.65 to 1.0 as of the last day of any quarter. As of December 31, 2015, MidAmerican Energy was in compliance with the covenants of its credit facilities. MidAmerican Energy has authority from the FERC to issue commercial paper and bank notes aggregating $605 million through June 30, 2016.

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

	2015	2014
Credit facilities	$ 605	$ 605
Less:		
Short-term debt outstanding	—	(50)
Variable-rate tax-exempt bond support	(195)	(195)
Net credit facilities	$ 410	$ 360

(8) Long-Term Debt

MidAmerican Energy's long-term debt consists of the following, including amounts maturing within one year and unamortized premiums, discounts and debt issuance costs, as of December 31 (dollars in millions):

	Par Value	2015	2014
First mortgage bonds:			
2.40%, due 2019	$ 500	$ 499	$ 498
3.70%, due 2023	250	248	248
3.50%, due 2024	500	502	296
4.80%, due 2043	350	345	345
4.40%, due 2044	400	394	394
4.25%, due 2046	450	444	—
Notes:			
5.95% Series, due 2017	250	250	250
5.3% Series, due 2018	350	349	349
6.75% Series, due 2031	400	395	395
5.75% Series, due 2035	300	298	298
5.8% Series, due 2036	350	347	347
Turbine purchase obligation, 1.43%, due 2015[(1)]	—	—	420
Transmission upgrade obligation, 4.449%, due through 2035	5	4	—
Variable-rate tax-exempt bond obligation series: (weighted average interest rate-2015-0.03%, 2014-0.07%)			
Due 2016	34	33	33
Due 2017	4	4	4
Due 2023, issued in 1993	7	7	7
Due 2023, issued in 2008	57	57	57
Due 2024	35	35	35
Due 2025	13	13	13
Due 2038	45	45	45
Capital lease obligations - 4.16%, due through 2020	2	2	—
Total	$ 4,302	$ 4,271	$ 4,034

(1) In conjunction with the construction of wind-powered generating facilities in 2012, MidAmerican Energy accrued as gross property, plant and equipment amounts for turbine purchases it is not contractually obligated to pay until December 2015. The amount ultimately payable was discounted and recognized upon delivery of the equipment as long-term debt. The discount was amortized as interest expense over the period until payment was due using the effective interest method.

The annual repayments of MidAmerican Energy's long-term debt for the years beginning January 1, 2016, and thereafter, excluding unamortized premiums, discounts and debt issuance costs, are as follows (in millions):

2016	$ 34
2017	254
2018	351
2019	500
2020	1
2021 and thereafter	3,162

MidAmerican Energy issued $650 million of first mortgage bonds in October 2015 pursuant to its indenture dated September 9, 2013, as supplemented and amended. The net proceeds were used for the payment of the $426 million turbine purchase obligation due December 2015 and for general corporate purposes.

Pursuant to MidAmerican Energy's mortgage dated September 9, 2013, MidAmerican Energy's first mortgage bonds, currently and from time to time outstanding, are secured by a first mortgage lien on substantially all of its electric generating, transmission and distribution property within the State of Iowa, subject to certain exceptions and permitted encumbrances. As of December 31, 2015, MidAmerican Energy's eligible property subject to the lien of the mortgage totaled approximately $13 billion based on original cost. Additionally, MidAmerican Energy's senior notes outstanding are equally and ratably secured with the first mortgage bonds as required by the indentures under which the senior notes were issued.

MidAmerican Energy's variable rate tax-exempt obligations, including the tax-exempt bonds discussed below, bear interest at rates that are periodically established through remarketing of the bonds in the short-term tax-exempt market. MidAmerican Energy, at its option, may change the mode of interest calculation for these bonds by selecting from among several floating or fixed rate alternatives. The interest rates shown in the table above are the weighted average interest rates as of December 31, 2015 and 2014. MidAmerican Energy maintains revolving credit facility agreements to provide liquidity for holders of these issues.

As of December 31, 2015, MidAmerican Energy was in compliance with all of its applicable long-term debt covenants.

In March 1999, MidAmerican Energy committed to the IUB to use commercially reasonable efforts to maintain an investment grade rating on its long-term debt and to maintain its common equity level above 42% of total capitalization unless circumstances beyond its control result in the common equity level decreasing to below 39% of total capitalization. MidAmerican Energy must seek the approval from the IUB of a reasonable utility capital structure if MidAmerican Energy's common equity level decreases below 42% of total capitalization, unless the decrease is beyond the control of MidAmerican Energy. MidAmerican Energy is also required to seek the approval of the IUB if MidAmerican Energy's equity level decreases to below 39%, even if the decrease is due to circumstances beyond the control of MidAmerican Energy. As of December 31, 2015, MidAmerican Energy's common equity ratio was 52% computed on a basis consistent with its commitment. As a result of its regulatory commitment to maintain its common equity level above certain thresholds, MidAmerican Energy could dividend $1.6 billion as of December 31, 2015, without falling below 42%.

(9) Income Taxes

MidAmerican Energy's income tax benefit consists of the following for the years ended December 31 (in millions):

	2015	2014	2013
Current:			
Federal	$ (405)	$ (401)	$ (196)
State	(10)	(3)	(10)
	(415)	(404)	(206)
Deferred:			
Federal	281	299	101
State	(6)	2	3
	275	301	104
Investment tax credits	(1)	(1)	(1)
Total	$ (141)	$ (104)	$ (103)

A reconciliation of the federal statutory income tax rate to MidAmerican Energy's effective income tax rate applicable to income before income tax benefit is as follows for the years ended December 31:

	2015	2014	2013
Federal statutory income tax rate	35 %	35 %	35 %
Income tax credits	(65)	(59)	(70)
State income tax, net of federal income tax benefit	(3)	—	(2)
Effects of ratemaking	(12)	(8)	(3)
Other, net	1	(1)	(2)
Effective income tax rate	(44)%	(33)%	(42)%

Income tax credits relate primarily to production tax credits earned by MidAmerican Energy's wind-powered generating facilities. Federal renewable electricity production tax credits are earned as energy from qualifying wind-powered generating facilities is produced and sold and are based on a per-kilowatt hour rate pursuant to the applicable federal income tax law. Wind-powered generating facilities are eligible for the credits for 10 years from the date the qualifying generating facilities are placed in service.

MidAmerican Energy's net deferred income tax liability consists of the following as of December 31 (in millions):

	2015	2014
Deferred income tax assets:		
Regulatory liabilities	$ 327	$ 332
Employee benefits	66	68
Derivative contracts	29	30
Asset retirement obligations	214	185
Other	59	59
Total deferred income tax assets	695	674
Deferred income tax liabilities:		
Depreciable property	(3,321)	(2,945)
Regulatory assets	(418)	(366)
Other	(17)	(25)
Total deferred income tax liabilities	(3,756)	(3,336)
Net deferred income tax liability	$ (3,061)	$ (2,662)

As of December 31, 2015, MidAmerican Energy has available $23 million of state carryforwards, principally related to $488 million of net operating losses, that expire at various intervals between 2016 and 2034.

The United States Internal Revenue Service has closed its examination of BHE's income tax returns through December 2009, including components related to MidAmerican Energy. In addition, state jurisdictions have closed their examinations of MidAmerican Energy's income tax returns through at least February 9, 2006, including Iowa and Illinois, which are closed through December 31, 2012, and December 31, 2008, respectively.

A reconciliation of the beginning and ending balances of MidAmerican Energy's net unrecognized tax benefits is as follows for the years ended December 31 (in millions):

	2015	2014
Beginning balance	$ 26	$ 29
Additions based on tax positions related to the current year	3	6
Additions for tax positions of prior years	47	38
Reductions based on tax positions related to the current year	(6)	(4)
Reductions for tax positions of prior years	(46)	(40)
Statute of limitations	(5)	(3)
Settlements	(6)	—
Interest and penalties	(3)	—
Ending balance	$ 10	$ 26

As of December 31, 2015, MidAmerican Energy had unrecognized tax benefits totaling $26 million that, if recognized, would have an impact on the effective tax rate. The remaining unrecognized tax benefits relate 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 MidAmerican Energy's effective income tax rate.

(10) Employee Benefit Plans

MidAmerican Energy sponsors a noncontributory defined benefit pension plan covering a majority of all employees of BHE and its domestic energy subsidiaries other than PacifiCorp and NV Energy, Inc. Benefit obligations under the plan are based on a cash balance arrangement for salaried employees and most union employees and final average pay formulas for other union employees. MidAmerican Energy also maintains noncontributory, nonqualified defined benefit supplemental executive retirement plans ("SERP") for certain active and retired participants.

MidAmerican Energy also sponsors certain postretirement healthcare and life insurance benefits covering substantially all retired employees of BHE and its domestic energy subsidiaries other than PacifiCorp and NV Energy, Inc. Under the plans, a majority of all employees of the participating companies may become eligible for these benefits if they reach retirement age. New employees are not eligible for benefits under the plans. MidAmerican Energy has been allowed to recover accrued pension and other postretirement benefit costs in its electric and gas service rates.

Net Periodic Benefit Cost

For purposes of calculating the expected return on pension 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 on equity investments over a five-year period beginning after the first year in which they occur.

MidAmerican Energy bills to and is reimbursed currently for affiliates' share of the net periodic benefit costs from all plans in which such affiliates participate. In 2015, 2014 and 2013, MidAmerican Energy's share of the pension net periodic benefit cost (credit) was $(4) million, $1 million and $11 million, respectively. MidAmerican Energy's share of the other postretirement net periodic benefit cost (credit) in 2015, 2014 and 2013 totaled $- million, $- million and $(1) million, respectively.

Net periodic benefit cost for the plans of MidAmerican Energy and the aforementioned affiliates included the following components for the years ended December 31 (in millions):

	Pension			Other Postretirement		
	2015	2014	2013	2015	2014	2013
Service cost	$ 12	$ 14	$ 18	$ 7	$ 6	$ 5
Interest cost	32	35	33	9	10	8
Expected return on plan assets	(46)	(45)	(45)	(15)	(15)	(13)
Net amortization	2	1	11	(3)	(3)	(3)
Net periodic benefit cost (credit)	$ —	$ 5	$ 17	$ (2)	$ (2)	$ (3)

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	
	2015	2014	2015	2014
Plan assets at fair value, beginning of year	$ 730	$ 722	$ 259	$ 256
Employer contributions	7	7	1	1
Participant contributions	—	—	1	1
Actual return on plan assets	4	52	—	13
Benefits paid	(63)	(51)	(12)	(12)
Plan assets at fair value, end of year	$ 678	$ 730	$ 249	$ 259

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

	Pension		Other Postretirement	
	2015	2014	2015	2014
Benefit obligation, beginning of year	$ 840	$ 768	$ 249	$ 235
Service cost	12	14	7	6
Interest cost	32	35	9	10
Participant contributions	—	—	1	1
Actuarial (gain) loss	(36)	74	(20)	9
Benefits paid	(63)	(51)	(12)	(12)
Benefit obligation, end of year	$ 785	$ 840	$ 234	$ 249
Accumulated benefit obligation, end of year	$ 773	$ 825		

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

	Pension		Other Postretirement	
	2015	2014	2015	2014
Plan assets at fair value, end of year	$ 678	$ 730	$ 249	$ 259
Less - Benefit obligation, end of year	785	840	234	249
Funded status	$ (107)	$ (110)	$ 15	$ 10
Amounts recognized on the Balance Sheets:				
Other assets	$ 7	$ 12	$ 15	$ 10
Other current liabilities	(8)	(8)	—	—
Other liabilities	(106)	(114)	—	—
Amounts recognized	$ (107)	$ (110)	$ 15	$ 10

The SERP has no plan assets; however, MidAmerican Energy and BHE have Rabbi trusts that hold 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 trusts, net of amounts borrowed against the cash surrender value, plus the fair market value of other Rabbi trust investments, was $156 million and $156 million as of December 31, 2015 and 2014, respectively, of which $104 million and $103 million was held by MidAmerican Energy as of December 31, 2015 and 2014, respectively, with the remainder held by BHE. These assets are not included in the plan assets in the above table, but are reflected in investments and nonregulated property, net on the 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	
	2015	2014	2015	2014
Net loss	$ 26	$ 21	$ 42	$ 49
Prior service cost (credit)	2	3	(36)	(42)
Total	$ 28	$ 24	$ 6	$ 7

MidAmerican Energy sponsors pension and other postretirement benefit plans on behalf of certain of its affiliates in addition to itself, and therefore, the portion of the funded status of the respective plans that has not yet been recognized in net periodic benefit cost is attributable to multiple entities. Additionally, substantially all of MidAmerican Energy's portion of such amounts is either refundable to or recoverable from its customers and is reflected as regulatory liabilities and regulatory assets.

A reconciliation of the amounts not yet recognized as components of net periodic benefit cost for the years ended December 31, 2015 and 2014 is as follows (in millions):

	Regulatory Asset	Regulatory Liability	Receivables (Payables) with Affiliates	Total
Pension				
Balance, December 31, 2013	$ 16	$ (55)	$ (2)	$ (41)
Net loss arising during the year	6	51	9	66
Net amortization	—	(1)	—	(1)
Total	6	50	9	65
Balance, December 31, 2014	22	(5)	7	24
Net loss (gain) arising during the year	2	5	(1)	6
Net amortization	(2)	—	—	(2)
Total	—	5	(1)	4
Balance, December 31, 2015	$ 22	$ —	$ 6	$ 28

	Regulatory Asset	Regulatory Liability	Receivables (Payables) with Affiliates	Total
Other Postretirement				
Balance, December 31, 2013	$ 10	$ —	$ (16)	$ (6)
Net loss arising during the year	8	—	2	10
Net amortization	2	—	1	3
Total	10	—	3	13
Balance, December 31, 2014	20	—	(13)	7
Net gain arising during the year	(5)	—	—	(5)
Net amortization	2	—	2	4
Total	(3)	—	2	(1)
Balance, December 31, 2015	$ 17	$ —	$ (11)	$ 6

The net loss and prior service cost (credit) that will be amortized in 2016 into net periodic benefit cost are estimated to be as follows (in millions):

	Net Loss	Prior Service Cost (Credit)	Total
Pension	$ 1	$ 1	$ 2
Other postretirement	2	(6)	(4)
Total	$ 3	$ (5)	$ (2)

Plan Assumptions

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

	Pension			Other Postretirement		
	2015	2014	2013	2015	2014	2013
Benefit obligations as of December 31:						
Discount rate	4.50%	4.00%	4.75%	4.25%	3.75%	4.50%
Rate of compensation increase	2.75%	2.75%	3.00%	N/A	N/A	N/A
Net periodic benefit cost for the years ended December 31:						
Discount rate	4.00%	4.75%	4.00%	3.75%	4.50%	3.75%
Expected return on plan assets[(1)]	7.25%	7.50%	7.50%	7.00%	7.25%	7.25%
Rate of compensation increase	2.75%	3.00%	3.00%	N/A	N/A	N/A

(1) Amounts reflected are pre-tax values. Assumed after-tax returns for a taxable, non-union other postretirement plan were 5.18% for 2015, and 5.37% for 2014, and 5.56% for 2013.

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

	2015	2014
Assumed healthcare cost trend rates as of December 31:		
Healthcare cost trend rate assumed for next year	7.70%	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	2025

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

	One Percentage-Point	
	Increase	Decrease
Increase (decrease) in:		
Total service and interest cost for the year ended December 31, 2015	$ 1	$ —
Other postretirement benefit obligation as of December 31, 2015	3	(3)

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be $8 million and $1 million, respectively, during 2016. Funding to MidAmerican Energy's pension benefit 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 and the Pension Protection Act of 2006, as amended. MidAmerican Energy considers contributing additional amounts from time to time in order to achieve certain funding levels specified under the Pension Protection Act of 2006, as amended. MidAmerican Energy's funding policy for its other postretirement benefit plan is to generally contribute amounts consistent with its rate regulatory arrangements.

Net periodic benefit costs assigned to MidAmerican Energy affiliates are reimbursed currently in accordance with its intercompany administrative services agreement. The expected benefit payments to participants in MidAmerican Energy's pension and other postretirement benefit plans for 2016 through 2020 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments	
	Pension	Other Postretirement
2016	$ 59	$ 17
2017	60	19
2018	60	20
2019	60	21
2020	61	21
2021-2025	291	102

Plan Assets

Investment Policy and Asset Allocations

MidAmerican Energy'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 MidAmerican Energy Pension and Employee Benefits Plans Administrative 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 MidAmerican Energy's pension and other postretirement benefit plan assets are as follows as of December 31, 2015:

	Pension	Other Postretirement
	%	%
Debt securities(1)	20-40	25-45
Equity securities(1)	60-80	50-80
Real estate funds	2-8	—
Other	0-5	0-5

(1) 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 MidAmerican Energy's defined benefit pension plan (in millions):

	Input Levels for Fair Value Measurements[1]			
	Level 1	Level 2	Level 3	Total
As of December 31, 2015				
Cash equivalents	$ —	$ 16	$ —	$ 16
Debt securities:				
United States government obligations	5	—	—	5
Corporate obligations	—	57	—	57
Municipal obligations	—	6	—	6
Agency, asset and mortgage-backed obligations	—	27	—	27
Equity securities:				
United States companies	130	—	—	130
International equity securities	40	—	—	40
Investment funds[2]	61	289	—	350
Real estate funds	—	—	47	47
Total	$ 236	$ 395	$ 47	$ 678
As of December 31, 2014				
Cash equivalents	$ —	$ 24	$ —	$ 24
Debt securities:				
United States government obligations	8	—	—	8
Corporate obligations	—	29	—	29
Municipal obligations	—	4	—	4
Agency, asset and mortgage-backed obligations	—	33	—	33
Equity securities:				
United States companies	149	—	—	149
International equity securities	40	—	—	40
Investment funds[2]	84	319	—	403
Real estate funds	—	—	40	40
Total	$ 281	$ 409	$ 40	$ 730

(1) Refer to Note 13 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds are comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 72% and 28%, respectively, for 2015 and 68% and 32%, respectively, for 2014. Additionally, these funds are invested in United States and international securities of approximately 73% and 27%, respectively, for 2015 and 74% and 26%, respectively, for 2014.

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

	Input Levels for Fair Value Measurements[(1)]			
	Level 1	Level 2	Level 3	Total
As of December 31, 2015				
Cash equivalents	$ 5	$ —	$ —	$ 5
Debt securities:				
United States government obligations	5	—	—	5
Corporate obligations	—	12	—	12
Municipal obligations	—	39	—	39
Agency, asset and mortgage-backed obligations	—	12	—	12
Equity securities:				
United States companies	120	—	—	120
Investment funds[(2)]	56	—	—	56
Total	$ 186	$ 63	$ —	$ 249
As of December 31, 2014				
Cash equivalents	$ 4	$ —	$ —	$ 4
Debt securities:				
United States government obligations	5	—	—	5
Corporate obligations	—	11	—	11
Municipal obligations	—	40	—	40
Agency, asset and mortgage-backed obligations	—	15	—	15
Equity securities:				
United States companies	128	—	—	128
Investment funds[(2)]	56	—	—	56
Total	$ 193	$ 66	$ —	$ 259

(1) Refer to Note 13 for additional discussion regarding the three levels of the fair value hierarchy.

(2) Investment funds are comprised of mutual funds and collective trust funds. These funds consist of equity and debt securities of approximately 68% and 32%, respectively, for 2015 and 69% and 31%, respectively, for 2014. Additionally, these funds are invested in United States and international securities of approximately 32% and 68%, respectively, for 2015 and 31% and 69%, respectively, for 2014.

When available, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value. In the absence of a quoted market price or net asset value of an identical security, the fair value is determined using pricing models or net asset values based on observable market inputs and quoted market prices of securities with similar characteristics. When observable market data is not available, the fair value is determined using unobservable inputs, such as estimated future cash flows, purchase multiples paid in other comparable third-party transactions or other information. The real estate funds determine fair value of their underlying assets using independent appraisals given there is no current liquid market for the underlying assets. The following table reconciles the beginning and ending balances of MidAmerican Energy's pension plan assets measured at fair value using significant Level 3 inputs for the years ended December 31, (in millions):

	Real Estate Funds		
	2015	2014	2013
Beginning balance	$ 40	$ 31	$ 26
Actual return on plan assets still held at period end	7	4	5
Purchases and sales	—	5	—
Ending balance	$ 47	$ 40	$ 31

MidAmerican Energy sponsors a defined contribution plan ("401(k) plan") covering substantially all employees. MidAmerican Energy's matching contributions are based on each participant's level of contribution, and certain participants receive contributions based on eligible pre-tax annual compensation. Contributions cannot exceed the maximum allowable for tax purposes. Certain participants now receive enhanced benefits in the 401(k) plan and no longer accrue benefits in the noncontributory defined benefit pension plans. MidAmerican Energy's contributions to the plan were $20 million, $19 million, and $17 million for the years ended December 31, 2015, 2014 and 2013, respectively.

(11) Asset Retirement Obligations

MidAmerican Energy 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.

MidAmerican Energy 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 generation, transmission, distribution and other assets cannot currently be estimated, and no amounts are recognized on the Financial Statements other than those included in the cost of removal regulatory liability established via approved depreciation rates in accordance with accepted regulatory practices. These accruals totaled $653 million and $642 million as of December 31, 2015 and 2014, respectively.

The following table presents MidAmerican Energy's ARO liabilities by asset type as of December 31, (in millions):

	2015	2014
Quad Cities Station	$ 289	$ 265
Fossil-fueled generating facilities	160	132
Wind-powered generating facilities	82	60
Other	1	3
Total asset retirement obligations	$ 532	$ 460
Quad Cities Station nuclear decommissioning trust funds[1]	$ 429	$ 424

(1) Refer to Note 6 for a discussion of the Quad Cities Station nuclear decommissioning trust funds.

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

	2015	2014
Beginning balance	$ 460	$ 430
Change in estimated costs	36	(2)
Additions	22	11
Retirements	(9)	—
Accretion	23	21
Ending balance	$ 532	$ 460
Reflected as:		
Other current liabilities	$ 44	$ 28
Asset retirement obligations	488	432
	$ 532	$ 460

In December 2014, the United States 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, which was effective in October 2015, resulted in increases to MidAmerican Energy's ARO liabilities due to changes in the expected timing and amount of cash flow for ash pond closures at some of MidAmerican Energy's thermal generating facilities.

(12) Risk Management and Hedging Activities

MidAmerican Energy is exposed to the impact of market fluctuations in commodity prices and interest rates. MidAmerican Energy is principally exposed to electricity, natural gas, coal and fuel oil commodity price risk as it has an obligation to serve retail customer load in its regulated service territory. MidAmerican Energy has also provided nonregulated retail electricity and natural gas services in competitive markets. MidAmerican Energy'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, wholesale electricity that is purchased and sold, and natural gas supply for retail customers. 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. MidAmerican Energy does not engage in a material amount of proprietary trading activities.

MidAmerican Energy 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, MidAmerican Energy uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. MidAmerican Energy 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, MidAmerican Energy may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate its exposure to interest rate risk. MidAmerican Energy 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 MidAmerican Energy's accounting policies related to derivatives. Refer to Notes 2 and 13 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 MidAmerican Energy's derivative contracts, on a gross basis, and reconciles those amounts to the amounts presented on a net basis on the Balance Sheets (in millions):

	Current Assets - Other	Other Assets - Other	Current Liabilities - Other	Other Liabilities - Other	Total
As of December 31, 2015					
Not designated as hedging contracts[(1)]:					
Commodity assets	$ 12	$ 4	$ 5	$ 2	$ 23
Commodity liabilities	(3)	—	(36)	(10)	(49)
Total	9	4	(31)	(8)	(26)
Designated as hedging contracts:					
Commodity assets	—	—	1	2	3
Commodity liabilities	—	—	(32)	(17)	(49)
Total	—	—	(31)	(15)	(46)
Total derivatives	9	4	(62)	(23)	(72)
Cash collateral receivable	—	—	22	6	28
Total derivatives - net basis	$ 9	$ 4	$ (40)	$ (17)	$ (44)
As of December 31, 2014					
Not designated as hedging contracts[(1)]:					
Commodity assets	$ 14	$ 3	$ 19	$ 1	$ 37
Commodity liabilities	—	—	(69)	(4)	(73)
Total	14	3	(50)	(3)	(36)
Designated as hedging contracts:					
Commodity assets	—	—	4	2	6
Commodity liabilities	—	—	(27)	(17)	(44)
Total	—	—	(23)	(15)	(38)
Total derivatives	14	3	(73)	(18)	(74)
Cash collateral receivable	—	—	42	5	47
Total derivatives - net basis	$ 14	$ 3	$ (31)	$ (13)	$ (27)

(1) MidAmerican Energy's commodity derivatives not designated as hedging contracts are generally included in regulated rates. Accordingly, as of December 31, 2015 and 2014, a net regulatory asset of $20 million and $38 million, respectively, was recorded related to the net derivative liability of $26 million and $36 million, respectively.

Not Designated as Hedging Contracts

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

	2015	2014	2013
Beginning balance	$ 38	$ 10	$ 45
Changes in fair value recognized in net regulatory assets	40	61	5
Net losses reclassified to operating revenue	(42)	(28)	(1)
Net losses reclassified to cost of fuel, energy and capacity	(1)	(1)	(1)
Net losses reclassified to cost of gas sold	(15)	(4)	(38)
Ending balance	$ 20	$ 38	$ 10

The following table summarizes the pre-tax unrealized gains (losses) included on the Statements of Operations associated with MidAmerican Energy's derivative contracts not designated as hedging contracts and not recorded as a net regulatory asset or liability for the years ended December 31 (in millions):

	2015	2014	2013
Nonregulated operating revenue	$ 15	$ 6	$ —
Regulated cost of fuel, energy and capacity	2	—	—
Nonregulated cost of sales	(21)	9	(2)
Total	$ (4)	$ 15	$ (2)

Designated as Hedging Contracts

MidAmerican Energy uses derivative contracts accounted for as cash flow hedges to hedge electricity and natural gas commodity prices for delivery to nonregulated customers.

The following table reconciles the beginning and ending balances of MidAmerican Energy's accumulated other comprehensive loss (pre-tax) and summarizes pre-tax gains and losses on derivative contracts designated and qualifying as cash flow hedges recognized in OCI, as well as amounts reclassified to earnings, for the years ended December 31 (in millions):

	2015	2014	2013
Beginning balance	$ 34	$ 11	$ 32
Changes in fair value recognized in OCI	58	(3)	(11)
Net (losses) gains reclassified to nonregulated cost of sales	(47)	26	(10)
Ending balance	$ 45	$ 34	$ 11

Realized gains and losses on hedges and hedge ineffectiveness are recognized in income as nonregulated operating revenue or nonregulated cost of sales depending upon the nature of the item being hedged. For the years ended December 31, 2015, 2014 and 2013, hedge ineffectiveness was a pre-tax gain of $1 million, a pre-tax loss of $2 million and $- million, respectively. As of December 31, 2015, MidAmerican Energy had cash flow hedges with expiration dates extending through December 2020, and $32 million of pre-tax net unrealized losses are forecasted to be reclassified from AOCI into earnings over the next twelve months as contracts settle.

Derivative Contract Volumes

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

	Unit of Measure	2015	2014
Electricity purchases	Megawatt hours	15	14
Natural gas purchases	Decatherms	17	19

Credit Risk

MidAmerican Energy 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. Additionally, MidAmerican Energy participates in the regional transmission organization ("RTO") markets and has indirect credit exposure related to other participants, although RTO credit policies are designed to limit exposure to credit losses from individual participants. Credit risk may be concentrated to the extent MidAmerican Energy's counterparties have similar economic, industry or other characteristics and due to direct or indirect relationships among the counterparties. Before entering into a transaction, MidAmerican Energy 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, MidAmerican Energy 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, MidAmerican Energy 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 MidAmerican Energy's collateral requirements on its 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," or in some cases terminate the contract, in the event of a material adverse change in MidAmerican Energy's creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2015, MidAmerican Energy's credit ratings from the three recognized credit rating agencies were investment grade.

The aggregate fair value of MidAmerican Energy's derivative contracts in liability positions with specific credit-risk-related contingent features totaled $66 million and $52 million as of December 31, 2015 and 2014, respectively, for which MidAmerican Energy had posted collateral of $- million at each date. If all credit-risk-related contingent features for derivative contracts in liability positions had been triggered as of December 31, 2015 and 2014, MidAmerican Energy would have been required to post $55 million and $36 million, respectively, of additional collateral. MidAmerican Energy's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation, or other factors.

(13) Fair Value Measurements

The carrying value of MidAmerican Energy'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. MidAmerican Energy has various financial assets and liabilities that are measured at fair value on the 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 MidAmerican Energy 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 MidAmerican Energy's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. MidAmerican Energy develops these inputs based on the best information available, including its own data.

The following table presents MidAmerican Energy's assets and liabilities recognized on the 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, 2015:					
Assets:					
Commodity derivatives	$ —	$ 8	$ 18	$ (13)	$ 13
Money market mutual funds[2]	56	—	—	—	56
Debt securities:					
United States government obligations	133	—	—	—	133
International government obligations	—	2	—	—	2
Corporate obligations	—	39	—	—	39
Municipal obligations	—	1	—	—	1
Agency, asset and mortgage-backed obligations	—	3	—	—	3
Auction rate securities	—	—	26	—	26
Equity securities:					
United States companies	239	—	—	—	239
International companies	6	—	—	—	6
Investment funds	4	—	—	—	4
	$ 438	$ 53	$ 44	$ (13)	$ 522
Liabilities - commodity derivatives	$ (13)	$ (61)	$ (24)	$ 41	$ (57)
As of December 31, 2014:					
Assets:					
Commodity derivatives	$ 1	$ 18	$ 24	$ (26)	$ 17
Money market mutual funds[2]	1	—	—	—	1
Debt securities:					
United States government obligations	136	—	—	—	136
International government obligations	—	1	—	—	1
Corporate obligations	—	39	—	—	39
Municipal obligations	—	2	—	—	2
Agency, asset and mortgage-backed obligations	—	2	—	—	2
Auction rate securities	—	—	26	—	26
Equity securities:					
United States companies	238	—	—	—	238
International companies	5	—	—	—	5
	$ 381	$ 62	$ 50	$ (26)	$ 467
Liabilities - commodity derivatives	$ (18)	$ (87)	$ (12)	$ 73	$ (44)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $28 million and $47 million as of December 31, 2015 and 2014, respectively.

(2) Amounts are included in cash and cash equivalents and investments and restricted cash and investments on the Balance Sheets. The fair value of these money market mutual funds approximates cost.

Derivative contracts are recorded on the 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 MidAmerican Energy transacts. When quoted prices for identical contracts are not available, MidAmerican Energy uses forward price curves. Forward price curves represent MidAmerican Energy's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. MidAmerican Energy 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 MidAmerican Energy. Market price quotations are generally readily obtainable for the applicable term of MidAmerican Energy's outstanding derivative contracts; therefore, MidAmerican Energy's forward price curves reflect observable market quotes. Market price quotations for certain electricity and natural gas trading hubs are not as readily obtainable due to the length of the contract. Given that limited market data exists for these contracts, as well as for those contracts that are not actively traded, MidAmerican Energy 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, related volatility, counterparty creditworthiness and duration of contracts. Refer to Note 12 for further discussion regarding MidAmerican Energy's risk management and hedging activities.

MidAmerican Energy's investments in money market mutual funds and debt and equity securities are stated at fair value and are accounted for as available-for-sale securities. When available, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value. In the absence of a quoted market price or net asset value of an identical security, the fair value is determined using pricing models or net asset values based on observable market inputs and quoted market prices of securities with similar characteristics. The fair value of MidAmerican Energy's investments in auction rate securities, where there is no current liquid market, is determined using pricing models based on available observable market data and MidAmerican Energy's judgment about the assumptions, including liquidity and nonperformance risks, which market participants would use when pricing the asset.

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

	Commodity Derivatives			Auction Rate Securities		
	2015	2014	2013	2015	2014	2013
Beginning balance	$ 12	$ (3)	$ —	$ 26	$ 23	$ 21
Changes included in earnings(1)	11	12	3	—	—	—
Changes in fair value recognized in OCI	(7)	—	(2)	—	3	2
Changes in fair value recognized in net regulatory assets	(25)	6	—	—	—	—
Purchases	1	1	—	—	—	—
Settlements	2	(4)	(4)	—	—	—
Ending balance	$ (6)	$ 12	$ (3)	$ 26	$ 26	$ 23

(1) Changes included in earnings are reported as nonregulated operating revenue on the Statements of Operations. Net unrealized (losses) gains included in earnings for the years ended December 31, 2015, 2014 and 2013, related to commodity derivatives held at December 31, 2015, 2014 and 2013, totaled $8 million, $16 million and $(5) million, respectively.

MidAmerican Energy's long-term debt is carried at cost on the Financial Statements. The fair value of MidAmerican Energy'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 MidAmerican Energy'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 MidAmerican Energy's long-term debt as of December 31, (in millions):

	2015		2014	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 4,271	$ 4,636	$ 4,056	$ 4,581

(14) Commitments and Contingencies

Commitments

MidAmerican Energy had the following firm commitments that are not reflected on the Balance Sheet. Minimum payments as of December 31, 2015, are as follows (in millions):

	2016	2017	2018	2019	2020	2021 and Thereafter	Total
Contract type:							
Coal and natural gas for generation	$ 173	$ 113	$ 72	$ 29	$ —	$ —	$ 387
Electric capacity and transmission	30	30	11	10	10	58	149
Natural gas contracts for gas operations	131	69	31	11	10	30	282
Construction commitments	535	10	—	—	—	—	545
Easements and operating leases	17	17	17	16	15	516	598
Maintenance and services contracts	47	59	71	73	73	265	588
	$ 933	$ 298	$ 202	$ 139	$ 108	$ 869	$ 2,549

Coal, Natural Gas, Electric Capacity and Transmission Commitments

MidAmerican Energy has coal supply and related transportation and lime contracts for its coal-fueled generating facilities. MidAmerican Energy expects to supplement the coal contracts with additional contracts and spot market purchases to fulfill its future coal supply needs. Additionally, MidAmerican Energy has a natural gas transportation contract for a natural gas-fueled generating facility. The contracts have minimum payment commitments ranging through 2019.

MidAmerican Energy has various natural gas supply and transportation contracts for its regulated and nonregulated gas operations that have minimum payment commitments ranging through 2025.

MidAmerican Energy has contracts to purchase electric capacity to meet its electric system energy requirements that have minimum payment commitments ranging through 2028. MidAmerican Energy also has contracts for the right to transmit electricity over other entities' transmission lines with minimum payment commitments ranging through 2020.

Construction Commitments

MidAmerican Energy's firm construction commitments reflected in the table above consist primarily of contracts for the construction of wind-powered generating facilities in 2016 and the construction in 2016 through 2017 of four Multi-Value Projects approved by the Midcontinent Independent System Operator, Inc. for high voltage transmission lines in Iowa and Illinois.

Easements and Operating Leases

MidAmerican Energy has non-cancelable easements with minimum payment commitments ranging through 2061 for land in Iowa on which its wind-powered generating facilities are located. MidAmerican Energy also has non-cancelable operating leases with minimum payment commitments ranging through 2020 primarily for office and other building space, rail cars and computer equipment. These leases generally require MidAmerican Energy 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. Rent expense on non-cancelable operating leases totaled $4 million, $4 million and $6 million for 2015, 2014 and 2013, respectively.

Maintenance and Services Contracts

MidAmerican Energy has non-cancelable maintenance and services contracts related to various generating facilities with minimum payment commitments ranging through 2029.

Environmental Laws and Regulations

MidAmerican Energy is subject to federal, state and local laws and regulations regarding air and water quality, 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 its current and future operations. MidAmerican Energy believes it is in material compliance with all applicable laws and regulations.

Legal Matters

MidAmerican Energy is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. MidAmerican Energy does not believe that such normal and routine litigation will have a material impact on its financial results.

(15) Components of Accumulated Other Comprehensive Loss, Net

The following table shows the change in accumulated other comprehensive loss by each component of other comprehensive income, net of applicable income taxes, for the years ended December 31, 2015 and 2014 (in millions):

	Unrealized Losses on Available-For-Sale Securities	Unrealized Losses on Cash Flow Hedges	Accumulated Other Comprehensive Loss, Net
Balance, December 31, 2013	$ (4)	$ (7)	$ (11)
Other comprehensive income (loss)	1	(13)	(12)
Balance, December 31, 2014	$ (3)	$ (20)	$ (23)
Other comprehensive income (loss)	—	(7)	(7)
Balance, December 31, 2015	$ (3)	$ (27)	$ (30)

For information regarding cash flow hedge reclassifications from AOCI to net income in their entirety for the years ended December 31, 2015, 2014 and 2013, refer to Note 12.

(16) Preferred Securities

In April 2013, MidAmerican Energy redeemed and canceled all outstanding shares of each series of its preferred securities at the stated redemption prices, which in aggregate totaled $28 million including accrued dividends.

(17) Other Income and (Expense) - Other, Net

Other, net, as shown on the Statements of Operations, includes the following other income (expense) items for the years ended December 31 (in millions):

	2015	2014	2013
Corporate-owned life insurance income	$ 4	$ 8	$ 15
Gains on sales of assets and other investments	—	—	1
Other, net	1	2	—
Total	$ 5	$ 10	$ 16

(18) Supplemental Cash Flow Disclosures

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

	2015	2014	2013
Supplemental cash flow information:			
Interest paid, net of amounts capitalized	$ 154	$ 144	$ 109
Income taxes received, net	$ 629	$ 149	$ 36
Supplemental disclosure of non-cash investing transactions:			
Accounts payable related to utility plant additions	$ 249	$ 128	$ 117

(19) Related Party Transactions

The companies identified as affiliates of MidAmerican Energy are Berkshire Hathaway and its subsidiaries, including BHE and its subsidiaries. The basis for the following transactions is provided for in service agreements between MidAmerican Energy and the affiliates.

MidAmerican Energy is reimbursed for charges incurred on behalf of its affiliates. The majority of these reimbursed expenses are for general costs, such as insurance and building rent, and for employee wages, benefits and costs related to corporate functions such as information technology, human resources, treasury, legal and accounting. The amount of such reimbursements was $46 million, $58 million and $38 million for 2015, 2014 and 2013, respectively.

MidAmerican Energy reimbursed BHE in the amount of $7 million, $8 million and $10 million in 2015, 2014 and 2013, respectively, for its share of corporate expenses.

MidAmerican Energy purchases natural gas transportation and storage capacity services from Northern Natural Gas Company, a wholly owned subsidiary of BHE, and coal transportation services from BNSF Railway Company, a wholly-owned subsidiary of Berkshire Hathaway, in the normal course of business at either tariffed or market prices. These purchases totaled $165 million, $144 million and $155 million in 2015, 2014 and 2013, respectively.

MidAmerican Energy had accounts receivable from affiliates of $5 million and $12 million as of December 31, 2015 and 2014, respectively, that are included in receivables on the Balance Sheets. MidAmerican Energy also had accounts payable to affiliates of $13 million and $12 million as of December 31, 2015 and 2014, respectively, that are included in accounts payable on the Balance Sheets.

MidAmerican Energy is party to a tax-sharing agreement and is part of the Berkshire Hathaway United States federal income tax return. As of December 31, 2015 and 2014, MidAmerican Energy had current federal and state income taxes receivable from BHE of $102 million and $299 million, respectively. MidAmerican Energy received net cash receipts for federal and state income taxes from BHE totaling $629 million, $149 million and $36 million for the years ended December 31, 2015, 2014 and 2013, respectively.

MidAmerican Energy recognizes the full amount of the funded status for its pension and postretirement plans, and amounts attributable to MidAmerican Energy's affiliates that have not previously been recognized through income are recognized as an intercompany balance with such affiliates. MidAmerican Energy adjusts these balances when changes to the funded status of the respective plans are recognized and does not intend to settle the balances currently. Amounts receivable from affiliates attributable to the funded status of employee benefit plans totaled $10 million and $13 million as of December 31, 2015 and 2014, respectively, and similar amounts payable to affiliates totaled $29 million and $30 million as of December 31, 2015 and 2014, respectively. See Note 10 for further information pertaining to pension and postretirement accounting.

(20) Segment Information

MidAmerican Energy has identified three reportable operating segments: regulated electric, regulated gas and nonregulated energy. The regulated electric segment derives most of its revenue from regulated retail sales of electricity to residential, commercial, and industrial customers and from wholesale sales. The regulated gas segment derives most of its revenue from regulated retail sales of natural gas to residential, commercial, and industrial customers and also obtains revenue by transporting gas owned by others through its distribution system. Pricing for regulated electric and regulated gas sales are established separately by regulatory agencies; therefore, management also reviews each segment separately to make decisions regarding allocation of resources and in evaluating performance. The nonregulated energy segment derives most of its revenue from nonregulated retail electric and gas activities. Common operating costs, interest income, interest expense and income tax expense are allocated to each segment based on certain factors, which primarily relate to the nature of the cost. Refer to Note 9 for a discussion of items affecting income tax (benefit) expense for the regulated electric and gas operating segments. The following tables provide information on a reportable segment basis (in millions):

	Years Ended December 31,		
	2015	2014	2013
Operating revenue:			
Regulated electric	$ 1,837	$ 1,817	$ 1,762
Regulated gas	661	996	824
Nonregulated energy	909	927	817
Total operating revenue	$ 3,407	$ 3,740	$ 3,403
Depreciation and amortization:			
Regulated electric	$ 366	$ 312	$ 366
Regulated gas	41	39	37
Total depreciation and amortization	$ 407	$ 351	$ 403
Operating income:			
Regulated electric	$ 385	$ 319	$ 255
Regulated gas	64	75	74
Nonregulated energy	22	28	27
Total operating income	$ 471	$ 422	$ 356
Interest expense:			
Regulated electric	$ 166	$ 157	$ 136
Regulated gas	17	17	15
Total interest expense	$ 183	$ 174	$ 151
Income tax (benefit) expense:			
Regulated electric	$ (163)	$ (138)	$ (136)
Regulated gas	16	22	23
Nonregulated energy	6	12	10
Total income tax (benefit) expense	$ (141)	$ (104)	$ (103)
Earnings on common stock:			
Regulated electric	$ 413	$ 361	$ 292
Regulated gas	33	40	41
Nonregulated energy	16	16	16
Total earnings on common stock	$ 462	$ 417	$ 349

	Years Ended December 31,		
	2015	2014	2013
Utility construction expenditures:			
Regulated electric	$ 1,365	$ 1,429	$ 945
Regulated gas	81	97	81
Total utility construction expenditures	$ 1,446	$ 1,526	$ 1,026

	As of December 31,		
	2015	2014	2013
Total assets:			
Regulated electric	$ 12,970	$ 11,850	$ 10,521
Regulated gas	1,251	1,217	1,196
Nonregulated energy	164	167	131
Total assets	$ 14,385	$ 13,234	$ 11,848

(21) Transfer of Nonregulated Energy Operations

In the second quarter of 2015, MidAmerican Energy filed with the IUB and ICC for approval to transfer the assets and liabilities of its unregulated retail services business in a common control transaction to a subsidiary of BHE. MidAmerican Energy's request was approved by the IUB in July 2015 and by the ICC in October 2015. The transfer, which was effective January 1, 2016, was made at MidAmerican Energy's carrying value of the assets and liabilities as of December 31, 2015, and was recorded by MidAmerican Energy as a dividend. As of and for the year ended December 31, 2015, the financial results of the unregulated retail services business consisted of net assets of $88 million, operating revenue of $905 million, operating income of $22 million, net income of $16 million and cash flows from operating activities of $30 million.

(22) Unaudited Quarterly Operating Results

	2015			
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	(In millions)			
Operating revenue	$ 946	$ 793	$ 920	$ 748
Operating income	106	122	210	33
Net income	94	131	234	3

	2014			
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	(In millions)			
Operating revenue	$ 1,225	$ 769	$ 862	$ 884
Operating income	153	51	160	58
Net income	157	32	170	58

Quarterly data reflect seasonal variations common to a Midwest utility.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Managers and Member of
MidAmerican Funding, LLC
Des Moines, Iowa

We have audited the accompanying consolidated balance sheets of MidAmerican Funding, LLC and subsidiaries ("MidAmerican Funding") as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2015. Our audits also included MidAmerican Funding's financial statement schedules listed in the Index at Item 15(a)(2). These financial statements and financial statement schedules are the responsibility of MidAmerican Funding's management. Our responsibility is to express an opinion on the financial statements and financial statement schedules 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. MidAmerican Funding 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 MidAmerican Funding'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 MidAmerican Funding, LLC and subsidiaries as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly in all material respects the information set forth therein.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 26, 2016

MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2015	**2014**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 103	$ 30
Receivables, net	346	437
Income taxes receivable	104	303
Inventories	238	185
Other current assets	58	86
Total current assets	849	1,041
Property, plant and equipment, net	11,737	10,535
Goodwill	1,270	1,270
Regulatory assets	1,044	908
Investments and restricted cash and investments	636	627
Other assets	138	141
Total assets	$ 15,674	$ 14,522

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

MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (continued)
(Amounts in millions)

	As of December 31,	
	2015	**2014**
LIABILITIES AND MEMBER'S EQUITY		
Current liabilities:		
Accounts payable	$ 427	$ 392
Accrued interest	53	48
Accrued property, income and other taxes	125	128
Note payable to affiliate	139	136
Short-term debt	—	50
Current portion of long-term debt	34	426
Other current liabilities	166	131
Total current liabilities	944	1,311
Long-term debt	4,563	3,934
Deferred income taxes	3,056	2,656
Regulatory liabilities	831	837
Asset retirement obligations	488	432
Other long-term liabilities	267	279
Total liabilities	10,149	9,449
Commitments and contingencies (Note 14)		
Member's equity:		
Paid-in capital	1,679	1,679
Retained earnings	3,876	3,417
Accumulated other comprehensive loss, net	(30)	(23)
Total member's equity	5,525	5,073
Total liabilities and member's equity	$ 15,674	$ 14,522

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

MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2015	2014	2013
Operating revenue:			
Regulated electric	$ 1,837	$ 1,817	$ 1,762
Regulated gas	661	996	824
Nonregulated	922	949	827
Total operating revenue	3,420	3,762	3,413
Operating costs and expenses:			
Regulated:			
Cost of fuel, energy and capacity	433	532	517
Cost of gas sold	397	720	558
Operations and maintenance	687	699	659
Depreciation and amortization	407	351	403
Property and other taxes	124	123	119
Nonregulated:			
Cost of sales	864	881	764
Other	35	33	36
Total operating costs and expenses	2,947	3,339	3,056
Operating income	473	423	357
Other income and (expense):			
Interest expense	(206)	(197)	(174)
Allowance for borrowed funds	8	16	7
Allowance for equity funds	20	39	19
Other, net	19	18	22
Total other income and (expense)	(159)	(124)	(126)
Income before income tax benefit	314	299	231
Income tax benefit	(144)	(110)	(110)
Net income	458	409	341
Net income attributable to noncontrolling interests	—	—	1
Net income attributable to MidAmerican Funding	$ 458	$ 409	$ 340

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

MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Amounts in millions)

	Years Ended December 31,		
	2015	2014	2013
Net income	$ 458	$ 409	$ 341
Other comprehensive (loss) income, net of tax:			
Unrealized gains on available-for-sale securities, net of tax of $-, $1 and $1	—	1	1
Unrealized (losses) gains on cash flow hedges, net of tax of $(4), $(10) and $9	(7)	(13)	12
Total other comprehensive (loss) income, net of tax	(7)	(12)	13
Comprehensive income	451	397	354
Comprehensive income attributable to noncontrolling interests	—	—	1
Comprehensive income attributable to MidAmerican Funding	$ 451	$ 397	$ 353

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

MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(Amounts in millions)

	MidAmerican Funding Member's Equity				
	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss, Net	Noncontrolling Interests	Total Equity
Balance, December 31, 2012	$ 1,679	$ 2,669	$ (24)	$ 27	$ 4,351
Net income	—	340	—	1	341
Other comprehensive income	—	—	13	—	13
Redemption of preferred securities of subsidiary	—	—	—	(28)	(28)
Balance, December 31, 2013	1,679	3,009	(11)	—	4,677
Net income	—	409	—	—	409
Other comprehensive loss	—	—	(12)	—	(12)
Other equity transactions	—	(1)	—	—	(1)
Balance, December 31, 2014	1,679	3,417	(23)	—	5,073
Net income	—	458	—	—	458
Other comprehensive loss	—	—	(7)	—	(7)
Other equity transactions	—	1	—	—	1
Balance, December 31, 2015	$ 1,679	$ 3,876	$ (30)	$ —	$ 5,525

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

MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31,		
	2015	2014	2013
Cash flows from operating activities:			
Net income	$ 458	$ 409	$ 341
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	407	351	403
Deferred income taxes and amortization of investment tax credits	276	298	102
Changes in other assets and liabilities	49	47	57
Other, net	(69)	(49)	(29)
Changes in other operating assets and liabilities:			
Receivables, net	93	(2)	(60)
Inventories	(53)	44	13
Derivative collateral, net	33	(53)	5
Contributions to pension and other postretirement benefit plans, net	(8)	(2)	8
Accounts payable	(76)	30	23
Accrued property, income and other taxes, net	213	(253)	(164)
Other current assets and liabilities	12	—	22
Net cash flows from operating activities	1,335	820	721
Cash flows from investing activities:			
Utility construction expenditures	(1,446)	(1,526)	(1,026)
Purchases of available-for-sale securities	(142)	(88)	(114)
Proceeds from sales of available-for-sale securities	135	80	102
Proceeds from sales of other investments	13	10	16
Other, net	2	5	10
Net cash flows from investing activities	(1,438)	(1,519)	(1,012)
Cash flows from financing activities:			
Proceeds from long-term debt	649	840	940
Repayments of long-term debt	(426)	(356)	(670)
Redemption of preferred securities of subsidiary	—	—	(28)
Net change in note payable to affiliate	3	1	(111)
Net (repayments of) proceeds from short-term debt	(50)	50	—
Net cash flows from financing activities	176	535	131
Net change in cash and cash equivalents	73	(164)	(160)
Cash and cash equivalents at beginning of year	30	194	354
Cash and cash equivalents at end of year	$ 103	$ 30	$ 194

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

(1) Company Organization

MidAmerican Funding, LLC ("MidAmerican Funding") is an Iowa limited liability company with Berkshire Hathaway Energy Company ("BHE") as its sole member. BHE is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway"). MidAmerican Funding's direct wholly owned subsidiary is MHC Inc. ("MHC"), which constitutes substantially all of MidAmerican Funding's assets, liabilities and business activities except those related to MidAmerican Funding's long-term debt securities. MHC conducts no business other than the ownership of its subsidiaries and related corporate services. MHC's principal subsidiary is MidAmerican Energy Company ("MidAmerican Energy"), a public utility with electric and natural gas operations. Direct, wholly owned nonregulated subsidiaries of MHC are Midwest Capital Group, Inc. ("Midwest Capital Group") and MEC Construction Services Co.

(2) Summary of Significant Accounting Policies

In addition to the following significant accounting policies, refer to Note 2 of MidAmerican Energy's Notes to Financial Statements for significant accounting policies of MidAmerican Funding.

Basis of Consolidation and Presentation

The Consolidated Financial Statements include the accounts of MidAmerican Funding and its subsidiaries in which it held a controlling financial interest as of the financial statement date. Intercompany accounts and transactions have been eliminated, other than those between rate-regulated operations.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of identifiable net assets acquired when MidAmerican Funding purchased MHC. MidAmerican Funding evaluates goodwill for impairment at least annually and completed its annual review as of October 31. When evaluating goodwill for impairment, MidAmerican Funding estimates the fair value of the reporting unit. If the carrying amount of a reporting unit, including goodwill, exceeds the estimated fair value, then the identifiable assets, including identifiable intangible assets, and liabilities of the reporting unit are estimated at fair value as of the current testing date. The excess of the estimated fair value of the reporting unit over the current estimated fair value of net assets establishes the implied value of goodwill. The excess of the recorded goodwill over the implied goodwill value is charged to earnings as an impairment loss. Significant judgment is required in estimating the fair value of the reporting unit and performing goodwill impairment tests. MidAmerican Funding uses a variety of methods to estimate a reporting unit's fair value, principally discounted projected future net cash flows. Key assumptions used include, but are not limited to, the use of estimated future cash flows; multiples of earnings; and an appropriate discount rate. In estimating future cash flows, MidAmerican Funding incorporates current market information, as well as historical factors. As such, the determination of fair value incorporates significant unobservable inputs. During 2015, 2014 and 2013, MidAmerican Funding did not record any goodwill impairments.

(3) Property, Plant and Equipment, Net

Refer to Note 3 of MidAmerican Energy's Notes to Financial Statements. In addition to MidAmerican Energy's property, plant and equipment, net, MidAmerican Funding had nonregulated property gross of $22 million as of December 31, 2015 and 2014 and related accumulated depreciation and amortization of $8 million as of December 31, 2015 and 2014, which consisted primarily of a corporate aircraft owned by MHC.

(4) Jointly Owned Utility Facilities

Refer to Note 4 of MidAmerican Energy's Notes to Financial Statements.

(5) Regulatory Matters

Refer to Note 5 of MidAmerican Energy's Notes to Financial Statements.

(6) Investments and Restricted Cash and Investments

Refer to Note 6 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K. In addition to MidAmerican Energy's investments and restricted cash and investments, MHC had corporate-owned life insurance policies in a Rabbi trust owned by MHC with a total cash surrender value of $2 million as of December 31, 2015 and 2014.

(7) Short-Term Debt and Credit Facilities

Refer to Note 7 of MidAmerican Energy's Notes to Financial Statements. In addition to MidAmerican Energy's credit facilities, MHC has a $4 million unsecured credit facility, which expires in June 2016 and has a variable interest rate based on LIBOR plus a spread. As of December 31, 2015 and 2014, there were no borrowings outstanding under this credit facility. As of December 31, 2015, MHC was in compliance with the covenants of its credit facility.

(8) Long-Term Debt

Refer to Note 8 of MidAmerican Energy's Notes to Financial Statements for detail and a discussion of its long-term debt. In addition to MidAmerican Energy's annual repayments of long-term debt, MidAmerican Funding has $325 million of long-term debt due in 2029, with a carrying value of $326 million as of December 31, 2015 and 2014.

MidAmerican Funding parent company long-term debt is secured by a pledge of the common stock of MHC. See Item 15(c) for the Consolidated Financial Statements of MHC Inc. and subsidiaries. The bonds are the direct senior secured obligations of MidAmerican Funding and effectively rank junior to all indebtedness and other liabilities of the direct and indirect subsidiaries of MidAmerican Funding, to the extent of the assets of these subsidiaries. MidAmerican Funding may redeem the bonds in whole or in part at any time at a redemption price equal to the sum of any accrued and unpaid interest to the date of redemption and the greater of (1) 100% of the principal amount of the bonds or (2) the sum of the present values of the remaining scheduled payments of principal and interest on the bonds, discounted to the date of redemption on a semiannual basis at the treasury yield plus 25 basis points.

Subsidiaries of MidAmerican Funding must make payments on their own indebtedness before making distributions to MidAmerican Funding. Refer to Note 8 of MidAmerican Energy's Notes to Financial Statements for a discussion of utility regulatory restrictions affecting distributions from MidAmerican Energy. As a result of the utility regulatory restrictions agreed to by MidAmerican Energy in March 1999, MidAmerican Funding had restricted net assets of $3.1 billion as of December 31, 2015.

As of December 31, 2015, MidAmerican Funding was in compliance with all of its applicable long-term debt covenants.

Each of MidAmerican Funding's direct or indirect subsidiaries is organized as a legal entity separate and apart from MidAmerican Funding and its other subsidiaries. It should not be assumed that any asset of any subsidiary of MidAmerican Funding will be available to satisfy the obligations of MidAmerican Funding or any of its other subsidiaries; provided, however, that unrestricted cash or other assets which are available for distribution may, subject to applicable law and the terms of financing arrangements of such parties, be advanced, loaned, paid as dividends or otherwise distributed or contributed to MidAmerican Funding, one of its subsidiaries or affiliates thereof.

(9) Income Taxes

MidAmerican Funding's income tax benefit consists of the following for the years ended December 31 (in millions):

	2015	2014	2013
Current:			
Federal	$ (408)	$ (404)	$ (200)
State	(12)	(4)	(12)
	(420)	(408)	(212)
Deferred:			
Federal	282	297	100
State	(5)	2	3
	277	299	103
Investment tax credits	(1)	(1)	(1)
Total	$ (144)	$ (110)	$ (110)

A reconciliation of the federal statutory income tax rate MidAmerican Funding's the effective income tax rate applicable to income before income tax benefit is as follows for the years ended December 31:

	2015	2014	2013
Federal statutory income tax rate	35 %	35 %	35 %
Income tax credits	(67)	(61)	(75)
State income tax, net of federal income tax benefit	(3)	(1)	(3)
Effects of ratemaking	(12)	(9)	(3)
Other, net	1	(1)	(2)
Effective income tax rate	(46)%	(37)%	(48)%

Income tax credits relate primarily to production tax credits earned by MidAmerican Energy's wind-powered generating facilities. Federal renewable electricity production tax credits are earned as energy from qualifying wind-powered generating facilities is produced and sold and are based on a per-kilowatt hour rate pursuant to the applicable federal income tax law. Wind-powered generating facilities are eligible for the credits for 10 years from the date the qualifying generating facilities are placed in service.

MidAmerican Funding's net deferred income tax liability consists of the following as of December 31 (in millions):

	2015	2014
Deferred income tax assets:		
Regulatory liabilities	$ 327	$ 332
Employee benefits	66	68
Derivative contracts	29	30
Asset retirement obligations	214	185
Other	68	70
Total deferred income tax assets	704	685
Deferred income tax liabilities:		
Depreciable property	(3,326)	(2,950)
Regulatory assets	(418)	(366)
Other	(16)	(25)
Total deferred income tax liabilities	(3,760)	(3,341)
Net deferred income tax liability	$ (3,056)	$ (2,656)

As of December 31, 2015, MidAmerican Funding has available $23 million of state carryforwards, principally related to $488 million of net operating losses, that expire at various intervals between 2016 and 2034.

The United States Internal Revenue Service has closed its examination of BHE's income tax returns through December 2009, including components related to MidAmerican Funding. In addition, state jurisdictions have closed their examinations of MidAmerican Funding's income tax returns through at least February 9, 2006, including Iowa and Illinois, which are closed through December 31, 2012, and December 31, 2008, respectively.

A reconciliation of the beginning and ending balances of MidAmerican Funding's net unrecognized tax benefits is as follows for the years ended December 31 (in millions):

	2015	2014
Beginning balance	$ 26	$ 29
Additions based on tax positions related to the current year	4	6
Additions for tax positions of prior years	46	38
Reductions based on tax positions related to the current year	(6)	(4)
Reductions for tax positions of prior years	(46)	(40)
Statute of limitations	(5)	(3)
Settlements	(6)	—
Interest and penalties	(3)	—
Ending balance	$ 10	$ 26

As of December 31, 2015, MidAmerican Funding had unrecognized tax benefits totaling $27 million that, if recognized, would have an impact on the effective tax rate. The remaining unrecognized tax benefits relate 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 MidAmerican Funding's effective income tax rate.

(10) Employee Benefit Plans

Refer to Note 10 of MidAmerican Energy's Notes to Financial Statements for additional information regarding MidAmerican Funding's pension, supplemental retirement and postretirement benefit plans.

Pension and postretirement costs allocated by MidAmerican Funding to its parent and other affiliates in each of the years ended December 31, were as follows (in millions):

	2015	2014	2013
Pension costs	$ 4	$ 4	$ 6
Other postretirement costs	(2)	(2)	(2)

(11) Asset Retirement Obligations

Refer to Note 11 of MidAmerican Energy's Notes to Financial Statements.

(12) Risk Management and Hedging Activities

Refer to Note 12 of MidAmerican Energy's Notes to Financial Statements.

(13) Fair Value Measurements

Refer to Note 13 of MidAmerican Energy's Notes to Financial Statements.

MidAmerican Funding's long-term debt is carried at cost on the Consolidated Financial Statements. The fair value of MidAmerican Funding'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 MidAmerican Funding'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 MidAmerican Funding's long-term debt as of December 31 (in millions):

	2015		2014	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 4,597	$ 5,051	$ 4,381	$ 5,012

(14) Commitments and Contingencies

Refer to Note 14 of MidAmerican Energy's Notes to Financial Statements.

Legal Matters

MidAmerican Funding is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. MidAmerican Funding does not believe that such normal and routine litigation will have a material impact on its consolidated financial results.

(15) Components of Accumulated Other Comprehensive Loss, Net

Refer to Note 15 of MidAmerican Energy's Notes to Financial Statements.

(16) Noncontrolling Interests

Refer to Note 16 of MidAmerican Energy's Notes to Financial Statements for a discussion of MidAmerican Energy's preferred securities, which were MidAmerican Funding's noncontrolling interest at the time of their redemption.

(17) Other Income and (Expense) - Other, Net

Other, net, as shown on the Consolidated Statements of Operations, includes the following other income (expense) items for the years ended December 31 (in millions):

	2015	2014	2013
Corporate-owned life insurance income	$ 4	$ 8	$ 15
Gains on sales of assets and other investments	13	—	1
Leverage leases	1	5	2
Other, net	1	5	4
Total	$ 19	$ 18	$ 22

MidAmerican Funding recognized a $13 million pre-tax gain on the sale of an investment in a generating facility lease in 2015.

(18) Supplemental Cash Flow Information

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

	2015	2014	2013
Supplemental cash flow information:			
Interest paid, net of amounts capitalized	$ 177	$ 167	$ 132
Income taxes received, net	$ 630	$ 153	$ 42
Supplemental disclosure of non-cash investing transactions:			
Accounts payable related to utility plant additions	$ 249	$ 128	$ 117

(19) Related Party Transactions

The companies identified as affiliates of MidAmerican Funding are Berkshire Hathaway and its subsidiaries, including BHE and its subsidiaries. The basis for the following transactions is provided for in service agreements between MidAmerican Funding and the affiliates.

MidAmerican Funding is reimbursed for charges incurred on behalf of its affiliates. The majority of these reimbursed expenses are for allocated general costs, such as insurance and building rent, and for employee wages, benefits and costs for corporate functions, such as information technology, human resources, treasury, legal and accounting. The amount of such reimbursements was $35 million, $37 million and $28 million for 2015, 2014 and 2013, respectively.

MidAmerican Funding reimbursed BHE in the amount of $7 million, $8 million and $10 million in 2015, 2014 and 2013, respectively, for its share of corporate expenses.

MidAmerican Energy purchases natural gas transportation and storage capacity services from Northern Natural Gas Company, a wholly owned subsidiary of BHE, and coal transportation services from BNSF Railway Company, a wholly-owned subsidiary of Berkshire Hathaway, in the normal course of business at either tariffed or market prices. These purchases totaled $165 million, $144 million and $155 million in 2015, 2014 and 2013, respectively.

MHC has a $300 million revolving credit arrangement carrying interest at the 30-day LIBOR rate plus a spread to borrow from BHE. Outstanding balances are unsecured and due on demand. The outstanding balance was $139 million at an interest rate of 0.494% as of December 31, 2015, and $136 million at an interest rate of 0.408% as of December 31, 2014, and is reflected as note payable to affiliate on the Consolidated Balance Sheet.

BHE has a $100 million revolving credit arrangement, carrying interest at the 30-day LIBOR rate plus a spread to borrow from MHC. Outstanding balances are unsecured and due on demand. There were no borrowings outstanding throughout 2015 and 2014.

MidAmerican Funding had accounts receivable from affiliates of $7 million as of December 31, 2015 and 2014, respectively, that are included in receivables, net on the Consolidated Balance Sheets. MidAmerican Funding also had accounts payable to affiliates of $12 million and $12 million as of December 31, 2015 and 2014, respectively, that are included in accounts payable on the Consolidated Balance Sheets.

MidAmerican Funding is party to a tax-sharing agreement and is part of the Berkshire Hathaway United States federal income tax return. As of December 31, 2015 and 2014, MidAmerican Funding had current federal and state income taxes receivable from BHE of $102 million and $296 million, respectively. MidAmerican Funding received net cash receipts for federal and state income taxes from BHE totaling $631 million, $154 million and $42 million for the years ended December 31, 2015, 2014 and 2013, respectively.

MidAmerican Funding recognizes the full amount of the funded status for its pension and postretirement plans, and amounts attributable to MidAmerican Funding's affiliates that have not previously been recognized through income are recognized as an intercompany balance with such affiliates. MidAmerican Funding adjusts these balances when changes to the funded status of the respective plans are recognized and does not intend to settle the balances currently. Amounts receivable from affiliates attributable to the funded status of employee benefit plans totaled $10 million and $13 million as of December 31, 2015 and 2014, respectively, and similar amounts payable to affiliates totaled $29 million and $30 million as of December 31, 2015 and 2014, respectively. See Note 10 for further information pertaining to pension and postretirement accounting.

The indenture pertaining to MidAmerican Funding's long-term debt restricts MidAmerican Funding from paying a distribution on its equity securities, unless after making such distribution either its debt to total capital ratio does not exceed 0.67:1 and its interest coverage ratio is not less than 2.2:1 or its senior secured long-term debt rating is at least BBB or its equivalent. MidAmerican Funding may seek a release from this restriction upon delivery to the indenture trustee of written confirmation from the ratings agencies that without this restriction MidAmerican Funding's senior secured long-term debt would be rated at least BBB+.

(20) Segment Information

MidAmerican Funding has identified three reportable operating segments: regulated electric, regulated gas and nonregulated energy. The regulated electric segment derives most of its revenue from regulated retail sales of electricity to residential, commercial, and industrial customers and from wholesale sales. The regulated gas segment derives most of its revenue from regulated retail sales of natural gas to residential, commercial, and industrial customers and also obtains revenue by transporting gas owned by others through its distribution system. Pricing for regulated electric and regulated gas sales are established separately by regulatory agencies; therefore, management also reviews each segment separately to make decisions regarding allocation of resources and in evaluating performance. The nonregulated energy segment derives most of its revenue from nonregulated retail electric and gas activities. Common operating costs, interest income, interest expense and income tax expense are allocated to each segment based on certain factors, which primarily relate to the nature of the cost. "Other" in the tables below consists of the nonregulated subsidiaries of MidAmerican Funding not engaged in the energy business and parent company interest expense. Refer to Note 9 for a discussion of items affecting income tax (benefit) expense for the regulated electric and gas operating segments.

The following tables provide information on a reportable segment basis (in millions):

	Years Ended December 31,		
	2015	2014	2013
Operating revenue:			
Regulated electric	$ 1,837	$ 1,817	$ 1,762
Regulated gas	661	996	824
Nonregulated energy	910	927	817
Other	12	22	10
Total operating revenue	$ 3,420	$ 3,762	$ 3,413
Depreciation and amortization:			
Regulated electric	$ 366	$ 312	$ 366
Regulated gas	41	39	37
Total depreciation and amortization	$ 407	$ 351	$ 403
Operating income:			
Regulated electric	$ 385	$ 319	$ 255
Regulated gas	64	75	74
Nonregulated energy	22	28	27
Other	2	1	1
Total operating income	$ 473	$ 423	$ 357
Interest expense:			
Regulated electric	$ 166	$ 157	$ 136
Regulated gas	17	17	15
Other	23	23	23
Total interest expense	$ 206	$ 197	$ 174
Income tax (benefit) expense:			
Regulated electric	$ (163)	$ (138)	$ (136)
Regulated gas	16	22	23
Nonregulated energy	6	12	10
Other	(3)	(6)	(7)
Total income tax (benefit) expense	$ (144)	$ (110)	$ (110)
Net income attributable to MidAmerican Funding:			
Regulated electric	$ 413	$ 361	$ 292
Regulated gas	33	40	41
Nonregulated energy	16	16	16
Other	(4)	(8)	(9)
Total net income attributable to MidAmerican Funding	$ 458	$ 409	$ 340
Utility construction expenditures:			
Regulated electric	$ 1,365	$ 1,429	$ 945
Regulated gas	81	97	81
Total utility construction expenditures	$ 1,446	$ 1,526	$ 1,026

	As of December 31,		
	2015	2014	2013
Total assets:			
Regulated electric	$ 14,161	$ 13,041	$ 11,712
Regulated gas	1,330	1,296	1,275
Nonregulated energy	164	167	131
Other	19	18	28
Total assets	$ 15,674	$ 14,522	$ 13,146

Goodwill by reportable segment as of December 31, 2015 and 2014, was as follows (in millions):

Regulated electric	$ 1,191
Regulated gas	79
Total	$ 1,270

(21) Transfer of Nonregulated Energy Operations

Refer to Note 21 of MidAmerican Energy's Notes to Financial Statements.

(22) Unaudited Quarterly Operating Results

	2015			
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	(In millions)			
Operating revenue	$ 951	$ 797	$ 921	$ 751
Operating income	107	122	211	33
Net income	99	129	231	(1)

	2014			
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	(In millions)			
Operating revenue	$ 1,230	$ 775	$ 864	$ 893
Operating income	153	51	161	58
Net income	155	30	168	56

Quarterly data reflect seasonal variations common to a Midwest utility.

Nevada Power Company and its subsidiaries
Consolidated Financial Section

Item 6. Selected Financial Data

Information required by Item 6 is omitted pursuant to General Instruction I(2)(a) to Form 10-K.

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

General

Nevada Power's revenues and operating income are subject to fluctuations during the year due to impacts that seasonal weather, rate changes, and customer usage patterns have on demand for electric energy and resources. Nevada Power is a summer peaking utility experiencing its highest retail energy sales in response to the demand for air conditioning. The variations in energy usage due to varying weather, customer growth and other energy usage patterns, including energy efficiency and conservation measures, necessitates a continual balancing of loads and resources and purchases and sales of energy under short- and long-term energy supply contracts. As a result, the prudent management and optimization of available resources has a direct effect on the operating and financial performance of Nevada Power. Additionally, the timely recovery of purchased power, fuel costs and other costs and the ability to earn a fair return on investments through rates are essential to the operating and financial performance of Nevada Power.

The following is management's discussion and analysis of certain significant factors that have affected the consolidated financial condition and results of operations of Nevada Power 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 Nevada Power's historical Consolidated Financial Statements and Notes to Consolidated Financial Statements in Item 8 of this Form 10-K. Nevada Power's actual results in the future could differ significantly from the historical results.

Results of Operations

Net income for the year ended December 31, 2015 was $288 million, an increase of $61 million, or 27% compared to 2014. Net income increased primarily due to lower impairment costs resulting from the settlement of the 2014 general rate case and certain assets not in rates of $31 million, higher electric margins from increased customer usage and growth and the impacts of weather of $28 million, lower other operating and maintenance of $35 million and lower interest expense of $18 million. The increase in net income was partially offset by higher depreciation and amortization of $23 million primarily due to higher regulatory amortizations.

Net income for the year ended December 31, 2014 was $227 million, an increase of $82 million, or 57% compared to 2013. Net income increased primarily due to $52 million in merger-related expense in 2013; $31 million of impairment charges in 2013 for certain assets not in rates; lower costs associated with major outages, planned maintenance and other generating costs; a one-time bill credit of $15 million to retail customers recorded in 2013 in connection with the BHE Merger; and disallowance by the PUCN of energy efficiency implementation revenues in 2013 due to Nevada Power earning in excess of its authorized rate of return in 2012; partially offset by $29 million of impairment charges in 2014 for certain assets not in rates and regulatory amortizations.

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

A comparison of Nevada Power's key operating results related to gross margin for the years ended December 31 is as follows:

	2015	2014	Change		2014	2013	Change	
Gross margin (in millions):								
Operating revenue	$ 2,402	$ 2,337	$ 65	3 %	$ 2,337	$ 2,092	$ 245	12 %
Cost of fuel, energy and capacity	1,084	1,076	8	1	1,076	835	241	29
Gross margin	$ 1,318	$ 1,261	$ 57	5	$ 1,261	$ 1,257	$ 4	—
GWh sold:								
Residential	9,246	8,923	323	4 %	8,923	9,012	(89)	(1)%
Commercial	4,635	4,489	146	3	4,489	4,426	63	1
Industrial	7,571	7,486	85	1	7,486	7,533	(47)	(1)
Other	214	211	3	1	211	212	(1)	—
Total retail	21,666	21,109	557	3	21,109	21,183	(74)	—
Wholesale	353	20	333	*	20	36	(16)	(44)
Total GWh sold	22,019	21,129	890	4	21,129	21,219	(90)	—
Average number of retail customers (in thousands):								
Residential	782	770	12	2 %	770	754	16	2 %
Commercial	104	102	2	2	102	103	(1)	(1)
Industrial	2	2	—	—	2	2	—	—
Total	888	874	14	2	874	859	15	2
Average revenue per MWh -								
Retail	$ 108.49	$ 108.90	$ (0.41)	— %	$ 108.90	$ 98.05	$ 10.85	11 %
Heating degree days	1,491	1,306	185	14 %	1,306	1,887	(581)	(31)%
Cooling degree days	4,069	3,970	99	2 %	3,970	3,766	204	5 %
Sources of energy (GWh)(1):								
Coal	1,556	4,422	(2,866)	(65)%	4,422	2,900	1,522	52 %
Natural gas	14,567	12,590	1,977	16	12,590	14,360	(1,770)	(12)
Other	4	15	(11)	(73)	15	33	(18)	(55)
Total energy generated	16,127	17,027	(900)	(5)	17,027	17,293	(266)	(2)
Energy purchased	6,431	5,424	1,007	19	5,424	4,748	676	14
Total	22,558	22,451	107	—	22,451	22,041	410	2
Average cost of energy per MWh:								
Energy generated(2)	$ 36.43	$ 36.68	$ (0.25)	(1)%	$ 36.68	$ 21.82	$ 14.86	68 %
Energy purchased	$ 77.17	$ 83.28	$ (6.11)	(7)%	$ 83.28	$ 96.42	$ (13.14)	(14)%

* Not meaningful

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

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

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

Gross margin increased $57 million for 2015 compared to 2014 due to:

- $26 million in higher energy efficiency program rate revenue, which is offset in operating and maintenance expense;
- $14 million due to higher customer growth in 2015;
- $14 million due to higher customer usage in 2015, primarily due to the impacts of weather; and
- $3 million in transmission revenue primarily due to increased ON Line usage.

Operating and maintenance decreased $40 million, or 10%, for 2015 compared to 2014 due to $31 million of lower impairment costs resulting from the settlement of the general rate case in 2014 and certain assets not in rates, $18 million of decreased amortizations for demand side management program costs, changes in contingent liabilities, a decrease related to the retirement of Reid Gardner Generating Station Units 1-3 and lower compensation costs. The decrease was offset by $35 million in ON Line lease expense and $26 million in higher energy efficiency program costs, which are fully recovered in operating revenue.

Depreciation and amortization increased $23 million, or 8%, for 2015 compared to 2014 due to higher regulatory amortizations as a result of the 2014 general rate case effective January 2015 and the acquisition of Reid Gardner Generating Station Unit 4 in 2014.

Property and other taxes increased $2 million, or 5%, for 2015 compared to 2014 primarily due to a new state commerce tax.

Other income (expense) is favorable $21 million, or 11%, for 2015 compared to 2014 due to redemption of $250 million Series L, 5.875% General and Refunding Mortgage Notes in January 2015, increased allowance for borrowed and equity funds and higher interest on deferred charges in 2015.

Income tax expense increased $32 million, or 25%, for 2015 compared to 2014. The effective tax rate was 36% in 2015 and 2014.

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

Gross margin increased $4 million for 2014 compared to 2013 primarily due to:

- $15 million due to a one-time bill credit to retail customers in connection with the BHE Merger in 2013;
- $13 million due to customer growth; and
- $11 million in transmission revenue primarily due to ON Line being placed in-service in December 2013.

The increase was partially offset by:

- $18 million in lower residential customer usage in 2014 and
- $14 million in lower energy efficiency program rate revenue, which is offset in operating and maintenance expense.

Operating and maintenance decreased $50 million, or 11%, for 2014 compared to 2013 primarily due to $31 million of impairment charges in 2013 for certain assets not in rates; lower costs associated with major outages, planned maintenance and other generating costs; energy efficiency program costs, which are fully recovered in operating revenue; an $11 million disallowance by the PUCN of energy efficiency implementation revenues in 2013 due to Nevada Power earning in excess of its authorized rate of return in 2012 (including carrying charges); and compensation costs. The decrease is partially offset by $29 million of impairment charges in 2014 for certain assets not in rates and regulatory amortizations.

Depreciation and amortization decreased $3 million, or 1%, for 2014 compared to 2013 primarily due to regulatory amortizations.

Property and other taxes increased $3 million, or 8%, for 2014 compared to 2013 primarily due to an increase in franchise taxes and an increase in property tax assessed value.

Nevada Power incurred costs totaling $52 million in 2013 related to the BHE Merger, consisting of amounts payable under NV Energy's accelerated vesting and stock compensation under NV Energy's long-term incentive plan of $18 million; change in control policy of $15 million; investment banker fees paid by NV Energy of $15 million and legal and other expenses.

Other income (expense) is favorable $12 million, or 6%, for 2014 compared to 2013 as a result of using cash on hand to repay existing debt in July and December 2013, $8 million gain on sale of property and stock, higher net interest earned on regulatory items and lower amortization of debt expenses, partially offset by lower allowance for debt and equity funds used during construction due to assets placed in-service, including ON Line being placed in-service December 2013.

Income tax expense increased $36 million, or 38%, for 2014 compared to 2013 due to higher income before income tax expense. The effective tax rate was 36% in 2014 and 39% in 2013. The decrease in the effective tax rate is due to the effects of certain non-deductible merger related costs in 2013.

Liquidity and Capital Resources

As of December 31, 2015, Nevada Power's total net liquidity was $936 million as follows (in millions):

Cash and cash equivalents	$ 536
Credit facilities[1]	400
Less:	
Short-term debt	—
Letters of credit and tax exempt bond support	—
Net credit facilities	400
Total net liquidity	$ 936
Credit facilities:	
Maturity dates	March 2018

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

In January 2015, Nevada Power issued a notice of redemption to the bondholders for its $250 million, 5.875% Series L General and Refunding Mortgage Securities and redeemed the aggregate principal amount outstanding of $250 million at 100% of the principal amount plus accrued interest with the use of cash on hand and short-term borrowings of $75 million.

Operating Activities

Net cash flows from operating activities for the years ended December 31, 2015 and 2014 were $892 million and $704 million, respectively. The change was due to deferred energy from lower fuel costs, increased customer growth and usage, higher collections of energy efficiency program costs and a payment in 2014 of the bill credit to customers as a result of the BHE Merger. The increase was offset by refunds to customers for renewable energy programs, timing of projects under long-term service agreements which are offset in investing activities, higher payments for asset retirement obligations and settlement payments of contingent liabilities.

Net cash flows from operating activities for the years ended December 31, 2014 and 2013 were $704 million and $548 million, respectively. The change was primarily due to lower deferred energy refunded to customers, higher collections for energy costs, lower payments for merger costs and lower compensation payments, offset by lower collections from customers for conservation and renewable programs, payment in 2014 of the bill credit to customers as a result of the BHE Merger, and higher coal purchases and generation inventory resulting from the acquisition of natural gas fueled generating facilities.

The timing of Nevada Power's income tax cash flows from period to period can be significantly affected by the estimated federal income tax payment methods and assumptions for each payment date.

In December 2015, the Protecting Americans from Tax Hikes Act of 2015 ("PATH") was signed into law, extending bonus depreciation for qualifying property acquired and placed in-service before January 1, 2020 (bonus depreciation rates will be 50% for 2015-2017, 40% in 2018, and 30% in 2019), with an additional year for certain longer lived assets. Investment tax credits were extended and phased-down for solar projects that are under construction before the end of 2021 (investment tax credit rates are 30% through 2019, 26% in 2020 and 22% in 2021; they revert to the statutory rate of 10% thereafter). As a result of PATH, Nevada Power's cash flows from operations are expected to benefit in 2016 and beyond due to bonus depreciation on qualifying assets placed in-service and investment tax credits (once the net operating loss is fully utilized) earned on qualifying projects.

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, Nevada Power'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, 2015 and 2014 were $(301) million and $(371) million, respectively. The change was primarily due to the acquisition of the Las Vegas and Sun Peak Generating Stations in 2014, offset by construction of the Nellis Solar Array in 2015, timing of projects under long-term service agreements which are offset in operating activities and proceeds received from the sale of assets and an equity investment.

Net cash flows from investing activities for the years ended December 31, 2014 and 2013 were $(371) million and $(216) million, respectively. The change was primarily due to the acquisition of the Las Vegas and Sun Peak Generating Stations.

Financing Activities

Net cash flows from financing activities for the years ended December 31, 2015 and 2014 were $(275) million and $(239) million, respectively. The change was due to repayments of long-term debt and capital lease obligations, offset by lower dividends paid to NV Energy.

Net cash flows from financing activities for the years ended December 31, 2014 and 2013 were $(239) million and $(407) million, respectively. The change was primarily due to lower repayments of long-term debt, partially offset by higher dividends paid to NV Energy.

Ability to Issue Debt

Nevada Power's ability to issue debt is primarily impacted by its financing authority from the PUCN. As of December 31, 2015, Nevada Power has financing authority from the PUCN consisting of the ability to: (1) issue additional long-term debt securities of up to $725 million; (2) refinance up to $553 million of long-term debt securities; and (3) maintain a revolving credit facility of up to $1.3 billion. Nevada Power's revolving credit facility contains a financial maintenance covenant which Nevada Power was in compliance with as of December 31, 2015. In addition, certain financing agreements contain covenants which are currently suspended as Nevada Power's senior secured debt is rated investment grade. However, if Nevada Power's senior secured debt ratings fall below investment grade by either Moody's Investor Service or Standard & Poor's, Nevada Power would be subject to limitations under these covenants.

Ability to Issue General and Refunding Mortgage Securities

To the extent Nevada Power has the ability to issue debt under the most restrictive covenants in its financing agreements and has financing authority to do so from the PUCN, Nevada Power's ability to issue secured debt is limited by the amount of bondable property or retired bonds that can be used to issue debt under Nevada Power's indenture.

Nevada Power's indenture creates a lien on substantially all of Nevada Power's properties in Nevada. As of December 31, 2015, $8.7 billion of Nevada Power's assets were pledged. Nevada Power had the capacity to issue $2.8 billion of additional general and refunding mortgage securities as of December 31, 2015 determined on the basis of 70% of net utility property additions. Property additions include plant-in-service and specific assets in construction work-in-progress. The amount of bond capacity listed above does not include eligible property in construction work-in-progress. Nevada Power also has the ability to release property from the lien of Nevada Power's indenture on the basis of net property additions, cash or retired bonds. To the extent Nevada Power releases property from the lien of Nevada Power's indenture, it will reduce the amount of securities issuable under the indenture.

Future Uses of Cash

Capital Expenditures

Nevada Power 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 and associated operating costs are generally incorporated into Nevada Power's regulated retail rates. Expenditures for certain assets may ultimately include acquisition of existing assets.

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

	Historical			Forecasted		
	2013	2014	2015	2016	2017	2018
Generation development	$ 81	$ 201	$ 45	$ 6	$ 87	$ 19
Distribution	57	107	102	65	74	90
Transmission system investment	50	19	63	35	7	22
Other	45	44	110	115	86	87
Total	$ 233	$ 371	$ 320	$ 221	$ 254	$ 218

Nevada Power's approved forecast capital expenditures include the following:

- Generation development investment includes the purchase of the remaining 25% interest in the Silverhawk generating facility in 2017. Nevada Power’s cost for the remaining interest will total $77 million. In December 2015, the PUCN approved the purchase of the facility in Nevada Power’s triennial IRP filing.
- 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.

Contractual Obligations

Nevada Power has contractual cash obligations that may affect its consolidated financial condition. The following table summarizes Nevada Power's material contractual cash obligations as of December 31, 2015 (in millions):

	Payments Due by Periods				
	2016	2017 - 2018	2019 - 2020	2021 and Thereafter	Total
Long-term debt	$ 210	$ 823	$ 500	$ 1,292	$ 2,825
Interest payments on long-term debt(1)	171	319	169	1,336	1,995
Capital leases, including interest(2),(3)	11	24	26	62	123
ON Line financial lease, including interest(2)	44	88	86	809	1,027
Fuel and capacity contract commitments(1)	612	808	658	4,587	6,665
Fuel and capacity contract commitments (not commercially operable)(1)	—	43	53	603	699
Operating leases and easements(1)	11	16	14	67	108
Asset retirement obligations	13	28	15	44	100
Maintenance, service and other contracts(1)	46	154	72	109	381
Total contractual cash obligations	$ 1,118	$ 2,303	$ 1,593	$ 8,909	$ 13,923

(1) Not reflected on the Consolidated Balance Sheets.

(2) Interest is not reflected on the Consolidated Balance Sheets.

(3) Includes fuel and capacity contracts designated as a capital lease.

Nevada Power has other types of commitments that arise primarily from unused lines of credit, letters of credit or relate to construction and other development costs (Liquidity and Capital Resources included within this Item 7 and Note 6) and uncertain tax positions (Note 10), which have not been included in the above table because the amount and timing of the cash payments are not certain. Additionally, refer to Note 14 for equity commitments related to solar projects currently under construction. Refer, where applicable, to the respective referenced note in Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Regulatory Matters

Nevada Power is subject to comprehensive regulation. Refer to the discussion contained in Item 1 of this Form 10-K for further discussion regarding Nevada Power's general regulatory framework and current regulatory matters.

Environmental Laws and Regulations

Nevada Power 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 Nevada Power'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. Nevada Power 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. Environmental laws and regulations continue to evolve, and Nevada Power is unable to predict the impact of the changing laws and regulations on its operations and financial results. Refer to "Liquidity and Capital Resources" for discussion of Nevada Power's forecasted environmental-related capital expenditures.

Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for additional information regarding environmental laws and regulations and "Liquidity and Capital Resources" for Nevada Power's forecasted environmental-related capital expenditures.

Collateral and Contingent Features

Debt of Nevada Power is rated by credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of Nevada Power's ability to, in general, meet the obligations of its issued debt. 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.

Nevada Power 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. Nevada Power's secured revolving credit facility does not require the maintenance of a minimum credit rating level in order to draw upon its availability. However, commitment fees and interest rates under the credit facility 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.

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 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," or in some cases terminate the contract, in the event of a material adverse change in creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2015, the applicable credit ratings from the three recognized credit rating agencies were investment grade. If all credit-risk-related contingent features or adequate assurance provisions for these agreements had been triggered as of December 31, 2015, Nevada Power would have been required to post $71 million of additional collateral. Nevada Power'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 8 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for a discussion of Nevada Power's collateral requirements specific to Nevada Power'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.

Nevada Power 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 Nevada Power. 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. Nevada Power qualifies or believes it will qualify for many of these exemptions. Nevada Power 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 Nevada Power or could have impacts to energy and other markets in general that could have an impact on Nevada Power's consolidated financial results.

Inflation

Historically, overall inflation and changing prices in the economies where Nevada Power operates has not had a significant impact on Nevada Power's consolidated financial results. Nevada Power operates under a cost-of-service based rate structure administered by the PUCN and the FERC. Under this rate structure, Nevada Power is allowed to include prudent costs in its rates, including the impact of inflation after Nevada Power experiences cost increases. Fuel and purchase power costs are recovered through a balancing account, minimizing the impact of inflation related to these costs. Nevada Power attempts to minimize the potential impact of inflation on its operations through the use of periodic rate adjustments for fuel and energy costs, 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.

New Accounting Pronouncements

For a discussion of new accounting pronouncements affecting Nevada Power, 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 Nevada Power's methods, judgments and assumptions used in the preparation of the Consolidated Financial Statements and should be read in conjunction with Nevada Power's Summary of Significant Accounting Policies included in Nevada Power's 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

Nevada Power prepares its Consolidated Financial Statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, Nevada Power 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 regulated 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 regulated rates occur.

Nevada Power continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future regulated 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 Nevada Power's ability to recover its costs. Nevada Power believes the application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in future regulated 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 regulated rates, the related regulatory assets and liabilities will be written off to net income, returned to customers or re-established as accumulated other comprehensive income (loss). Total regulatory assets were $1.1 billion and total regulatory liabilities were $477 million as of December 31, 2015. Refer to Nevada Power's Note 5 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding Nevada Power's regulatory assets and liabilities.

Derivatives

Nevada Power is exposed to the impact of market fluctuations in commodity prices and interest rates. Nevada Power is principally exposed to electricity, natural gas and coal market fluctuations primarily through Nevada Power's obligation to serve retail customer load in its regulated service territory. Nevada Power'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. The actual cost of fuel and purchased power is recoverable through the deferred energy mechanism. Interest rate risk exists on variable-rate debt and future debt issuances.

Nevada Power has established a risk management process that is designed to identify, assess, manage, mitigate, monitor and report each of the various types of risk involved in its business. Nevada Power employs a number of different derivative contracts, which may include forwards, futures, options, swaps and other agreements, to manage its commodity price and interest rate risk. Nevada Power 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, Nevada Power may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate Nevada Power's exposure to interest rate risk. Nevada Power does not hedge all of its commodity price and interest rate risks, thereby exposing the unhedged portion to changes in market prices. Refer to Nevada Power's Note 8 and 9 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding Nevada Power'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 Nevada Power transacts. When quoted prices for identical contracts are not available, Nevada Power uses forward price curves. Forward price curves represent Nevada Power's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates.

Nevada Power bases its forward price curves upon internally developed models, with internal and external fundamental data inputs. Market price quotations for electricity and natural gas trading hubs are not as readily obtainable due to markets that are not active. Given that limited market data exists for these contracts, Nevada Power 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 model incorporates a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical expedient for valuing its assets and liabilities measured and reported at fair value. The determination of the fair value for derivative contracts not only includes counterparty risk, but also the impact of Nevada Power's nonperformance risk on its liabilities, which as of December 31, 2015, had an immaterial impact to the fair value of its derivative contracts. As such, Nevada Power considers its derivative contracts to be valued using Level 3 inputs. 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, 2015, Nevada Power had a net derivative liability of $22 million related to contracts where Nevada Power uses internal models with significant unobservable inputs.

Classification and Recognition Methodology

Nevada Power's commodity derivative contracts are probable of inclusion in regulated rates, and changes in the estimated fair value of derivative contracts are recorded as regulatory assets. Accordingly, amounts are generally not recognized in earnings until the contracts are settled and the amounts are reflected in regulated rates. As of December 31, 2015, Nevada Power had $22 million recorded as a regulatory asset related to derivative contracts on the Consolidated Balance Sheets.

Impairment of Long-Lived Assets

Nevada Power evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As substantially all property, plant and equipment was used in regulated businesses as of December 31, 2015, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

The estimate of cash flows arising from the future use of the asset that are used in the impairment analysis requires judgment regarding what Nevada Power would expect to recover from the future use of the asset. Changes in judgment that could significantly alter the calculation of the fair value or the recoverable amount of the asset may result from significant changes in the regulatory environment, the business climate, management's plans, legal factors, market price of the asset, the use of the asset or the physical condition of the asset, future market prices, load growth, competition and many other factors over the life of the asset. Any resulting impairment loss is highly dependent on the underlying assumptions and could significantly affect Nevada Power's results of operations.

Income Taxes

In determining Nevada Power's income taxes, management is required to interpret complex income tax laws and regulations, which includes consideration of regulatory implications imposed by Nevada Power's various regulatory jurisdictions. Nevada Power'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. Nevada Power 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 Nevada Power's federal, state and local income tax examinations is uncertain, Nevada Power 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 Nevada Power's consolidated financial results. 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. Refer to Nevada Power's Note 10 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding Nevada Power's income taxes.

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 Nevada Power is required to pass on to its customers are charged or credited directly to a regulatory asset or liability. As of December 31, 2015, these amounts were recognized as regulatory assets of $149 million and regulatory liabilities of $10 million, and will be included in regulated 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 their last billing is estimated, and the corresponding unbilled revenue is recorded. Unbilled revenue was $116 million as of December 31, 2015. 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

Nevada Power's Consolidated Balance Sheets include assets and liabilities with fair values that are subject to market risks. Nevada Power's significant market risks are primarily associated with commodity prices, interest rates and the extension of credit to counterparties with which Nevada Power transacts. The following discussion addresses the significant market risks associated with Nevada Power's business activities. Nevada Power has established guidelines for credit risk management. Refer to Notes 2 and 8 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding Nevada Power's contracts accounted for as derivatives.

Commodity Price Risk

Nevada Power is exposed to the impact of market fluctuations in commodity prices and interest rates. Nevada Power is principally exposed to electricity, natural gas and coal market fluctuations primarily through Nevada Power's obligation to serve retail customer load in its regulated service territory. Nevada Power'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. The actual cost of fuel and purchased power is recoverable through the deferred energy mechanism. Interest rate risk exists on variable-rate debt and future debt issuances. Nevada Power does not engage in proprietary trading activities. To mitigate a portion of its commodity price risk, Nevada Power uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. Nevada Power does not hedge its commodity price risk, thereby exposing the unhedged portion to changes in market prices. Nevada Power's exposure to commodity price risk is generally limited by its ability to include commodity costs in regulated rates through its deferred energy mechanism, which is subject to disallowance and regulatory lag that occurs between the time the costs are incurred and when the costs are included in regulated rates, as well as the impact of any customer sharing resulting from cost adjustment mechanisms.

The table that follows summarizes Nevada Power's price risk on commodity contracts accounted for as derivatives, 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 Liability	Estimated Fair Value after Hypothetical Change in Price	
		10% increase	10% decrease
As of December 31, 2015			
Total commodity derivative contracts	$ (18)	$ (20)	$ (16)
As of December 31, 2014			
Total commodity derivative contracts	$ (25)	$ (29)	$ (21)

Nevada Power's commodity derivative contracts not designated as hedging contracts are recoverable from customers in regulated rates and, therefore, net unrealized gains and losses associated with interim price movements on commodity derivative contracts do not expose Nevada Power to earnings volatility. As of December 31, 2015, Nevada Power recorded a net regulatory asset of $22 million related to the net derivative liability of $22 million.

Interest Rate Risk

Nevada Power is exposed to interest rate risk on its outstanding variable-rate short- and long-term debt and future debt issuances. Nevada Power 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, Nevada Power's fixed-rate long-term debt does not expose Nevada Power 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 Nevada Power were to reacquire all or a portion of these instruments prior to their maturity. The nature and amount of Nevada Power'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 and 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional discussion of Nevada Power's short- and long-term debt.

As of December 31, 2015 and 2014, Nevada Power had short- and long-term variable-rate obligations totaling $76 million that expose Nevada Power to the risk of increased interest expense in the event of increases in short-term interest rates. If variable interest rates were to increase by 10% from December 31 levels, it would not have a material effect on Nevada Power's consolidated annual interest expense. The carrying value of the variable-rate obligations approximates fair value as of December 31, 2015 and 2014.

Credit Risk

Nevada Power 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 Nevada Power's counterparties have similar economic, industry or other characteristics and due to direct and indirect relationships among the counterparties. Before entering into a transaction, Nevada Power 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, Nevada Power enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtain third-party guarantees, letters of credit and cash deposits. If required, Nevada Power exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

As of December 31, 2015, Nevada Power's aggregate credit exposure from energy related transactions totaled $11 million, based on settlement and mark-to-market exposures, net of collateral. The majority of the exposure is comprised of one counterparty that is not rated by nationally recognized credit rating agencies.

Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Nevada Power Company
Las Vegas, Nevada

We have audited the accompanying consolidated balance sheets of Nevada Power Company and subsidiaries ("Nevada Power") as of December 31, 2015 and 2014, and the related consolidated statements of operations, changes in shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2015. These financial statements are the responsibility of Nevada Power's management. Our responsibility is to express an opinion on the 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. Nevada Power 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 Nevada Power'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 Nevada Power Company and subsidiaries as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Las Vegas, Nevada
February 26, 2016

NEVADA POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions, except share data)

	As of December 31,	
	2015	**2014**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 536	$ 220
Accounts receivable, net	265	243
Inventories	80	88
Regulatory assets	—	57
Other current assets	46	32
Total current assets	927	640
Property, plant and equipment, net	6,996	7,003
Regulatory assets	1,057	1,069
Other assets	37	46
Total assets	$ 9,017	$ 8,758
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Accounts payable	$ 214	$ 212
Accrued interest	54	60
Accrued property, income and other taxes	30	30
Regulatory liabilities	173	40
Current portion of long-term debt and financial and capital lease obligations	225	264
Customer deposits	58	55
Other current liabilities	28	36
Total current liabilities	782	697
Long-term debt and financial and capital lease obligations	3,060	3,280
Regulatory liabilities	304	326
Deferred income taxes	1,405	1,269
Other long-term liabilities	303	298
Total liabilities	5,854	5,870
Commitments and contingencies (Note 14)		
Shareholder's equity:		
Common stock - $1.00 stated value, 1,000 shares authorized, issued and outstanding	—	—
Other paid-in capital	2,308	2,308
Retained earnings	858	583
Accumulated other comprehensive loss, net	(3)	(3)
Total shareholder's equity	3,163	2,888
Total liabilities and shareholder's equity	$ 9,017	$ 8,758

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

NEVADA POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2015	**2014**	**2013**
Operating revenue	$ 2,402	$ 2,337	$ 2,092
Operating costs and expenses:			
Cost of fuel, energy and capacity	1,084	1,076	835
Operating and maintenance	365	405	455
Depreciation and amortization	297	274	277
Property and other taxes	43	41	38
Merger-related	—	—	52
Total operating costs and expenses	1,789	1,796	1,657
Operating income	613	541	435
Other income (expense):			
Interest expense	(190)	(208)	(215)
Allowance for borrowed funds	3	1	6
Allowance for equity funds	4	1	8
Other, net	20	22	5
Total other income (expense)	(163)	(184)	(196)
Income before income tax expense	450	357	239
Income tax expense	162	130	94
Net income	$ 288	$ 227	$ 145

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

NEVADA POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
(Amounts in millions, except shares)

	Common Stock		Other Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss, Net	Total Shareholder's Equity
	Shares	Amount				
Balance, December 31, 2012	1,000	$ —	$ 2,308	$ 619	$ (5)	$ 2,922
Net income	—	—	—	145	—	145
Dividends declared	—	—	—	(178)	—	(178)
Other	—	—	—	—	1	1
Balance, December 31, 2013	1,000	—	2,308	586	(4)	2,890
Net income	—	—	—	227	—	227
Dividends declared	—	—	—	(230)	—	(230)
Other	—	—	—	—	1	1
Balance, December 31, 2014	1,000	—	2,308	583	(3)	2,888
Net income	—	—	—	288	—	288
Dividends declared	—	—	—	(13)	—	(13)
Other	—	—	—	—	—	—
Balance, December 31, 2015	1,000	$ —	$ 2,308	$ 858	$ (3)	$ 3,163

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

NEVADA POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31,		
	2015	**2014**	**2013**
Cash flows from operating activities:			
Net income	$ 288	$ 227	$ 145
Adjustments to reconcile net income to net cash from operating activities:			
(Gain) loss on nonrecurring items	(3)	15	—
Depreciation and amortization	297	274	277
Deferred income taxes and amortization of investment tax credits	162	130	95
Allowance for equity funds	(4)	(1)	(8)
Changes in regulatory assets and liabilities	4	2	103
Deferred energy	176	(44)	(105)
Amortization of deferred energy	36	79	(54)
Other, net	13	68	69
Changes in other operating assets and liabilities:			
Accounts receivable and other assets	(40)	(19)	(5)
Inventories	9	(15)	10
Accounts payable and other liabilities	(46)	(12)	21
Net cash flows from operating activities	892	704	548
Cash flows from investing activities:			
Capital expenditures	(320)	(371)	(233)
Proceeds from sale of assets	9	—	14
Other, net	10	—	3
Net cash flows from investing activities	(301)	(371)	(216)
Cash flows from financing activities:			
Repayments of long-term debt and financial and capital lease obligations	(262)	(9)	(229)
Dividends paid	(13)	(230)	(178)
Net cash flows from financing activities	(275)	(239)	(407)
Net change in cash and cash equivalents	316	94	(75)
Cash and cash equivalents at beginning of period	220	126	201
Cash and cash equivalents at end of period	$ 536	$ 220	$ 126

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

(1) Organization and Operations

Nevada Power Company, together with its subsidiaries ("Nevada Power"), is a wholly owned subsidiary of NV Energy, Inc. ("NV Energy"), a holding company that also owns Sierra Pacific Power Company ("Sierra Pacific") and certain other subsidiaries. Nevada Power is a United States regulated electric utility company serving retail customers, including residential, commercial and industrial customers primarily in the Las Vegas, North Las Vegas, Henderson and adjoining areas. NV Energy is an indirect wholly owned subsidiary of Berkshire Hathaway Energy Company ("BHE"). BHE is 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 Nevada Power Company 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; recovery of long-lived assets; 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

Nevada Power prepares its Consolidated Financial Statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, Nevada Power 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 regulated 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 regulated rates occur.

Nevada Power continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future regulated 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 Nevada Power's ability to recover its costs. Nevada Power believes the application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in future regulated 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 regulated rates, the related regulatory assets and liabilities will be written off to net income, returned to customers or re-established as accumulated other comprehensive income (loss).

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 assets on the Consolidated Balance Sheets.

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 Nevada Power's assessment of the collectibility of amounts owed to Nevada Power by its customers. This assessment requires judgment regarding the ability of customers to pay or the outcome of any pending disputes. Nevada Power also has the ability to assess deposits on customers who have delayed payments or who are deemed to be a credit risk. 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):

	2015	2014	2013
Beginning balance	$ 14	$ 8	$ 8
Charged to operating costs and expenses, net	16	14	15
Write-offs, net	(17)	(8)	(15)
Ending balance	$ 13	$ 14	$ 8

Derivatives

Nevada Power employs a number of different derivative contracts, which may include forwards, futures, options, swaps and other agreements, to manage its commodity price 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 cost of fuel, energy and capacity on the Consolidated Statements of Operations.

For Nevada Power's derivatives not designated as hedging contracts, the settled amount is generally included in regulated 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 regulated rates are recorded as regulatory assets and liabilities.

Inventories

Inventories consist mainly of materials and supplies totaling $58 million as of December 31, 2015 and 2014, and fuel, which includes coal stock, stored natural gas and fuel oil, totaling $22 million and $30 million as of December 31, 2015 and 2014, respectively. The cost is determined using the average cost method. Materials are charged to inventory when purchased and are expensed or capitalized to construction work in process, as appropriate, when used. Fuel costs are recovered from retail customers through the base tariff energy rates and deferred energy accounting adjustment charges approved by the Public Utilities Commission of Nevada ("PUCN").

Property, Plant and Equipment, Net

General

Additions to property, plant and equipment are recorded at cost. Nevada Power capitalizes all construction-related material, direct labor and contract services, as well as indirect construction costs. Indirect construction costs include debt allowance for funds used during construction ("AFUDC"), and equity AFUDC, as applicable. 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. The cost of repairs and minor replacements are charged to expense when incurred with the exception of costs for generation plant maintenance under certain long-term service agreements. Costs under these agreements are expensed straight-line over the term of the agreements as approved by the PUCN.

Depreciation and amortization are generally computed by applying the composite or straight-line method based on either estimated useful lives or mandated recovery periods as prescribed by Nevada Power's various regulatory authorities. Depreciation studies are completed by Nevada Power to determine the appropriate group lives, net salvage and group depreciation rates. These studies are reviewed and rates are ultimately approved by the applicable regulatory commission. 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 a cost of removal regulatory liability on the Consolidated Balance Sheets. As actual removal costs are incurred, the associated liability is reduced.

Generally when Nevada Power 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 regulated facilities, are capitalized as a component of property, plant and equipment, with offsetting credits to the Consolidated Statements of Operations. The rate applied to construction costs is the lower of the PUCN allowed rate of return and rates computed based on guidelines set forth by the Federal Energy Regulatory Commission ("FERC"). After construction is completed, Nevada Power 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. Nevada Power's AFUDC rate used during 2015 and 2014 was 8.09%.

Asset Retirement Obligations

Nevada Power recognizes AROs when it has a legal obligation to perform decommissioning, reclamation or removal activities upon retirement of an asset. Nevada Power'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 on the Consolidated Balance Sheets.

Management's methodology to assess its legal obligation includes an inventory of assets by Nevada Power's system and components and a review of rights-of-way and easements, regulatory orders, leases and federal, state and local environmental laws. Additionally, management has determined evaporative ponds, dry ash landfills, fuel storage tanks, asbestos and oils treated with Poly Chlorinated Biphenyl have met the requirements for an ARO.

Impairment of Long-Lived Assets

Nevada Power evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As substantially all property, plant and equipment was used in regulated businesses as of December 31, 2015, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

Income Taxes

Berkshire Hathaway includes Nevada Power in its United States federal income tax return. Consistent with established regulatory practice, Nevada Power's provision for income taxes has been computed on a separate return 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 other comprehensive income ("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 Nevada Power is required to pass on to its customers are charged or credited directly to a regulatory asset or liability. As of December 31, 2015 and 2014, these amounts were recognized as regulatory assets of $149 million and $156 million, respectively, and regulatory liabilities of $10 million and $3 million, respectively, and will be included in regulated 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.

In determining Nevada Power's income taxes, management is required to interpret complex income tax laws and regulations, which includes consideration of regulatory implications imposed by Nevada Power's various regulatory jurisdictions. Nevada Power'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. Nevada Power 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 Nevada Power's federal, state and local income tax examinations is uncertain, Nevada Power 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 Nevada Power's consolidated financial results. 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.

Revenue Recognition

Revenue is recognized as electricity is delivered or services are provided. Revenue recognized includes billed and unbilled amounts. As of December 31, 2015 and 2014, unbilled revenue was $116 million and $111 million, respectively, and is included in accounts receivable, net on the Consolidated Balance Sheets. Rates are established by regulators or contractual arrangements. When preliminary rates are permitted to be billed prior to final approval by the applicable regulator, certain revenue collected may be subject to refund and a liability for estimated refunds is accrued. Nevada Power 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.

Nevada Power primarily buys energy and natural gas to satisfy its customer load requirements. Due to changes in retail customer load requirements, Nevada Power may not take physical delivery of the energy or natural gas. Nevada Power may sell the excess energy or natural gas to the wholesale market. In such instances, it is Nevada Power's policy to record such sales net in cost of fuel, energy and capacity.

Unamortized Debt Premiums, Discounts and Issuance Costs

Premiums, discounts and financing costs incurred for the issuance of long-term debt are amortized over the term of the related financing using the effective interest method.

Segment Information

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

New Accounting Pronouncements

In November 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2015-17, which amends FASB Accounting Standards Codification ("ASC") Topic 740, "Income Taxes". The amendments in this guidance require that deferred income tax liabilities and assets be classified as noncurrent in the balance sheet. This guidance is effective for interim and annual reporting periods beginning after December 15, 2016, with early adoption permitted, and may be adopted prospectively or retrospectively for each period presented to reflect the new guidance. Nevada Power early adopted this guidance as of December 31, 2015 under a retrospective method, resulting in decreases in current deferred income tax assets and noncurrent deferred income tax liabilities of $145 million as of December 31, 2014.

In April 2015, the FASB issued ASU No. 2015-03, which amends FASB ASC Subtopic 835-30, "Interest - Imputation of Interest." The amendments in this guidance require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability instead of as an asset. This guidance is effective for interim and annual reporting periods beginning after December 15, 2015, with early adoption permitted. This guidance must be adopted retrospectively, wherein the balance sheet of each period presented should be adjusted to reflect the new guidance. Nevada Power early adopted this guidance as of December 31, 2015 under a retrospective method, resulting in a decrease in other assets and long-term debt of $32 million as of December 31, 2014.

In May 2014, the FASB issued ASU No. 2014-09, which creates FASB 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. In August 2015, the FASB issued ASU No. 2015-14, which defers the effective date of ASU No. 2014-09 one year to interim and annual reporting periods beginning after December 15, 2017. This guidance may be adopted retrospectively or under a modified retrospective method where the cumulative effect is recognized at the date of initial application. Nevada Power is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and 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	2015	2014
Utility plant:			
Generation	25 - 80 years	$ 4,212	$ 4,034
Distribution	20 - 65 years	3,118	3,018
Transmission	45 - 65 years	1,788	1,757
General and intangible plant	5 - 65 years	694	669
Utility plant		9,812	9,478
Accumulated depreciation and amortization		(2,971)	(2,599)
Utility plant, net		6,841	6,879
Other non-regulated, net of accumulated depreciation and amortization	5 - 65 years	2	4
Plant, net		6,843	6,883
Construction work-in-progress		153	120
Property, plant and equipment, net		$ 6,996	$ 7,003

Almost all of Nevada Power's plant is subject to the ratemaking jurisdiction of the PUCN and the FERC. Nevada Power's depreciation and amortization expense, as authorized by the PUCN, stated as a percentage of the depreciable property balances as of December 31, 2015, 2014 and 2013 was 3.0%, 3.3% and 3.3%, respectively. Nevada Power is required to file a utility plant depreciation study every six years as a companion filing with the triennial general rate case filings.

Construction work-in-progress is related to the construction of regulated assets.

Impairment of Regulated Assets Not In Rates

Nevada Power recorded an impairment charge of $29 million and $31 million in operating and maintenance on the Consolidated Statements of Operations for the years ended December 31, 2014 and 2013, respectively, related to the recovery of certain assets not currently in rates. Included in the 2014 impairment is $19 million related to the settlement of the 2014 general rate case. Impairment of regulated assets not in rates were not material in 2015.

(4) Jointly Owned Utility Facilities

Under joint facility ownership agreements, Nevada Power, as tenants in common, has undivided interests in jointly owned generation and transmission facilities. Nevada Power 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 Nevada Power's share of the expenses of these facilities. The amounts shown in the table below represent Nevada Power's share in each jointly owned facility as of December 31, 2015 (dollars in millions):

	Nevada Power's Share	Facility In Service	Accumulated Depreciation	Construction Work-in-Progress
Silverhawk Generating Station	75%	$ 247	$ 58	$ 2
Navajo Generating Station	11	203	141	1
ON Line Transmission Line	24	144	8	1
Other Transmission Facilities	Various	68	28	—
Total		$ 662	$ 235	$ 4

(5) Regulatory Matters

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

	Weighted Average Remaining Life	2015	2014
Deferred income taxes[1]	28 years	$ 149	$ 156
Merger costs from 1999 merger	28 years	143	149
Decommissioning costs	7 years	121	113
Employee benefit plans[2]	10 years	98	85
Abandoned projects	4 years	91	107
Deferred operating costs	20 years	87	61
Asset retirement obligations	7 years	79	80
Legacy meters	17 years	64	68
Deferred energy costs	2 years	56	129
Other	Various	169	178
Total regulatory assets		$ 1,057	$ 1,126
Reflected as:			
Current assets		$ —	$ 57
Other assets		1,057	1,069
Total regulatory assets		$ 1,057	$ 1,126

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

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

Nevada Power had regulatory assets not earning a return on investment of $572 million and $788 million as of December 31, 2015 and 2014, respectively, related to deferred income taxes, merger costs from 1999 merger, asset retirement obligations, deferred operating costs, deferred excess energy costs, loss on reacquired debt, unrealized loss on regulated derivative contracts and a portion of abandoned projects. Regulatory assets not earning a return as of December 31, 2014 also included legacy meters.

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

	Weighted Average Remaining Life	**2015**	**2014**
Cost of removal[1]	34 years	$ 273	$ 295
Deferred energy costs	2 years	139	—
Energy efficiency program	1 year	34	25
Other	Various	31	46
Total regulatory liabilities		$ 477	$ 366
Reflected as:			
Current liabilities		$ 173	$ 40
Other long-term liabilities		304	326
Total regulatory liabilities		$ 477	$ 366

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

Deferred Energy

Nevada statutes permit regulated utilities to adopt deferred energy accounting procedures. The intent of these procedures is to ease the effect on customers of fluctuations in the cost of purchased natural gas, fuel and electricity and are subject to annual prudency review by the PUCN.

Under deferred energy accounting, to the extent actual fuel and purchased power costs exceed fuel and purchased power costs recoverable through current rates that excess is not recorded as a current expense on the Consolidated Statements of Operations but rather is deferred and recorded as a regulatory asset on the Consolidated Balance Sheets and is included in the table above as deferred energy costs. Conversely, a regulatory liability is recorded to the extent fuel and purchased power costs recoverable through current rates exceed actual fuel and purchased power costs and is included in the table above as deferred energy costs. These excess amounts are reflected in quarterly adjustments to rates and recorded as cost of fuel, energy and capacity in future time periods.

Energy Efficiency Implementation Rates and Energy Efficiency Program Rates

The PUCN authorizes an electric utility to recover lost revenue that is attributable to the measurable and verifiable effects associated with the implementation of efficiency and conservation programs approved by the PUCN through energy efficiency implementation rates ("EEIR"). As a result, Nevada Power files annually to adjust energy efficiency program rates ("EEPR") and EEIR for over- or under-collected balances, which are effective in October of the same year.

The PUCN's final order approving the BHE Merger stipulated that Nevada Power will not seek recovery of any lost revenue for calendar year 2013 and, for the calendar year 2014 in an amount that exceeds 50% of the lost revenue that Nevada Power could otherwise request. In February 2014, Nevada Power filed an application with the PUCN to reset the EEIR and EEPR. In June 2014, the PUCN accepted a stipulation to adjust the EEIR, as of July 1, 2014, to collect 50% of the estimated lost revenue that Nevada Power would otherwise be allowed to recover for the 2014 calendar year. The EEIR was effective from July through December 2014 and reset on January 1, 2015 and was in effect through September 2015.

In February 2015, Nevada Power filed an application to reset the EEIR and EEPR. In August 2015, the PUCN accepted a stipulation for Nevada Power to calculate the base EEIR using a revised methodology for calculating lost revenue and for Nevada Power to make a $5 million reduction to the EEPR revenue requirement to more accurately reflect the actual level of spending and to minimize any over collection from its customers. The reset of the EEIR and EEPR was effective October 1, 2015 and remains in effect through September 30, 2016. To the extent Nevada Power's earned rate of return exceeds the rate of return used to set base general rates, Nevada Power is required to refund to customers EEIR revenue collected. The current EEIR liability for Nevada Power is $18 million and $11 million, which is included in current regulatory liabilities on the Consolidated Balance Sheets as of December 31, 2015 and 2014, respectively.

General Rate Case

In May 2014, Nevada Power filed a general rate case with the PUCN. In July 2014, Nevada Power made its certification filing, which requested incremental annual revenue relief in the amount of $38 million, or an average price increase of 2%. In October 2014, Nevada Power reached a settlement agreement with certain parties agreeing to a zero increase in the revenue requirement. In October 2014, the PUCN issued an order in the general rate case filing that accepted the settlement. The order provides for increases in the fixed-monthly service charge for customers with a corresponding decrease in the base tariff general rate effective January 1, 2015. As a result of the order, Nevada Power recorded $15 million in asset impairments related to property, plant and equipment and $5 million of regulatory asset impairments, which are included in operating and maintenance on the Consolidated Statements of Operations for the year ended December 31, 2014. Additionally, Nevada Power recorded a $5 million gain in other, net on the Consolidated Statement of Operations for the year ended December 31, 2014 related to the disposition of property. In October 2014, a party filed a petition for reconsideration of the PUCN order. In November 2014, the PUCN granted the petition for reconsideration and reaffirmed the order issued in October 2014.

2013 FERC Transmission Rate Case

In May 2013, the Nevada Utilities, filed an application with the FERC to establish single system transmission and ancillary service rates. The combined filing requested incremental rate relief of $17 million annually to be effective January 1, 2014. In August 2013, the FERC granted the companies' request for a rate effective date of January 1, 2014 subject to refund, and set the case for hearing or settlement discussions. On January 1, 2014, Nevada Power implemented the filed rates in this case subject to refund as set forth in the FERC's order.

In September 2014, the Nevada Utilities, filed an unopposed settlement offer with the FERC on behalf of NV Energy and the intervening parties providing rate relief of $4 million. The settlement offer would resolve all outstanding issues related to this case. In addition, a preliminary order from the administrative law judge granting the motion for interim rate relief was issued, which authorizes Nevada Power to institute the interim rates effective September 1, 2014, and begin billing transmission customers under the settlement rates for service provided on and after that date. In January 2015, the FERC approved the settlement and refunds were issued.

(6) Credit Facility

Nevada Power has a $400 million secured credit facility expiring in March 2018. The credit facility, which is for general corporate purposes for the issuance of letters of credit, has a variable interest rate based on London Interbank Offered Rate or a base rate, at Nevada Power's option, plus a spread that varies based on Nevada Power's credit ratings for its senior secured long-term debt securities. As of December 31, 2015 and 2014, Nevada Power had no borrowings outstanding under the credit facility. Amounts due under Nevada Power's credit facility are collateralized by Nevada Power's general and refunding mortgage bonds. The credit facility requires Nevada Power's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.68 to 1.0 as of the last day of each quarter.

(7) Long-Term Debt and Financial and Capital Lease Obligations

Nevada Power's long-term debt consists of the following, including unamortized premiums, discounts and debt issuance costs, as of December 31 (dollars in millions):

	Par Value	2015	2014
General and Refunding Mortgage Securities:			
5.875% Series L, due 2015	$ —	$ —	$ 250
5.950% Series M, due 2016	210	210	209
6.500% Series O, due 2018	324	323	322
6.500% Series S, due 2018	499	498	497
7.125% Series V, due 2019	500	499	499
6.650% Series N, due 2036	367	356	356
6.750% Series R, due 2037	349	345	345
5.375% Series X, due 2040	250	247	247
5.450% Series Y, due 2041	250	235	234
Variable-rate series (2015-0.672% to 1.055%, 2014-0.455% to 0.464%):			
Pollution Control Revenue Bonds Series 2006A, due 2032	38	38	38
Pollution Control Revenue Bonds Series 2006, due 2036	38	37	37
Capital and financial lease obligations - 2.750% to 11.600%, due through 2054	497	497	510
Total long-term debt and financial and capital leases	$ 3,322	$ 3,285	$ 3,544
Reflected as:			
Current portion of long-term debt and financial and capital lease obligations		$ 225	$ 264
Long-term debt and financial and capital lease obligations		3,060	3,280
Total long-term debt and financial and capital leases		$ 3,285	$ 3,544

The consummation of the BHE Merger triggered mandatory redemption requirements under financing agreements of Nevada Power. As a result, Nevada Power offered to purchase $3.0 billion of debt at 101% of par. Debt with a par value totaling $5 million was tendered in January 2014 and paid with cash on hand. The tender offer expired in January 2014.

Annual Payment on Long-Term Debt and Financial and Capital Leases

The annual repayments of long-term debt and capital and financial leases for the years beginning January 1, 2016 and thereafter, are as follows (in millions):

	Long-term Debt	Capital and Financial Lease Obligations	Total
2016	$ 210	$ 73	$ 283
2017	—	75	75
2018	823	74	897
2019	500	75	575
2020	—	74	74
Thereafter	1,292	908	2,200
Total	2,825	1,279	4,104
Unamortized premium, discount and debt issuance cost	(37)	—	(37)
Executory costs	—	(129)	(129)
Amounts representing interest	—	(653)	(653)
Total	$ 2,788	$ 497	$ 3,285

The issuance of General and Refunding Mortgage Securities by Nevada Power is subject to PUCN approval and is limited by available property and other provisions of the mortgage indentures. As of December 31, 2015, approximately $8.7 billion (based on original cost) of Nevada Power's property was subject to the liens of the mortgages.

Financial and Capital Lease Obligations

- In 1984, Nevada Power entered into a 30-year capital lease for the Pearson Building with five, five-year renewal options beginning in year 2015. In February 2010, Nevada Power amended this capital lease agreement to include the lease of the adjoining parking lot and to exercise three of the five-year renewal options beginning in year 2015. There remain two additional renewal options which could extend the lease an additional ten years. Capital assets of $27 million and $28 million were included in property, plant and equipment, net as of December 31, 2015 and 2014, respectively.
- In 2007, Nevada Power entered into a 20-year lease, with three 10-year renewal options, to occupy land and building for its Beltway Complex operations center in southern Nevada. Nevada Power accounts for the building portion of the lease as a capital lease and the land portion of the lease as an operating lease. Nevada Power transferred operations to the facilities in June 2009. Capital assets of $7 million and $8 million were included in property, plant and equipment, net as of December 31, 2015 and 2014, respectively.
- Nevada Power has long-term energy purchase contracts which qualify as capital leases. The leases were entered into between the years 1989 and 1990 and firm operation occurred through 1993. The terms of the leases are for 30 years and expire between the years 2022-2023. Capital assets of $40 million and $44 million were included in property, plant and equipment, net as of December 31, 2015 and 2014, respectively.
- Nevada Power has master leasing agreements of which various pieces of equipment qualify as capital leases. The remaining equipment is treated as operating leases. Lease terms average seven years under the master lease agreement. Capital assets of $1 million were included in property, plant and equipment, net as of December 31, 2015 and 2014.
- ON Line was placed in-service on December 31, 2013. The Nevada Utilities entered into a long-term transmission use agreement, in which the Nevada Utilities have 25% interest and Great Basin Transmission South, LLC has 75% interest. Refer to Note 4 for additional information. The Nevada Utilities' share of the long-term transmission use agreement and ownership interest is split at 95% for Nevada Power and 5% for Sierra Pacific. The term is for 41 years with the agreement ending December 31, 2054. Payments began on January 31, 2014. ON Line assets of $410 million and $418 million were included in property, plant and equipment, net as of December 31, 2015 and 2014, respectively.

(8) Risk Management and Hedging Activities

Nevada Power is exposed to the impact of market fluctuations in commodity prices and interest rates. Nevada Power is principally exposed to electricity, natural gas and coal market fluctuations primarily through Nevada Power's obligation to serve retail customer load in its regulated service territory. Nevada Power'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. The actual cost of fuel and purchased power is recoverable through the deferred energy mechanism. Interest rate risk exists on variable-rate debt and future debt issuances. Nevada Power does not engage in proprietary trading activities.

Nevada Power has established a risk management process that is designed to identify, assess, manage, mitigate, monitor and report each of the various types of risk involved in its business. To mitigate a portion of its commodity price risk, Nevada Power uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. Nevada Power 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, Nevada Power may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate Nevada Power's exposure to interest rate risk. Nevada Power 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 Nevada Power's accounting policies related to derivatives. Refer to Notes 2 and 9 for additional information on derivative contracts.

The following table, which excludes contracts that have been designated as normal under the normal purchases or normal sales exception afforded by GAAP, summarizes the fair value of Nevada Power'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 Liabilities	Other Long-term Liabilities	Total
As of December 31, 2015			
Commodity liabilities(1)	$ (8)	$ (14)	$ (22)
As of December 31, 2014			
Commodity liabilities(1)	$ (9)	$ (21)	$ (30)

(1) Nevada Power's commodity derivatives not designated as hedging contracts are included in regulated rates and as of December 31, 2015 and 2014, a regulatory asset of $22 million and $30 million, respectively, was recorded related to the derivative liability of $22 million and $30 million, respectively.

Derivative Contract Volumes

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

	Unit of Measure	2015	2014
Electricity sales	Megawatt hours	(2)	(3)
Natural gas purchases	Decatherms	126	115

Credit Risk

Nevada Power 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 Nevada Power's counterparties have similar economic, industry or other characteristics and due to direct and indirect relationships among the counterparties. Before entering into a transaction, Nevada Power analyzes the financial condition of each significant wholesale counterparty, establish limits on the amount of unsecured credit to be extended to each counterparty and evaluate the appropriateness of unsecured credit limits on an ongoing basis. To further mitigate wholesale counterparty credit risk, Nevada Power enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtain third-party guarantees, letters of credit and cash deposits. If required, Nevada Power 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 unsecured debt as reported by one or more of the three recognized credit rating agencies. These derivative contracts may either specifically provide rights to demand cash or other security in the event of a credit rating downgrade ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance," in the event of a material adverse change in creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2015, credit ratings from the three recognized credit rating agencies were investment grade.

The aggregate fair value of Nevada Power's derivative contracts in liability positions with specific credit-risk-related contingent features was $3 million, which represents the amount of collateral to be posted if all credit risk related contingent features for derivative contracts in liability positions had been triggered. Nevada Power's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation or other factors.

(9) Fair Value Measurements

The carrying value of Nevada Power'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. Nevada Power has various financial assets and liabilities that are measured at fair value on the Consolidated Balance Sheets 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 Nevada Power 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 Nevada Power's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. Nevada Power develops these inputs based on the best information available, including its own data.

The following table presents Nevada Power'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	Total
As of December 31, 2015				
Assets - investment funds	$ 5	$ —	$ —	$ 5
Liabilities - commodity derivatives	$ —	$ —	$ (22)	$ (22)
As of December 31, 2014				
Assets - investment funds	$ 20	$ —	$ —	$ 20
Liabilities - commodity derivatives	$ —	$ —	$ (30)	$ (30)

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 Nevada Power transacts. When quoted prices for identical contracts are not available, Nevada Power uses forward price curves. Forward price curves represent Nevada Power's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. Nevada Power bases its forward price curves upon internally developed models, with internal and external fundamental data inputs. Market price quotations for certain electricity and natural gas trading hubs are not as readily obtainable due to markets that are not active. Given that limited market data exists for these contracts, Nevada Power uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on unobservable inputs. The model incorporates a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical expedient for valuing its assets and liabilities measured and reported at fair value. Interest rate swaps are valued using a financial model which utilizes observable inputs for similar instruments based primarily on market price curves. The determination of the fair value for derivative contracts not only includes counterparty risk, but also the impact of Nevada Power's nonperformance risk on its liabilities, which as of December 31, 2015, had an immaterial impact to the fair value of its derivative contracts. As such, Nevada Power considers its derivative contracts to be valued using Level 3 inputs. Refer to Note 8 for further discussion regarding Nevada Power's risk management and hedging activities.

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

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

	2015	2014
Beginning balance	$ (30)	$ (47)
Changes in fair value recognized in regulatory assets	—	9
Purchases	—	—
Settlements	8	8
Ending balance	$ (22)	$ (30)

Nevada Power's long-term debt is carried at cost on the Consolidated Balance Sheets. The fair value of Nevada Power'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 Nevada Power'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 Nevada Power's long-term debt as of December 31 (in millions):

	2015		2014	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 2,788	$ 3,240	$ 3,034	$ 3,712

(10) Income Taxes

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

	2015	2014	2013
Current – Federal	$ —	$ —	$ (1)
Deferred – Federal	163	131	96
Investment tax credits	(1)	(1)	(1)
Total income tax expense	$ 162	$ 130	$ 94

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

	2015	2014	2013
Federal statutory income tax rate	35%	35%	35%
Non-deductible BHE Merger related expenses	—	—	3
Effects of ratemaking	1	1	1
Effective income tax rate	36%	36%	39%

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

	2015	2014
Deferred income tax assets:		
Federal net operating loss and credit carryforwards	$ 15	$ 158
Capital and financial leases	174	178
Employee benefits	30	22
Regulatory liabilities	47	37
Other	39	57
Total deferred income tax assets	305	452
Valuation allowance	(5)	(2)
Total deferred income tax assets, net	300	450
Deferred income tax liabilities:		
Property related items	(1,242)	(1,175)
Regulatory assets	(275)	(341)
Capital and financial leases	(169)	(174)
Other	(19)	(29)
Total deferred income tax liabilities	(1,705)	(1,719)
Net deferred income tax liability	$ (1,405)	$ (1,269)

The following table provides Nevada Power's federal net operating loss and tax credit carryforwards and expiration dates as of December 31, 2015 (in millions):

Net operating loss carryforwards	$ 4
Deferred income taxes on federal net operating loss carryforwards	$ 1
Expiration dates	2031 - 2035
Other tax credits	$ 14
Expiration dates	2016 - 2035

The United States federal jurisdiction is the only significant income tax jurisdiction for NV Energy. In July 2012, the United States Internal Revenue Service and the Joint Committee on Taxation concluded their examination of NV Energy with respect to its United States federal income tax returns for December 31, 2005 through December 31, 2008.

(11) Related Party Transactions

Kern River Gas Transmission Company, an indirect subsidiary of BHE, provided natural gas transportation and other services to Nevada Power of $68 million for each of the years ended December 31, 2015, 2014 and 2013. As of December 31, 2015 and 2014, Nevada Power's Consolidated Balance Sheets included amounts due to Kern River Gas Transmission Company of $5 million.

Nevada Power provided electricity and other services to PacifiCorp, an indirect subsidiary of BHE, of $3 million for each of the years ended December 31, 2015, 2014 and 2013. There were no receivables associated with these services as of December 31, 2015 and 2014. PacifiCorp provided electricity and the sale of renewable energy credits to Nevada Power of $2 million, $5 million and $2 million for the years ended December 31, 2015, 2014 and 2013, respectively. Payables associated with these transactions were $- million and $4 million as of December 31, 2015 and 2014, respectively.

Nevada Power provided electricity to Sierra Pacific of $69 million, $33 million and $36 million for the years ended December 31, 2015, 2014 and 2013, respectively. Receivables associated with these transactions were $15 million and $7 million as of December 31, 2015 and 2014, respectively. Nevada Power purchased electricity from Sierra Pacific of $2 million, $8 million and $1 million for the years ended December 31, 2015, 2014 and 2013, respectively. Payables associated with these transactions were $1 million and $- million as of December 31, 2015 and 2014, respectively.

Nevada Power incurs intercompany administrative and shared facility costs with NV Energy and Sierra Pacific. These transactions are governed by an intercompany service agreement and are priced at cost. Nevada Power provided services to NV Energy of $1 million, $1 million, and $- million for the years ending December 31, 2015, 2014 and 2013, respectively. NV Energy provided services to Nevada Power of $12 million, $19 million and $45 million for the years ending December 31, 2015, 2014 and 2013, respectively. Nevada Power provided services to Sierra Pacific of $22 million, $20 million and $24 million for the years ended December 31, 2015, 2014 and 2013, respectively. Sierra Pacific provided services to Nevada Power of $16 million, $16 million and $22 million for the years ended December 31, 2015, 2014 and 2013, respectively. As of December 31, 2015 and 2014, Nevada Power's Consolidated Balance Sheets included amounts due to NV Energy of $40 million and $33 million, respectively. There were no receivables due from NV Energy as of December 31, 2015 and 2014. As of December 31, 2015 and 2014, Nevada Power's Consolidated Balance Sheets included receivables due from Sierra Pacific of $6 million and $5 million, respectively. There were no payables due to Sierra Pacific as of December 31, 2015 and 2014.

Certain disbursements for accounts payable and payroll are made by NV Energy on behalf of Nevada Power and reimbursed automatically when settled by the bank. These amounts are recorded as accounts payable at the time of disbursement.

(12) Retirement Plan and Postretirement Benefits

Nevada Power is a participant in benefit plans sponsored by NV Energy. The NV Energy Retirement Plan includes a qualified pension plan ("Qualified Pension Plan") and a supplemental executive retirement plan and a restoration plan (collectively, "Non-Qualified Pension Plans") that provide pension benefits for eligible employees. The NV Energy Comprehensive Welfare Benefit and Cafeteria Plan provides certain postretirement health care and life insurance benefits for eligible retirees ("Other Postretirement Plans") on behalf of Nevada Power. Nevada Power did not make any contributions to the Qualified Pension Plan, Non-Qualified Pension Plans or Other Postretirement Plans for the years ended December 31, 2015, 2014 and 2013. Amounts attributable to Nevada Power were allocated from NV Energy based upon the current, or in the case of retirees, previous, employment location. Offsetting regulatory assets and liabilities have been recorded related to the amounts not yet recognized as a component of net periodic benefit costs that will be included in regulated rates. Net periodic benefit costs not included in regulated rates are included in accumulated other comprehensive loss, net.

Amounts receivable from (payable to) NV Energy are included on the Consolidated Balance Sheets and consist of the following as of December 31(in millions):

	2015	2014
Qualified Pension Plan -		
Other long-term liabilities	$ (38)	$ (23)
Non-Qualified Pension Plans:		
Other current liabilities	(1)	(1)
Other long-term liabilities	(9)	(9)
Other Postretirement Plans -		
Other long-term liabilities	(5)	1

(13) Asset Retirement Obligations

Nevada Power 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.

Nevada Power 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 generation, 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. These accruals totaled $273 million and $295 million as of December 31, 2015 and 2014, respectively.

The following table presents Nevada Power's ARO liabilities by asset type as of December 31 (in millions):

	2015	2014
Waste water remediation	$ 42	$ 53
Evaporative ponds and dry ash landfills	27	25
Asbestos	3	3
Other	13	5
Total asset retirement obligations	$ 85	$ 86

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

	2015	2014
Beginning balance	$ 86	$ 100
Change in estimated costs	3	(18)
Additions	3	—
Retirements	(11)	—
Accretion	4	4
Ending balance	$ 85	$ 86
Reflected as:		
Other current liabilities	$ 13	$ 14
Other long-term liabilities	72	72
	$ 85	$ 86

In 2008, Nevada Power signed an administrative order of consent as owner and operator of Reid Gardner Generating Station Unit Nos. 1, 2 and 3 and as co-owner and operating agent of Unit No. 4. Based on the administrative order of consent, Nevada Power recorded estimated AROs and capital remediation costs. However, actual costs of work under the administrative order of consent may vary significantly once the scope of work is defined and additional site characterization has been completed. In connection with the termination of the co-ownership arrangement, effective October 22, 2013, between Nevada Power and California Department of Water Resources ("CDWR") for the Reid Gardner Generating Station Unit No. 4, Nevada Power and CDWR entered into a cost-sharing agreement that sets forth how the parties will jointly share in costs associated with all investigation, characterization and, if necessary, remedial activities as required under the administrative order of consent. The 2014 change in estimated costs was related to refinement of expected remediation costs at the Reid Gardner Generating Station and impacts of the new coal combustion rule.

Certain of Nevada Power's decommissioning and reclamation obligations relate to jointly-owned facilities, and as such, Nevada Power 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, the respective subsidiary may be obligated to absorb, directly or by paying additional sums to the entity, a proportionate share of the defaulting party's liability. Management has identified legal obligations to retire generation plant assets specified in land leases for Nevada Power's jointly-owned Navajo Generating Station and the Higgins Generating Station. Provisions of the lease require the lessees to remove the facilities upon request of the lessors at the expiration of the leases. Nevada Power's estimated share of the decommissioning and reclamation obligations are primarily recorded as ARO liabilities in other long-term liabilities on the Consolidated Balance Sheets.

The 2015 change in estimated costs is primarily due to changes in the amount and timing of cash flows related to the implementation of the United States Environmental Protection Agency's ("EPA") 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 was published in the Federal Register in April 2015 and was effective in October 2015. In addition to impacting existing AROs, the final rule also resulted in the recognition of additional AROs.

(14) Commitments and Contingencies

Environmental Laws and Regulations

Nevada Power 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 Nevada Power's current and future operations. Nevada Power believes it is in material compliance with all applicable laws and regulations.

In June 2013, the Nevada State Legislature passed Senate Bill No. 123 ("SB 123"), which included, in significant part:

- Accelerating the plan to retire 800 MWs of coal plants, starting as soon as December 31, 2014;
- Replacement of such coal plants by issuing requests for proposals for the procurement of 300 MWs from renewable facilities;
- Construction or acquisition and ownership of 50 MWs of electric generating capacity from renewable facilities;
- Construction or acquisition and ownership of 550 MWs of additional electric generating capacity; and
- Assuring regulatory procedures that protect reliability and supply and address financial impacts on customer and utility.

In May 2014, Nevada Power filed its Emissions Reduction Capacity Replacement Plan ("ERCR Plan") in compliance with SB 123. The filing proposed, among other items, the retirement of Reid Gardner Generating Station units 1, 2 and 3 in 2014 and unit 4 in 2017; the elimination of Nevada Power's ownership interest in Navajo Generating Station in 2019; and a plan to replace the generating capacity being retired, as required by SB 123. The ERCR Plan includes the issuance of requests for proposals for 300 MW of renewable energy to be issued between 2014 and 2016; the acquisition of a 272-MW natural gas co-generating facility in 2014; the acquisition of a 210-MW natural gas peaking facility in 2014; the construction of a 15-MW solar photovoltaic facility expected to be placed in-service in 2015; and the construction of a 200-MW solar photovoltaic facility expected to be placed in-service in 2016. In the second quarter of 2014, Nevada Power executed various contractual agreements to fulfill the proposed ERCR Plan, which are subject to the PUCN approval. The PUCN issued an order dated October 28, 2014 removing the 200-MW solar photovoltaic facility proposed by Nevada Power from the ERCR Plan but accepting the remaining requests. In November 2014, Nevada Power filed a petition for reconsideration, but in December 2014, the PUCN upheld the original order from October 2014 with respect to material matters. In December 2014, Nevada Power filed its acceptance of the modifications to the ERCR Plan.

In July 2015, Nevada Power filed an amendment to its Emissions Reduction and Capacity Replacement Plan ("ERCR Plan") with the PUCN. In September 2015, the PUCN approved the filed amendment requesting two renewable power purchase agreements with 100-MW solar photovoltaic generating facilities related to the replacement of coal plants. Each of these agreements were entered into by issuing requests for proposals for the procurement of energy through the competitive solicitation process that was set forth in Nevada Power's ERCR Plan in compliance with SB 123. In June 2015, the Nevada State Legislature passed Assembly Bill No. 498, which modified the capacity replacement components of SB 123. As a result, Nevada Power will not proceed with issuance of a third 100-MW request for proposal for renewable energy until such time as the PUCN determines Nevada Power has satisfactorily demonstrated a need for such electric generating capacity.

Reid Gardner Generation Station

In October 2011, Nevada Power received a request for information from the EPA Region 9 under Section 114 of the Clean Air Act requesting current and historical operations and capital project information for Nevada Power's Reid Gardner Generating Station located near Moapa, Nevada. The EPA's Section 114 information request does not allege any incidents of non-compliance at the plant, and there have been no other new enforcement-related proceedings that have been initiated by the EPA relating to the plant. Nevada Power completed its responses to the EPA during the first quarter of 2012 and will continue to monitor developments relating to this Section 114 request. At this time, Nevada Power cannot predict the impact, if any, associated with this information request.

Legal Matters

Nevada Power is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. Nevada Power does not believe that such normal and routine litigation will have a material impact on its consolidated financial results.

Commitments

Nevada Power has the following firm commitments that are not reflected on the Consolidated Balance Sheet. Minimum payments as of December 31, 2015 are as follows (in millions):

	2016	2017	2018	2019	2020	2021 and Thereafter	Total
Contract type:							
Fuel and capacity contract commitments	$ 612	$ 478	$ 330	$ 328	$ 330	$ 4,587	$ 6,665
Fuel and capacity contract commitments (not commercially operable)	—	20	23	23	30	603	699
Operating leases and easements	11	8	8	7	7	67	108
Maintenance, service and other contracts	46	116	38	37	35	109	381
Total commitments	$ 669	$ 622	$ 399	$ 395	$ 402	$ 5,366	$ 7,853

Fuel and Capacity Contract Commitments

Purchased Power

Nevada Power has several contracts for long-term purchase of electric energy which have been approved by the PUCN. The expiration of these contracts range from 2017 to 2040. Purchased power includes contracts which meet the definition of a lease. Nevada Power's rent expense for purchase power contracts which met the lease criteria for 2015, 2014 and 2013 were $264 million, $245 million and $400 million, respectively, and are recorded as cost of fuel, energy and capacity on the Consolidated Statements of Operations.

Coal and Natural Gas

Nevada Power has a contract for the transportation of coal that extends through 2017. Additionally, gas transportation contracts expire from 2016 to 2031 and the gas supply contract expires in 2017.

Fuel and Capacity Contract Commitments - Not Commercially Operable

Nevada Power has several contracts for long-term purchase of electric energy in which the facility remains under development. Amounts represent the estimated payments under renewable energy power purchase contracts, which have been approved by the PUCN and are contingent upon the developers obtaining commercial operation and their ability to deliver power.

Operating Leases and Easements

Nevada Power has non-cancelable operating leases primarily for office equipment, office space, certain operating facilities, vehicles and land. These leases generally require Nevada Power 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. Nevada Power also has non-cancelable easements for land. Rent expense on non-cancelable operating leases totaled $11 million, $10 million and $9 million for the years ended December 31, 2015, 2014 and 2013, respectively.

Maintenance, Service and Other Contracts

Nevada Power has long-term service agreements for the performance of maintenance on generation units. Obligation amounts are based on estimated usage. The estimated expiration of these service agreements range from 2020 to 2026.

(15) 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):

	2015	2014	2013
Supplemental disclosure of cash flow information -			
Interest paid, net of amounts capitalized	$ 186	$ 194	$ 209
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	$ 51	$ 30	$ 25
Capital and financial lease obligations incurred	$ (5)	$ 7	$ 419

(16) Unaudited Quarterly Operating Results (in millions)

	Three-Month Periods Ended			
	March 31, 2015	June 30, 2015	September 30, 2015	December 31, 2015
Operating revenues	$ 459	$ 607	$ 878	$ 458
Operating income	74	136	329	74
Net income	24	60	187	17

	Three-Month Periods Ended			
	March 31, 2014	June 30, 2014	September 30, 2014	December 31, 2014
Operating revenues	$ 417	$ 595	$ 867	$ 458
Operating income	55	145	307	34
Net income	6	62	168	(9)

Sierra Pacific Power Company and its subsidiaries
Consolidated Financial Section

Item 6. Selected Financial Data

Information required by Item 6 is omitted pursuant to General Instruction I(2)(a) to Form 10-K.

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

General

Sierra Pacific's revenues and operating income are subject to fluctuations during the year due to impacts that seasonal weather, rate changes, and customer usage patterns have on demand for electric energy, natural gas and resources. Sierra Pacific's electric segment is summer peaking experiencing its highest retail energy sales in response to the demand for air conditioning and its natural gas segment is winter peaking due to sales in response to the demand for heating. The variations in energy usage due to varying weather, customer growth and other energy usage patterns, including energy efficiency and conservation measures, necessitates a continual balancing of loads and resources and purchases and sales of energy under short- and long-term energy supply contracts. As a result, the prudent management and optimization of available resources has a direct effect on the operating and financial performance of Sierra Pacific. Additionally, the timely recovery of purchased power, fuel costs and other costs and the ability to earn a fair return on investments through rates are essential to the operating and financial performance of Sierra Pacific.

The following is management's discussion and analysis of certain significant factors that have affected the consolidated financial condition and results of operations of Sierra Pacific 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 Sierra Pacific's historical Consolidated Financial Statements and Notes to Consolidated Financial Statements in Item 8 of this Form 10-K. Sierra Pacific's actual results in the future could differ significantly from the historical results.

Results of Operations

Net income for the year ended December 31, 2015 was $83 million, a decrease of $4 million, or 5% compared to 2014. Net income decreased due to higher planned maintenance costs of $10 million, higher depreciation and amortization of $8 million as a result of higher regulatory amortizations and lower interest and dividend income of $8 million. The decrease in net income is offset by an increase in margin from recovery of costs associated with advanced service delivery of $9 million, lower impairment costs resulting from the settlement of the companion filing made in conjunction with Nevada Power's general rate case in 2014 of $8 million and a settlement payment associated with terminated transmission service of $4 million.

Net income for the year ended December 31, 2014 was $87 million, an increase of $32 million, or 58% compared to 2013. Net income increased primarily due to regulatory amortizations, $20 million in merger-related expenses in 2013, regulatory disallowances in 2013, lower maintenance costs at the generating stations, favorable other income (expense) related to interest and AFUDC, lower compensation costs, and a one-time bill credit of $5 million to retail customers recorded in 2013 in connection with the BHE Merger. The increase in net income was partially offset by $35 million in lower revenue as a result of reduced customer rates from the 2013 general rate case effective January 1, 2014 and $12 million in impairment charges related to recovery of certain assets not in rates.

Operating revenue; cost of fuel, energy and capacity; and natural gas purchased for resale are key drivers of Sierra Pacific's results of operations as they encompass retail and wholesale electricity and natural gas revenue and the direct costs associated with providing electricity and natural gas to customers. Sierra Pacific believes that a discussion of gross margin, representing operating revenue less cost of fuel, energy and capacity and natural gas purchased for resale, is therefore meaningful.

Electric Gross Margin

A comparison of Sierra Pacific's key operating results related to regulated electric gross margin for the years ended December 31 is as follows:

	2015	2014	Change		2014	2013	Change	
Gross margin (in millions):								
Operating electric revenue	$ 810	$ 779	$ 31	4 %	$ 779	$ 747	$ 32	4 %
Cost of fuel, energy and capacity	374	361	13	4	361	292	69	24
Gross margin	$ 436	$ 418	$ 18	4	$ 418	$ 455	$ (37)	(8)
GWh sold:								
Residential	2,315	2,268	47	2 %	2,268	2,370	(102)	(4)%
Commercial	2,942	2,944	(2)	—	2,944	2,948	(4)	—
Industrial	2,973	2,869	104	4	2,869	2,818	51	2
Other	16	16	—	—	16	16	—	—
Total retail	8,246	8,097	149	2	8,097	8,152	(55)	(1)
Wholesale	664	645	19	3	645	875	(230)	(26)
Total GWh sold	8,910	8,742	168	2	8,742	9,027	(285)	(3)
Average number of retail customers (in thousands):								
Residential	288	285	3	1 %	285	281	4	1 %
Commercial	46	46	—	—	46	46	—	—
Total	334	331	3	1	331	327	4	1
Average revenue per MWh:								
Retail	$ 90.85	$ 88.78	$ 2.07	2 %	$ 88.78	$ 83.54	$ 5.24	6 %
Wholesale	$ 61.37	$ 68.34	$ (6.97)	(10)%	$ 68.34	$ 50.99	$ 17.35	34 %
Heating degree days	4,122	3,910	212	5 %	3,910	5,008	(1,098)	(22)%
Cooling degree days	1,194	1,211	(17)	(1)%	1,211	1,177	34	3 %
Sources of energy (GWh)(1):								
Coal	1,210	1,870	(660)	(35)%	1,870	1,430	440	31 %
Natural gas	3,981	4,169	(188)	(5)	4,169	3,712	457	12
Total energy generated	5,191	6,039	(848)	(14)	6,039	5,142	897	17
Energy purchased	4,441	2,943	1,498	51	2,943	4,157	(1,214)	(29)
Total	9,632	8,982	650	7	8,982	9,299	(317)	(3)
Average cost of energy per MWh:								
Energy generated(2)	$ 41.60	$ 37.38	$ 4.22	11 %	$ 37.38	$ 27.81	$ 9.57	34 %
Energy purchased	$ 35.54	$ 45.95	$ (10.41)	(23)%	$ 45.95	$ 35.83	$ 10.12	28 %

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

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

Natural Gas Gross Margin

A comparison of key results related to regulated natural gas gross margin for the years ended December 31 is as follows:

	2015	2014	Change		2014	2013	Change	
Gross margin (in millions):								
Operating natural gas revenue	$ 137	$ 125	$ 12	10%	$ 125	$ 106	$ 19	18 %
Natural gas purchased for resale	84	76	8	11	76	56	20	36
Gross margin	$ 53	$ 49	$ 4	8	$ 49	$ 50	$ (1)	(2)
Dth sold:								
Residential	8,649	7,921	728	9%	7,921	9,791	(1,870)	(19)%
Commercial	4,198	3,921	277	7	3,921	4,604	(683)	(15)
Industrial	1,470	1,416	54	4	1,416	1,488	(72)	(5)
Total retail	14,317	13,258	1,059	8	13,258	15,883	(2,625)	(17)
Average number of retail customers (in thousands)	159	156	3	2%	156	155	1	1 %
Average revenue per retail Dth sold:	$ 9.57	$ 9.43	$ 0.14	1%	$ 9.43	$ 6.67	$ 2.76	41 %
Average cost of natural gas per retail Dth sold	$ 5.87	$ 5.73	$ 0.14	2%	$ 5.73	$ 3.53	$ 2.20	62 %
Heating degree days	4,122	3,910	212	5%	3,910	5,008	(1,098)	(22)%

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

Electric gross margin increased $18 million, or 4%, for 2015 compared to 2014 due to:

- $9 million from recovery of costs associated with advanced service delivery;
- $5 million in higher energy efficiency program rate revenue, which is offset in operating and maintenance expense; and
- $4 million related to a settlement payment associated with terminated transmission service.

Natural gas gross margin increased $4 million, or 8%, for 2015 compared to 2014 due to recovery of costs associated with advanced service delivery and an increase in customer usage in 2015, primarily due to the impacts of weather.

Operating and maintenance increased $5 million, or 3%, for 2015 compared to 2014 due to increased planned maintenance costs, higher energy efficiency program costs, which are fully recovered in operating revenue, and higher ON Line lease expense. This increase was partially offset by lower impairment costs resulting from the settlement of the companion filing made in conjunction with Nevada Power's general rate case in 2014, lower costs related to relinquishing an insurance claim in 2014 for a previously sold asset and decreased compensation costs.

Depreciation and amortization increased $8 million, or 8%, for 2015 compared to 2014 primarily due to regulatory amortizations associated with advanced service delivery.

Property and other taxes increased $3 million, or 12%, for 2015 compared to 2014 due to an increase in property tax assessed values, higher franchise taxes and a new state commerce tax.

Other income (expense) is unfavorable $10 million, or 23%, for 2015 compared to 2014 primarily due to lower carrying charges related to the recovery of costs associated with advanced service delivery approved in the companion filing of the 2014 Nevada Power general rate case effective January 2015.

Income tax expense remained constant, for 2015 compared to 2014. The effective tax rate was 36% for 2015 and 35% for 2014. The decrease in the effective tax rate is primarily due to an increase in the effects of ratemaking.

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

Electric gross margin decreased $37 million, or 8%, for 2014 compared to 2013 primarily due to:

- $35 million in lower revenue in 2014 as a result of reduced customer rates from the 2013 general rate case effective January 1, 2014;
- $8 million lower net usage primarily due to a decrease in heating degree days; and
- $2 million in lower energy efficiency program rate revenue, which is offset in operating and maintenance expense.

The decrease was partially offset by:

- $5 million one-time bill credit to retail customers in connection with the BHE Merger in 2013 and
- $3 million due to customer growth.

Operating and maintenance decreased $39 million, or 20%, for 2014 compared to 2013 primarily due to $11 million in regulatory disallowances in 2013; lower maintenance costs at the generating stations; regulatory amortizations; lower compensation costs; and lower energy efficiency program costs, which are fully recovered in operating revenue. The decrease was partially offset by $12 million in impairment charges related to recovery of certain assets not in rates.

Depreciation and amortization decreased $18 million, or 15%, for 2014 compared to 2013 primarily due to regulatory amortizations.

Property and other taxes increased $1 million, or 4%, for 2014 compared to 2013 primarily due to an increase in property tax assessed values.

Sierra Pacific incurred costs totaling $20 million in 2013 related to the BHE Merger, consisting of amounts payable under NV Energy's change in control policy of $6 million, accelerated vesting and stock compensation under NV Energy's long-term incentive plan of $7 million, investment banker fees of $6 million and legal and other expenses of $1 million.

Other income (expense) is favorable $8 million, or 15%, for 2014 compared to 2013 primarily due to an increase in interest income on regulatory assets, decreased interest expense as a result of using the proceeds from issuing lower cost debt in August 2013 to repay higher cost debt and an increase in AFUDC from an increase in construction activity.

Income tax expense increased $14 million, or 42%, for 2014 compared to 2013 due to higher income before income tax expense, partially offset by a decrease in the effective tax rate. The effective tax rate was 35% for 2014 and 37% for 2013. The decrease in the effective tax rate is primarily due to certain non-deductible merger related costs in 2013.

Liquidity and Capital Resources

As of December 31, 2015, Sierra Pacific's total net liquidity was $356 million as follows (in millions):

Cash and cash equivalents	$ 106
Credit facilities[1]	250
Less:	
Short-term debt	—
Letters of credit and tax exempt bond support	—
Net credit facilities	250
Total net liquidity	$ 356
Credit facilities:	
Maturity dates	March 2018

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

Operating Activities

Net cash flows from operating activities for the years ended December 31, 2015 and 2014 were $342 million and $246 million, respectively. The change was due to deferred energy from lower fuel costs and higher collections, lower purchased power payments, timing of projects under long-term service agreements which are offset in investing activities, a payment in 2014 of the bill credit to customers as a result of the BHE Merger and a settlement payment associated with terminated transmission service. The increase was offset by higher refunds to customers for renewable energy programs and lower collections from customers due to usage and weather.

Net cash flows from operating activities for the years ended December 31, 2014 and 2013 were $246 million and $226 million, respectively. The change was primarily due to lower deferred energy refunded to customers, funding of retirement plans in 2013, BHE Merger costs and lower compensation payments. These increases were partially offset by lower collections from customers for conservation and renewable programs, lower coal purchases in 2013 and lower collections of energy costs as a result of adjustments to base tariff energy rates.

The timing of Sierra Pacific's income tax cash flows from period to period can be significantly affected by the estimated federal income tax payment methods and assumptions for each payment date.

In December 2015, the Protecting Americans from Tax Hikes Act of 2015 ("PATH") was signed into law, extending bonus depreciation for qualifying property acquired and placed in-service before January 1, 2020 (bonus depreciation rates will be 50% for 2015-2017, 40% in 2018, and 30% in 2019), with an additional year for certain longer lived assets. Investment tax credits were extended and phased-down for solar projects that are under construction before the end of 2021 (investment tax credit rates are 30% through 2019, 26% in 2020 and 22% in 2021; they revert to the statutory rate of 10% thereafter). As a result of PATH, Sierra Pacific's cash flows from operations are expected to benefit in 2016 and beyond due to bonus depreciation on qualifying assets placed in-service and investment tax credits (once the net operating loss is fully utilized) earned on qualifying projects.

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, Sierra Pacific'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, 2015 and 2014 were $(250) million and $(186) million, respectively. The change was primarily due to an increase in capital expenditures relating to Tracy and Valmy Generating Stations including timing of projects under long-term service agreements which are offset in operating activities and the purchase of the general office building in Reno, Nevada.

Net cash flows from investing activities for the years ended December 31, 2014 and 2013 were $(186) million and $(139) million, respectively. The change was primarily due to higher capital expenditures for emission control equipment at the Valmy, Ft. Churchill and Tracy Generating Stations.

Financing Activities

Net cash flows from financing activities for the years ended December 31, 2015 and 2014 were $(8) million and $(105) million, respectively. The change was due to lower dividends paid to NV Energy.

Net cash flows from financing activities for the years ended December 31, 2014 and 2013 were $(105) million and $(81) million, respectively. The change was primarily due to higher dividends paid to NV Energy.

Ability to Issue Debt

Sierra Pacific's ability to issue debt is primarily impacted by its financing authority from the PUCN. As of December 31, 2015, Sierra Pacific has financing authority from the PUCN consisting of the ability to: (1) issue additional long-term debt securities of up to $350 million; (2) refinance up to $348 million of long-term debt securities; and (3) maintain a revolving credit facility of up to $600 million. Sierra Pacific's revolving credit facility contains a financial maintenance covenant which Sierra Pacific was in compliance with as of December 31, 2015. In addition, certain financing agreements contain covenants which are currently suspended as Sierra Pacific's senior secured debt is rated investment grade. However, if Sierra Pacific's senior secured debt ratings fall below investment grade by either Moody's Investor Service or Standard & Poor's, Sierra Pacific would be subject to limitations under these covenants.

Ability to Issue General and Refunding Mortgage Securities

To the extent Sierra Pacific has the ability to issue debt under the most restrictive covenants in its financing agreements and has financing authority to do so from the PUCN, Sierra Pacific's ability to issue secured debt is limited by the amount of bondable property or retired bonds that can be used to issue debt under Sierra Pacific's indenture. Sierra Pacific's indenture creates a lien on substantially all of Sierra Pacific's properties in Nevada. As of December 31, 2015, $3.7 billion of Sierra Pacific's assets were pledged. Sierra Pacific had the capacity to issue $1.1 billion of additional general and refunding mortgage securities as of December 31, 2015 determined on the basis of 70% of net utility property additions. Property additions include plant-in-service and specific assets in construction work-in-progress. The amount of bond capacity listed above does not include eligible property in construction work-in-progress. Sierra Pacific also has the ability to release property from the lien of Sierra Pacific's indenture on the basis of net property additions, cash or retired bonds. To the extent Sierra Pacific releases property from the lien of Sierra Pacific's indenture, it will reduce the amount of securities issuable under the indenture.

Future Uses of Cash

Capital Expenditures

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 and associated operating costs are generally incorporated into Sierra Pacific's regulated retail rates. Expenditures for certain assets may ultimately include acquisition of existing assets.

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

	Historical			**Forecasted**		
	2013	**2014**	**2015**	**2016**	**2017**	**2018**
Generation development	$ 48	$ 51	$ —	$ —	$ —	$ 1
Distribution	63	89	86	105	72	66
Transmission system investment	7	19	38	50	43	26
Other	21	27	126	59	34	30
Total	$ 139	$ 186	$ 250	$ 214	$ 149	$ 123

Sierra Pacific’s forecast capital expenditures include investments that relate to operating projects that consist of routine expenditures for transmission, distribution, generation and other infrastructure needed to serve existing and expected demand.

Long-Term Debt Maturity

Sierra Pacific has $450 million of its 6% Series M general and refunding mortgage securities maturing in May 2016 and plans to use existing cash, issue additional long-term debt or utilize other sources to fund the maturing securities.

Contractual Obligations

Sierra Pacific has contractual cash obligations that may affect its consolidated financial condition. The following table summarizes Sierra Pacific's material contractual cash obligations as of December 31, 2015 (in millions):

	Payments Due by Periods				
	2016	2017 - 2018	2019 - 2020	2021 and Thereafter	Total
Long-term debt	$ 450	$ —	$ —	$ 716	$ 1,166
Interest payments on long-term debt(1)	41	55	55	339	490
Capital leases, including interest(2)	4	3	2	11	20
ON Line financial lease, including interest(2)	2	4	5	43	54
Fuel and capacity contract commitments(1)	207	268	163	444	1,082
Operating leases and easements(1)	6	7	6	65	84
Asset retirement obligations	—	—	—	14	14
Maintenance, service and other contracts(1)	5	8	10	22	45
Total contractual cash obligations	$ 715	$ 345	$ 241	$ 1,654	$ 2,955

(1) Not reflected on the Consolidated Balance Sheets.

(2) Interest is not reflected on the Consolidated Balance Sheets.

Sierra Pacific has other types of commitments that arise primarily from unused lines of credit, letters of credit or relate to construction and other development costs (Liquidity and Capital Resources included within this Item 7 and Note 6) and uncertain tax positions (Note 9), which have not been included in the above table because the amount and timing of the cash payments are not certain. Refer, where applicable, to the respective referenced note in Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information.

Regulatory Matters

Sierra Pacific is subject to comprehensive regulation. Refer to the discussion contained in Item 1 of this Form 10-K for further discussion regarding Sierra Pacific's general regulatory framework and current regulatory matters.

Environmental Laws and Regulations

Sierra Pacific 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 Sierra Pacific'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. Sierra Pacific 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. Environmental laws and regulations continue to evolve, and Sierra Pacific is unable to predict the impact of the changing laws and regulations on its operations and financial results. Refer to "Liquidity and Capital Resources" for discussion of Sierra Pacific's forecasted environmental-related capital expenditures.

Refer to "Environmental Laws and Regulations" in Item 1 of this Form 10-K for additional information regarding environmental laws and regulations and "Liquidity and Capital Resources" for Sierra Pacific's forecasted environmental-related capital expenditures.

Collateral and Contingent Features

Debt of Sierra Pacific is rated by credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of Sierra Pacific's ability to, in general, meet the obligations of its issued debt. 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.

Sierra Pacific 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. Sierra Pacific's secured revolving credit facility does not require the maintenance of a minimum credit rating level in order to draw upon its availability. However, commitment fees and interest rates under the credit facility 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.

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 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," or in some cases terminate the contract, in the event of a material adverse change in creditworthiness. These rights can vary by contract and by counterparty. As of December 31, 2015, the applicable credit ratings from the three recognized credit rating agencies were investment grade. If all credit-risk-related contingent features or adequate assurance provisions for these agreements had been triggered as of December 31, 2015, Sierra Pacific would have been required to post $13 million of additional collateral. Sierra Pacific's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation, or other factors.

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.

Sierra Pacific 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 Sierra Pacific. 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. Sierra Pacific qualifies or believes it will qualify for many of these exemptions. Sierra Pacific 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 Sierra Pacific or could have impacts to energy and other markets in general that could have an impact on Sierra Pacific's consolidated financial results.

Inflation

Historically, overall inflation and changing prices in the economies where Sierra Pacific operates has not had a significant impact on Sierra Pacific's consolidated financial results. Sierra Pacific operates under a cost-of-service based rate structure administered by the PUCN and the FERC. Under this rate structure, Sierra Pacific is allowed to include prudent costs in its rates, including the impact of inflation after Sierra Pacific experiences cost increases. Fuel and purchase power costs are recovered through a balancing account, minimizing the impact of inflation related to these costs. Sierra Pacific attempts to minimize the potential impact of inflation on its operations through the use of periodic rate adjustments for fuel and energy costs, 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.

New Accounting Pronouncements

For a discussion of new accounting pronouncements affecting Sierra Pacific, 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 Sierra Pacific's methods, judgments and assumptions used in the preparation of the Consolidated Financial Statements and should be read in conjunction with Sierra Pacific's Summary of Significant Accounting Policies included in Sierra Pacific's 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

Sierra Pacific prepares its Consolidated Financial Statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, Sierra Pacific 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 regulated 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 regulated rates occur.

Sierra Pacific continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future regulated 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 Sierra Pacific's ability to recover its costs. Sierra Pacific believes the application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in future regulated 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 regulated rates, the related regulatory assets and liabilities will be written off to net income, returned to customers or re-established as accumulated other comprehensive income (loss). Total regulatory assets were $432 million and total regulatory liabilities were $308 million as of December 31, 2015. Refer to Sierra Pacific's Note 5 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding Sierra Pacific's regulatory assets and liabilities.

Impairment of Long-Lived Assets

Sierra Pacific evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As substantially all property, plant and equipment was used in regulated businesses as of December 31, 2015, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

The estimate of cash flows arising from the future use of the asset that are used in the impairment analysis requires judgment regarding what Sierra Pacific would expect to recover from the future use of the asset. Changes in judgment that could significantly alter the calculation of the fair value or the recoverable amount of the asset may result from significant changes in the regulatory environment, the business climate, management's plans, legal factors, market price of the asset, the use of the asset or the physical condition of the asset, future market prices, load growth, competition and many other factors over the life of the asset. Any resulting impairment loss is highly dependent on the underlying assumptions and could significantly affect Sierra Pacific's results of operations.

Income Taxes

In determining Sierra Pacific's income taxes, management is required to interpret complex income tax laws and regulations, which includes consideration of regulatory implications imposed by Sierra Pacific's various regulatory jurisdictions. Sierra Pacific'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. Sierra Pacific 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 Sierra Pacific's federal, state and local income tax examinations is uncertain, Sierra Pacific 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 Sierra Pacific's consolidated financial results. 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. Refer to Sierra Pacific's Note 9 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding Sierra Pacific's income taxes.

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 Sierra Pacific is required to pass on to its customers are charged or credited directly to a regulatory asset or liability. As of December 31, 2015, these amounts were recognized as regulatory assets of $90 million and regulatory liabilities of $7 million, and will be included in regulated rates when the temporary differences reverse.

Revenue Recognition - Unbilled Revenue

Revenue is recognized as electricity or natural gas 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 their last billing is estimated, and the corresponding unbilled revenue is recorded. Unbilled revenue was $59 million as of December 31, 2015. 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

Sierra Pacific's Consolidated Balance Sheets include assets and liabilities with fair values that are subject to market risks. Sierra Pacific's significant market risks are primarily associated with commodity prices, interest rates and the extension of credit to counterparties with which Sierra Pacific transacts. The following discussion addresses the significant market risks associated with Sierra Pacific's business activities. Sierra Pacific has established guidelines for credit risk management. Refer to Note 2 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding Sierra Pacific's contracts accounted for as derivatives.

Commodity Price Risk

Sierra Pacific is exposed to the impact of market fluctuations in commodity prices and interest rates. Sierra Pacific is principally exposed to electricity, natural gas and coal market fluctuations primarily through Sierra Pacific's obligation to serve retail customer load in its regulated service territory. Sierra Pacific'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, wholesale electricity that is purchased and sold, and natural gas supply for retail customers. 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. The actual cost of fuel and purchased power is recoverable through the deferred energy mechanism. Interest rate risk exists on variable-rate debt and future debt issuances. Sierra Pacific does not engage in proprietary trading activities. To mitigate a portion of its commodity price risk, Sierra Pacific uses commodity derivative contracts, which may include forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. Sierra Pacific does not hedge its commodity price risk, thereby exposing the unhedged portion to changes in market prices. Sierra Pacific's exposure to commodity price risk is generally limited by its ability to include commodity costs in regulated rates through its deferred energy mechanism, which is subject to disallowance and regulatory lag that occurs between the time the costs are incurred and when the costs are included in regulated rates, as well as the impact of any customer sharing resulting from cost adjustment mechanisms.

Interest Rate Risk

Sierra Pacific is exposed to interest rate risk on its outstanding variable-rate short- and long-term debt and future debt issuances. Sierra Pacific 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, Sierra Pacific's fixed-rate long-term debt does not expose Sierra Pacific 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 Sierra Pacific were to reacquire all or a portion of these instruments prior to their maturity. The nature and amount of Sierra Pacific'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 and 7 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional discussion of Sierra Pacific's short- and long-term debt.

As of December 31, 2015 and 2014, Sierra Pacific had short- and long-term variable-rate obligations totaling $214 million that expose Sierra Pacific to the risk of increased interest expense in the event of increases in short-term interest rates. If variable interest rates were to increase by 10% from December 31 levels, it would not have a material effect on Sierra Pacific's consolidated annual interest expense. The carrying value of the variable-rate obligations approximates fair value as of December 31, 2015 and 2014.

Credit Risk

Sierra Pacific 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 Sierra Pacific's counterparties have similar economic, industry or other characteristics and due to direct and indirect relationships among the counterparties. Before entering into a transaction, Sierra Pacific 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, Sierra Pacific enters into netting and collateral arrangements that may include margining and cross-product netting agreements and obtain third-party guarantees, letters of credit and cash deposits. If required, Sierra Pacific exercises rights under these arrangements, including calling on the counterparty's credit support arrangement.

As of December 31, 2015, Sierra Pacific's aggregate credit exposure from energy related transactions were not material, based on settlement and mark-to-market exposures, net of collateral.

Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Sierra Pacific Power Company
Las Vegas, Nevada

We have audited the accompanying consolidated balance sheets of Sierra Pacific Power Company and subsidiaries ("Sierra Pacific") as of December 31, 2015 and 2014, and the related consolidated statements of operations, changes in shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2015. These financial statements are the responsibility of Sierra Pacific's management. Our responsibility is to express an opinion on the 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. Sierra Pacific 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 Sierra Pacific'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 Sierra Pacific Power Company and subsidiaries as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Las Vegas, Nevada
February 26, 2016

SIERRA PACIFIC POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions, except share data)

	As of December 31,	
	2015	**2014**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 106	$ 22
Accounts receivable, net	124	127
Inventories	39	40
Regulatory assets	—	32
Other current assets	13	20
Total current assets	282	241
Property, plant and equipment, net	2,766	2,640
Regulatory assets	432	444
Other assets	7	11
Total assets	$ 3,487	$ 3,336
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Accounts payable	$ 127	$ 127
Accrued interest	15	15
Accrued property, income and other taxes	13	12
Regulatory liabilities	78	39
Current portion of long-term debt and financial and capital lease obligations	453	1
Customer deposits	17	16
Other current liabilities	11	14
Total current liabilities	714	224
Long-term debt and financial and capital lease obligations	749	1,189
Regulatory liabilities	230	262
Deferred income taxes	570	524
Other long-term liabilities	148	139
Total liabilities	2,411	2,338
Commitments and contingencies (Note 13)		
Shareholder's equity:		
Common stock - $3.75 stated value, 20,000,000 shares authorized and 1,000 issued and outstanding	—	—
Other paid-in capital	1,111	1,111
Accumulated deficit	(35)	(111)
Accumulated other comprehensive loss, net	—	(2)
Total shareholder's equity	1,076	998
Total liabilities and shareholder's equity	$ 3,487	$ 3,336

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

SIERRA PACIFIC POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2015	2014	2013
Operating revenue:			
Electric	$ 810	$ 779	$ 747
Natural gas	137	125	106
Total operating revenue	947	904	853
Operating costs and expenses:			
Cost of fuel, energy and capacity	374	361	292
Natural gas purchased for resale	84	76	56
Operating and maintenance	163	158	197
Depreciation and amortization	113	105	123
Property and other taxes	29	26	25
Merger-related	—	—	20
Total operating costs and expenses	763	726	713
Operating income	184	178	140
Other income (expense):			
Interest expense	(61)	(61)	(61)
Allowance for borrowed funds	2	2	1
Allowance for equity funds	2	3	2
Other, net	3	12	6
Total other income (expense)	(54)	(44)	(52)
Income before income tax expense	130	134	88
Income tax expense	47	47	33
Net income	$ 83	$ 87	$ 55

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

SIERRA PACIFIC POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY
(Amounts in millions, except shares)

	Common Stock		Other Paid-in Capital	Accumulated Deficit	Accumulated Other Comprehensive Loss, Net	Total Shareholder's Equity
	Shares	Amount				
Balance, December 31, 2012	1,000	$ —	$ 1,111	$ (71)	$ (1)	$ 1,039
Net income	—	—	—	55	—	55
Dividends declared	—	—	—	(77)	—	(77)
Other	—	—	—	—	(1)	(1)
Balance, December 31, 2013	1,000	—	1,111	(93)	(2)	1,016
Net income	—	—	—	87	—	87
Dividends declared	—	—	—	(105)	—	(105)
Balance, December 31, 2014	1,000	—	1,111	(111)	(2)	998
Net income	—	—	—	83	—	83
Dividends declared	—	—	—	(7)	—	(7)
Other	—	—	—	—	2	2
Balance, December 31, 2015	1,000	$ —	$ 1,111	$ (35)	$ —	$ 1,076

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

SIERRA PACIFIC POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31,		
	2015	**2014**	**2013**
Cash flows from operating activities:			
Net income	$ 83	$ 87	$ 55
Adjustments to reconcile net income to net cash from operating activities:			
Loss on nonrecurring items	—	14	—
Depreciation and amortization	113	105	123
Allowance for equity funds	(2)	(3)	(2)
Deferred income taxes and amortization of investment tax credits	47	47	36
Changes in regulatory assets and liabilities	(21)	(23)	74
Deferred energy	81	(30)	(24)
Amortization of deferred energy	17	19	(43)
Other, net	(9)	20	14
Changes in other operating assets and liabilities:			
Accounts receivable and other assets	15	28	(8)
Inventories	1	3	17
Accounts payable and other liabilities	17	(21)	(16)
Net cash flows from operating activities	342	246	226
Cash flows from investing activities:			
Capital expenditures	(252)	(186)	(139)
Other, net	2	—	—
Net cash flows from investing activities	(250)	(186)	(139)
Cash flows from financing activities:			
Proceeds from issuance of long-term debt, net of costs	—	—	247
Repayments of long-term debt and financial and capital lease obligations	(1)	1	(251)
Dividends paid	(7)	(105)	(77)
Other, net	—	(1)	—
Net cash flows from financing activities	(8)	(105)	(81)
Net change in cash and cash equivalents	84	(45)	6
Cash and cash equivalents at beginning of period	22	67	61
Cash and cash equivalents at end of period	$ 106	$ 22	$ 67

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

(1) Organization and Operations

Sierra Pacific Power Company, together with its subsidiaries ("Sierra Pacific"), is a wholly owned subsidiary of NV Energy, Inc. ("NV Energy"), a holding company that also owns Nevada Power Company ("Nevada Power") and certain other subsidiaries. Sierra Pacific is a United States regulated electric utility company serving retail customers, including residential, commercial and industrial customers and regulated retail natural gas customers primarily in northern Nevada. NV Energy is an indirect wholly owned subsidiary of Berkshire Hathaway Energy Company ("BHE"). BHE is 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 Sierra Pacific 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; recovery of long-lived assets; 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

Sierra Pacific prepares its Consolidated Financial Statements in accordance with authoritative guidance for regulated operations, which recognizes the economic effects of regulation. Accordingly, Sierra Pacific 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 regulated 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 regulated rates occur.

Sierra Pacific continually evaluates the applicability of the guidance for regulated operations and whether its regulatory assets and liabilities are probable of inclusion in future regulated 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 Sierra Pacific's ability to recover its costs. Sierra Pacific believes the application of the guidance for regulated operations is appropriate and its existing regulatory assets and liabilities are probable of inclusion in future regulated 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 regulated rates, the related regulatory assets and liabilities will be written off to net income, returned to customers or re-established as accumulated other comprehensive income (loss).

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 assets on the Consolidated Balance Sheets.

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 Sierra Pacific's assessment of the collectibility of amounts owed to Sierra Pacific by its customers. This assessment requires judgment regarding the ability of customers to pay or the outcome of any pending disputes. Sierra Pacific also has the ability to assess deposits on customers who have delayed payments or who are deemed to be a credit risk. 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):

	2015	2014	2013
Beginning balance	$ 2	$ 1	$ 1
Charged to operating costs and expenses, net	1	2	2
Write-offs, net	(2)	(1)	(2)
Ending balance	$ 1	$ 2	$ 1

Derivatives

Sierra Pacific employs a number of different derivative contracts, which may include forwards, futures, options, swaps and other agreements, to manage its commodity price 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 cost of fuel, energy and capacity or natural gas purchased for resale on the Consolidated Statements of Operations.

For Sierra Pacific's derivatives not designated as hedging contracts, the settled amount is generally included in regulated 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 regulated rates are recorded as regulatory assets and liabilities.

Inventories

Inventories consist mainly of materials and supplies totaling $34 million and $32 million as of December 31, 2015 and 2014, respectively, and fuel, which includes coal stock, stored natural gas and fuel oil, totaling $5 million and $8 million as of December 31, 2015 and 2014, respectively. The cost is determined using the average cost method. Materials are charged to inventory when purchased and are expensed or capitalized to construction work in process, as appropriate, when used. Fuel costs are recovered from retail customers through the base tariff energy rates and deferred energy accounting adjustment charges approved by the Public Utilities Commission of Nevada ("PUCN").

Property, Plant and Equipment, Net

General

Additions to property, plant and equipment are recorded at cost. Sierra Pacific capitalizes all construction-related material, direct labor and contract services, as well as indirect construction costs. Indirect construction costs include debt allowance for funds used during construction ("AFUDC"), and equity AFUDC, as applicable. 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. The cost of repairs and minor replacements are charged to expense when incurred with the exception of costs for generation plant maintenance under certain long-term service agreements. Costs under these agreements are expensed straight-line over the term of the agreements as approved by the PUCN.

Depreciation and amortization are generally computed by applying the composite or straight-line method based on either estimated useful lives or mandated recovery periods as prescribed by Sierra Pacific's various regulatory authorities. Depreciation studies are completed by Sierra Pacific to determine the appropriate group lives, net salvage and group depreciation rates. These studies are reviewed and rates are ultimately approved by the applicable regulatory commission. 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 a cost of removal regulatory liability on the Consolidated Balance Sheets. As actual removal costs are incurred, the associated liability is reduced.

Generally when Sierra Pacific 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 regulated facilities, are capitalized as a component of property, plant and equipment, with offsetting credits to the Consolidated Statements of Operations. The rate applied to construction costs is the lower of the PUCN allowed rate of return and rates computed based on guidelines set forth by the Federal Energy Regulatory Commission ("FERC"). After construction is completed, Sierra Pacific 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. Sierra Pacific's AFUDC rate used during 2015 and 2014 was 7.62% and 7.58% for electric, 5.97% and 4.96% for natural gas and 7.44% and 7.28% for common facilities, respectively.

Asset Retirement Obligations

Sierra Pacific recognizes AROs when it has a legal obligation to perform decommissioning, reclamation or removal activities upon retirement of an asset. Sierra Pacific'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 on the Consolidated Balance Sheets.

Management's methodology to assess its legal obligation includes an inventory of assets by Sierra Pacific's system and components and a review of rights-of-way and easements, regulatory orders, leases and federal, state and local environmental laws. Additionally, management has determined evaporative ponds, dry ash landfills, fuel storage tanks, asbestos and oils treated with Poly Chlorinated Biphenyl have met the requirements for an ARO.

Impairment of Long-Lived Assets

Sierra Pacific evaluates long-lived assets for impairment, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable or the assets are being held for sale. Upon the occurrence of a triggering event, the asset is reviewed to assess whether the estimated undiscounted cash flows expected from the use of the asset plus the residual value from the ultimate disposal exceeds the carrying value of the asset. If the carrying value exceeds the estimated recoverable amounts, the asset is written down to the estimated fair value and any resulting impairment loss is reflected on the Consolidated Statements of Operations. As substantially all property, plant and equipment was used in regulated businesses as of December 31, 2015, the impacts of regulation are considered when evaluating the carrying value of regulated assets.

Income Taxes

Berkshire Hathaway includes Sierra Pacific in its United States federal income tax return. Consistent with established regulatory practice, Sierra Pacific's provision for income taxes has been computed on a separate return 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 other comprehensive income ("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 Sierra Pacific is required to pass on to its customers are charged or credited directly to a regulatory asset or liability. As of December 31, 2015 and 2014, these amounts were recognized as regulatory assets of $90 million and $94 million, respectively, and regulatory liabilities of $7 million and $8 million, respectively, and will be included in regulated 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.

In determining Sierra Pacific's income taxes, management is required to interpret complex income tax laws and regulations, which includes consideration of regulatory implications imposed by Sierra Pacific's various regulatory jurisdictions. Sierra Pacific'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. Sierra Pacific 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 Sierra Pacific's federal, state and local income tax examinations is uncertain, Sierra Pacific 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 Sierra Pacific's consolidated financial results. 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.

Revenue Recognition

Revenue is recognized as electricity or natural gas is delivered or services are provided. Revenue recognized includes billed and unbilled amounts. As of December 31, 2015 and 2014, unbilled revenue was $59 million and $57 million, respectively, and is included in accounts receivable, net on the Consolidated Balance Sheets. Rates are established by regulators or contractual arrangements. When preliminary rates are permitted to be billed prior to final approval by the applicable regulator, certain revenue collected may be subject to refund and a liability for estimated refunds is accrued. Sierra Pacific 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.

Sierra Pacific primarily buys energy and natural gas to satisfy its customer load requirements. Due to changes in retail customer load requirements, Sierra Pacific may not take physical delivery of the energy or natural gas. Sierra Pacific may sell the excess energy or natural gas to the wholesale market. In such instances, it is Sierra Pacific's policy allocate the natural gas sales between generation and natural gas retail. The energy sales and natural gas sales allocated to generation are recorded net in cost of fuel, energy and capacity. The natural gas sales allocated to natural gas retail is recorded as wholesale revenue.

Unamortized Debt Premiums, Discounts and Issuance Costs

Premiums, discounts and financing costs incurred for the issuance of long-term debt are amortized over the term of the related financing using the effective interest method.

New Accounting Pronouncements

In November 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2015-17, which amends FASB Accounting Standards Codification ("ASC") Topic 740, "Income Taxes". The amendments in this guidance require that deferred income tax liabilities and assets be classified as noncurrent in the balance sheet. This guidance is effective for interim and annual reporting periods beginning after December 15, 2016, with early adoption permitted, and may be adopted prospectively or retrospectively for each period presented to reflect the new guidance. Sierra Pacific early adopted this guidance as of December 31, 2015 under a retrospective method, resulting in decreases in current deferred income tax assets and noncurrent deferred income tax liabilities of $42 million as of December 31, 2014.

In April 2015, the FASB issued ASU No. 2015-03, which amends FASB ASC Subtopic 835-30, "Interest - Imputation of Interest." The amendments in this guidance require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability instead of as an asset. This guidance is effective for interim and annual reporting periods beginning after December 15, 2015, with early adoption permitted. This guidance must be adopted retrospectively, wherein the balance sheet of each period presented should be adjusted to reflect the new guidance. Sierra Pacific early adopted this guidance as of December 31, 2015 under a retrospective method, resulting in a decrease in other assets and long-term debt of $10 million as of December 31, 2014.

In May 2014, the FASB issued ASU No. 2014-09, which creates FASB 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. In August 2015, the FASB issued ASU No. 2015-14, which defers the effective date of ASU No. 2014-09 one year to interim and annual reporting periods beginning after December 15, 2017. This guidance may be adopted retrospectively or under a modified retrospective method where the cumulative effect is recognized at the date of initial application. Sierra Pacific is currently evaluating the impact of adopting this guidance on its Consolidated Financial Statements and 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	2015	2014
Utility plant:			
Electric generation	40 - 125 years	$ 1,134	$ 1,036
Electric distribution	20 - 70 years	1,382	1,321
Electric transmission	50 - 70 years	739	719
Electric general and intangible plant	5 - 65 years	139	123
Natural gas distribution	40 - 70 years	374	366
Natural gas general and intangible plant	8 - 10 years	13	13
Common general	5 - 65 years	265	234
Utility plant		4,046	3,812
Accumulated depreciation and amortization		(1,368)	(1,300)
Utility plant, net		2,678	2,512
Construction work-in-progress		88	128
Property, plant and equipment, net		$ 2,766	$ 2,640

All of Sierra Pacific's plant is subject to the ratemaking jurisdiction of the PUCN and the FERC. Sierra Pacific's depreciation and amortization expense, as authorized by the PUCN, stated as a percentage of the depreciable property balances as of December 31, 2015, 2014 and 2013 was 2.9%, 3.0% and 3.0%, respectively. Sierra Pacific is required to file a utility plant depreciation study every six years as a companion filing with the triennial general rate case filings.

Construction work-in-progress is related to the construction of regulated assets.

Impairment of Regulated Assets Not In Rates

Sierra Pacific recorded an impairment charge of $12 million and $4 million in operating and maintenance on the Consolidated Statements of Operations for the years ended December 31, 2014 and 2013, respectively, related to the recovery of certain assets not currently in rates. Included in the 2014 impairment is $8 million related to the settlement of the "companion filing" in the 2014 Nevada Power general rate case. Impairment of regulated assets not in rates were not material in 2015.

(4) Jointly Owned Utility Facilities

Under joint facility ownership agreements, Sierra Pacific, as tenants in common, has undivided interests in jointly owned generation and transmission facilities. Sierra Pacific 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 Sierra Pacific's share of the expenses of these facilities. The amounts shown in the table below represent Sierra Pacific's share in each jointly owned facility as of December 31, 2015 (dollars in millions):

	Sierra Pacific's Share	Facility In Service	Accumulated Depreciation	Construction Work-in-Progress
Valmy Generating Station	50%	$ 382	$ 209	$ 2
ON Line Transmission Line	1	8	1	—
Valmy Transmission	50	4	2	—
Total		$ 394	$ 212	$ 2

(5) Regulatory Matters

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

	Weighted Average Remaining Life	2015	2014
Employee benefit plans(2)	10 years	$ 126	$ 115
Deferred income taxes(1)	28 years	90	94
Merger costs from 1999 merger	31 years	83	87
Abandoned projects	9 years	44	51
Deferred energy costs	2 years	—	32
Loss on reacquired debt	17 years	22	24
Other	Various	67	73
Total regulatory assets		$ 432	$ 476
Reflected as:			
Current assets		$ —	$ 32
Other assets		432	444
Total regulatory assets		$ 432	$ 476

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

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

Sierra Pacific had regulatory assets not earning a return on investment of $254 million and $269 million as of December 31, 2015 and 2014, respectively. In 2015 the regulatory assets not earning a return on investment consist of deferred income taxes, merger costs from 1999 merger, loss on reacquired debt, legacy meters, a portion of abandoned projects and asset retirement obligations.

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

	Weighted Average Remaining Life	2015	2014
Cost of removal[1]	40 years	$ 208	$ 233
Deferred energy costs	2 years	66	—
Renewable energy program	1 year	8	32
Other	Various	26	36
Total regulatory liabilities		$ 308	$ 301
Reflected as:			
Current liabilities		$ 78	$ 39
Other long-term liabilities		230	262
Total regulatory liabilities		$ 308	$ 301

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

Deferred Energy

Nevada statutes permit regulated utilities to adopt deferred energy accounting procedures. The intent of these procedures is to ease the effect on customers of fluctuations in the cost of purchased natural gas, fuel and electricity and are subject to annual prudency review by the PUCN.

Under deferred energy accounting, to the extent actual fuel and purchased power costs exceed fuel and purchased power costs recoverable through current rates that excess is not recorded as a current expense on the Consolidated Statements of Operations but rather is deferred and recorded as a regulatory asset on the Consolidated Balance Sheets and is included in the table above as deferred energy costs. Conversely, a regulatory liability is recorded to the extent fuel and purchased power costs recoverable through current rates exceed actual fuel and purchased power costs and is included in the table above as deferred energy costs. These excess amounts are reflected in quarterly adjustments to rates and recorded as cost of fuel, energy and capacity in future time periods.

Energy Efficiency Implementation Rates and Energy Efficiency Program Rates

The PUCN authorizes an electric utility to recover lost revenue that is attributable to the measurable and verifiable effects associated with the implementation of efficiency and conservation programs approved by the PUCN through energy efficiency implementation rates ("EEIR"). As a result, Sierra Pacific files annually to adjust energy efficiency program rates ("EEPR") and EEIR for over- or under-collected balances, which are effective in October of the same year.

The PUCN's final order approving the BHE Merger stipulated that Sierra Pacific will not seek recovery of any lost revenue for calendar year 2013 and, for the calendar year 2014 in an amount that exceeds 50% of the lost revenue that Sierra Pacific could otherwise request. In February 2014, Sierra Pacific filed an application with the PUCN to reset the EEIR and EEPR. In June 2014, the PUCN accepted a stipulation to adjust the EEIR, as of July 1, 2014, to collect 50% of the estimated lost revenue that Sierra Pacific would otherwise be allowed to recover for the 2014 calendar year. The EEIR was effective from July through December 2014 and reset on January 1, 2015 and was in effect through September 2015.

In February 2015, Sierra Pacific filed an application to reset the EEIR and EEPR. In August 2015, the PUCN accepted a stipulation for Sierra Pacific to calculate the base EEIR using a revised methodology for calculating lost revenue and for Sierra Pacific to make a $1 million reduction to the EEPR revenue requirement to more accurately reflect the actual level of spending and to minimize any over collection from its customers. The reset of the EEIR and EEPR was effective October 1, 2015 and remains in effect through September 30, 2016. To the extent Sierra Pacific's earned rate of return exceeds the rate of return used to set base general rates, Sierra Pacific is required to refund to customers EEIR revenue collected. The current EEIR liability for Sierra Pacific is $3 million and $2 million, which is included in current regulatory liabilities on the Consolidated Balance Sheets as of December 31, 2015 and 2014, respectively.

General Rate Case

In connection with Nevada Power's general rate case filing in May 2014, as required by the PUCN, Sierra Pacific made a "companion filing" for the purpose of documenting the costs and benefits of Sierra Pacific's investment in the advanced service delivery program. In October 2014, the PUCN issued an order in the companion filing issued with the general rate case order that, among other things, provided for the implementation of new rates effective January 1, 2015 to begin recovery of costs associated with advance service delivery. The recovery of advanced service delivery costs will increase annual revenue approximately $10 million. As a result of the PUCN order in the companion filing issued with the Nevada Power general rate case order, Sierra Pacific recorded $7 million in asset impairments related to property, plant and equipment and $1 million of regulatory asset impairments, which are included in operating and maintenance on the Consolidated Statements of Operations for the year ended December 31, 2014.

2013 FERC Transmission Rate Case

In May 2013, the Nevada Utilities, filed an application with the FERC to establish single system transmission and ancillary service rates. The combined filing requested incremental rate relief of $17 million annually to be effective January 1, 2014. In August 2013, the FERC granted the companies' request for a rate effective date of January 1, 2014 subject to refund, and set the case for hearing or settlement discussions. On January 1, 2014, Sierra Pacific implemented the filed rates in this case subject to refund as set forth in the FERC's order.

In September 2014, the Nevada Utilities, filed an unopposed settlement offer with the FERC on behalf of NV Energy and the intervening parties providing rate relief of $4 million. The settlement offer would resolve all outstanding issues related to this case. In addition, a preliminary order from the administrative law judge granting the motion for interim rate relief was issued, which authorizes Sierra Pacific to institute the interim rates effective September 1, 2014, and begin billing transmission customers under the settlement rates for service provided on and after that date. In January 2015, the FERC approved the settlement and refunds were issued.

(6) Credit Facility

Sierra Pacific has a $250 million secured credit facility expiring in March 2018. The credit facility, which is for general corporate purposes for the issuance of letters of credit, has a variable interest rate based on London Interbank Offered Rate or a base rate, at Sierra Pacific's option, plus a spread that varies based on Sierra Pacific's credit ratings for its senior secured long-term debt securities. As of December 31, 2015 and 2014, Sierra Pacific had no borrowings outstanding under the credit facility. Amounts due under Sierra Pacific's credit facility are collateralized by Sierra Pacific's general and refunding mortgage bonds. The credit facility requires Sierra Pacific's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.68 to 1.0 as of the last day of each quarter.

(7) Long-Term Debt and Financial and Capital Lease Obligations

Sierra Pacific's long-term debt consists of the following, including unamortized premiums, discounts and debt issuance costs, as of December 31 (dollars in millions):

	Par Value	2015	2014
General and Refunding Mortgage Securities:			
6.000% Series M, due 2016	$ 450	$ 450	$ 451
3.375% Series T, due 2023	250	248	247
6.750% Series P, due 2037	252	255	255
Variable-rate series (2015-0.733% to 1.054%, 2014-0.464% to 0.466%):			
Pollution Control Revenue Bonds Series 2006A, due 2031	58	58	58
Pollution Control Revenue Bonds Series 2006B, due 2036	75	74	74
Pollution Control Revenue Bonds Series 2006C, due 2036	81	80	79
Capital and financial lease obligations - 2.700% to 8.548%, due through 2054	37	37	26
Total long-term debt and financial and capital leases	$ 1,203	$ 1,202	$ 1,190
Reflected as:			
Current portion of long-term debt and financial and capital lease obligations		$ 453	$ 1
Long-term debt and financial and capital lease obligations		749	1,189
Total long-term debt and financial and capital leases		$ 1,202	$ 1,190

The consummation of the BHE Merger triggered mandatory redemption requirements under financing agreements of Sierra Pacific. As a result, Sierra Pacific offered to purchase $702 million of debt at 101% of par. The tender offer expired in January 2014 with no amounts tendered.

Annual Payment on Long-Term Debt and Financial and Capital Leases

The annual repayments of long-term debt and capital and financial leases for the years beginning January 1, 2016 and thereafter, are as follows (in millions):

	Long-term Debt	Capital and Financial Lease Obligations	Total
2016	$ 450	$ 6	$ 456
2017	—	4	4
2018	—	4	4
2019	—	4	4
2020	—	3	3
Thereafter	716	53	769
Total	1,166	74	1,240
Unamortized premium, discount and debt issuance cost	(1)	—	(1)
Amounts representing interest	—	(37)	(37)
Total	$ 1,165	$ 37	$ 1,202

The issuance of General and Refunding Mortgage Securities by Sierra Pacific is subject to PUCN approval and is limited by available property and other provisions of the mortgage indentures. As of December 31, 2015, approximately $3.7 billion (based on original cost) of Sierra Pacific's property was subject to the liens of the mortgages.

Financial and Capital Lease Obligations

- Sierra Pacific has master leasing agreements of which various pieces of equipment qualify as capital leases. The remaining equipment is treated as operating leases. Lease terms average seven years under the master lease agreement. Capital assets of $3 million were included in property, plant and equipment, net as of December 31, 2015 and 2014.
- ON Line was placed in-service on December 31, 2013. The Nevada Utilities entered into a long-term transmission use agreement, in which the Nevada Utilities have 25% interest and Great Basin Transmission South, LLC has 75% interest. Refer to Note 4 for additional information. The Nevada Utilities share of the long-term transmission use agreement and ownership interest is split at 5% for Sierra Pacific and 95% for Nevada Power. The term is for 41 years with the agreement ending December 31, 2054. Payments began on January 31, 2014. ON Line assets of $22 million were included in property, plant and equipment, net as of December 31, 2015 and 2014.
- In 2015, Sierra Pacific entered into a 20-year capital lease for the Fort Churchill Solar Array. Capital assets of $12 million were included in property, plant and equipment, net as of December 31, 2015.

(8) Fair Value Measurements

The carrying value of Sierra Pacific's cash, certain cash equivalents, receivables, investments held in Rabbi trusts, payables, accrued liabilities and short-term borrowings approximates fair value because of the short-term maturity of these instruments. Sierra Pacific has various financial assets and liabilities, principally related to derivative contracts, that are measured at fair value on the Consolidated Balance Sheets 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 Sierra Pacific 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 Sierra Pacific's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. Sierra Pacific develops these inputs based on the best information available, including its own data.

Sierra Pacific's long-term debt is carried at cost on the Consolidated Balance Sheets. The fair value of Sierra Pacific'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 Sierra Pacific'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 Sierra Pacific's long-term debt as of December 31 (in millions):

	2015		2014	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 1,165	$ 1,248	$ 1,164	$ 1,301

(9) Income Taxes

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

	2015	2014	2013
Current – Federal	$ —	$ —	$ (2)
Deferred:			
Federal	48	48	38
State	—	—	(2)
Total deferred	48	48	36
Investment tax credits	(1)	(1)	(1)
Total income tax expense	$ 47	$ 47	$ 33

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

	2015	2014	2013
Federal statutory income tax rate	35%	35%	35%
Non-deductible BHE Merger related expenses	—	—	1
Effects of ratemaking	1	1	1
Other	—	(1)	—
Effective income tax rate	36%	35%	37%

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

	2015	2014
Deferred income tax assets:		
Net operating loss and credit carryforwards	$ 39	$ 56
Employee benefit plans	25	22
Regulatory liabilities	19	21
Capital and financial lease liabilities	13	9
Customer Advances	8	7
Other	12	15
Total deferred income tax assets	$ 116	$ 130
Deferred income tax liabilities:		
Property related items	$ (538)	$ (478)
Regulatory assets	(121)	(147)
Capital and financial leases	(13)	(9)
Other	(14)	(20)
Total deferred income tax liabilities	$ (686)	$ (654)
Net deferred income tax liability	$ (570)	$ (524)

The following table provides Sierra Pacific's federal net operating loss and tax credit carryforwards and expiration dates as of December 31, 2015 (in millions):

Net operating loss carryforwards	$	95
Deferred income taxes on federal net operating loss carryforwards	$	33
Expiration dates		2031 - 2035
Other tax credits	$	5
Expiration dates		2016 - 2035

The United States federal jurisdiction is the only significant income tax jurisdiction for NV Energy. In July 2012, the United States Internal Revenue Service and the Joint Committee on Taxation concluded their examination of NV Energy with respect to its United States federal income tax returns for December 31, 2005 through December 31, 2008.

(10) Related Party Transactions

Sierra Pacific provided electricity to Nevada Power of $2 million, $8 million and $1 million for the years ended December 31, 2015, 2014 and 2013, respectively. Receivables associated with these transactions were $1 million and $4 million as of December 31, 2015 and 2014. Sierra Pacific purchased electricity from Nevada Power of $69 million, $33 million and $36 million for the years ended December 31, 2015, 2014 and 2013, respectively. Payables associated with these transactions were $15 million and $7 million as of December 31, 2015 and 2014, respectively.

Sierra Pacific incurs intercompany administrative and shared facility costs with NV Energy and Nevada Power. These transactions are governed by an intercompany service agreement and are priced at cost. NV Energy provided services to Sierra Pacific of $6 million, $9 million and $19 million for the years ending December 31, 2015, 2014 and 2013, respectively. Sierra Pacific provided services to Nevada Power of $16 million, $16 million, and $- million for the years ended December 31, 2015, 2014 and 2013, respectively. Nevada Power provided services to Sierra Pacific of $22 million, $20 million, and $- million for the years ended December 31, 2015, 2014 and 2013, respectively. As of December 31, 2015 and 2014, Sierra Pacific's Consolidated Balance Sheets included amounts due to NV Energy of $21 million and $20 million, respectively. There were no receivables due from NV Energy as of December 31, 2015 and 2014. As of December 31, 2015 and 2014, Sierra Pacific's Consolidated Balance Sheets included payables due to Nevada Power of $6 million and $5 million, respectively. There were no receivables due from Nevada Power as of December 31, 2015 and 2014.

Certain disbursements for accounts payable and payroll are made by NV Energy on behalf of Sierra Pacific and reimbursed automatically when settled by the bank. These amounts are recorded as accounts payable at the time of disbursement.

(11) Retirement Plan and Postretirement Benefits

Sierra Pacific is a participant in benefit plans sponsored by NV Energy. The NV Energy Retirement Plan includes a qualified pension plan ("Qualified Pension Plan") and a supplemental executive retirement plan and a restoration plan (collectively, "Non-Qualified Pension Plans") that provide pension benefits for eligible employees. The NV Energy Comprehensive Welfare Benefit and Cafeteria Plan provides certain postretirement health care and life insurance benefits for eligible retirees ("Other Postretirement Plans") on behalf of Sierra Pacific. Sierra Pacific contributed $20 million to the Qualified Pension Plan for the year ended December 31, 2013, and did not make a contribution in 2014 and 2015. For the Other Postretirement Plans, Sierra Pacific contributed $5 million for the year ended December 31, 2013, and did not make a contribution in 2014 and 2015. Sierra Pacific did not make any contributions to the Non-Qualified Pension Plans for the years ended December 31, 2015, 2014 and 2013. Amounts attributable to Sierra Pacific were allocated from NV Energy based upon the current, or in the case of retirees, previous, employment location. Offsetting regulatory assets and liabilities have been recorded related to the amounts not yet recognized as a component of net periodic benefit costs that will be included in regulated rates. Net periodic benefit costs not included in regulated rates are included in accumulated other comprehensive loss, net.

Amounts payable to NV Energy are included on the Consolidated Balance Sheets and consist of the following as of December 31 (in millions):

	2015	2014
Qualified Pension Plan -		
Other long-term liabilities	$ (29)	$ (13)
Non-Qualified Pension Plans:		
Other current liabilities	(1)	(1)
Other long-term liabilities	(9)	(10)
Other Postretirement Plans -		
Other long-term liabilities	(32)	(33)

(12) Asset Retirement Obligations

Sierra Pacific 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.

Sierra Pacific 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 generation, 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. These accruals totaled $208 million and $233 million as of December 31, 2015 and 2014, respectively.

The following table presents Sierra Pacific's ARO liabilities by asset type as of December 31 (in millions):

	2015	2014
Asbestos	$ 4	$ 5
Evaporative ponds and dry ash landfills	3	2
Other	3	4
Total asset retirement obligations	$ 10	$ 11

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

	2015	2014
Beginning balance	$ 11	$ 16
Change in estimated costs	—	(6)
Retirements	(1)	—
Accretion	—	1
Ending balance	$ 10	$ 11
Reflected as:		
Other current liabilities	$ —	$ 3
Other long-term liabilities	10	8
	$ 10	$ 11

Certain of Sierra Pacific's decommissioning and reclamation obligations relate to jointly-owned facilities, and as such, Sierra Pacific 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, the respective subsidiary may be obligated to absorb, directly or by paying additional sums to the entity, a proportionate share of the defaulting party's liability. Sierra Pacific's estimated share of the decommissioning and reclamation obligations are primarily recorded as ARO liabilities in other long-term liabilities on the Consolidated Balance Sheets.

In December 2014, the United States Environmental Protection Agency ("EPA") 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 was published in the Federal Register in April 2015 and was effective in October 2015. The effects of the new rule did not have a material impact on Sierra Pacific's ARO balance. The impact of this new rule is reflected in the December 31, 2015 change in estimated costs above.

(13) Commitments and Contingencies

Environmental Laws and Regulations

Sierra Pacific 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 Sierra Pacific's current and future operations. Sierra Pacific believes it is in material compliance with all applicable laws and regulations.

Valmy Generation Station

In June 2009, Sierra Pacific received a request for information from the EPA Region 9 under Section 114 of the Clean Air Act requesting current and historical operations and capital project information for Sierra Pacific's Valmy Generating Station located in Valmy, Nevada. Sierra Pacific co-owns and operates this coal-fueled generating facility. Idaho Power Company owns the remaining 50%. The EPA's Section 114 information request does not allege any incidents of non-compliance at the plant, and there have been no other new enforcement-related proceedings that have been initiated by the EPA relating to the plant. Sierra Pacific completed its responses to the EPA in December 2009 and will continue to monitor developments relating to this Section 114 request. At this time, Sierra Pacific cannot predict the impact, if any, associated with this information request.

Legal Matters

Sierra Pacific is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. Sierra Pacific does not believe that such normal and routine litigation will have a material impact on its consolidated financial results.

Commitments

Sierra Pacific has the following firm commitments that are not reflected on the Consolidated Balance Sheet. Minimum payments as of December 31, 2015 are as follows (in millions):

	2016	2017	2018	2019	2020	2021 and Thereafter	Total
Contract type:							
Fuel and capacity contract commitments	$ 207	$ 159	$ 109	$ 88	$ 75	$ 444	$ 1,082
Operating leases and easements	6	4	3	3	3	65	84
Maintenance, service and other contracts	5	4	4	5	5	22	45
Total commitments	$ 218	$ 167	$ 116	$ 96	$ 83	$ 531	$ 1,211

Fuel and Capacity Contract Commitments

Purchased Power

Sierra Pacific has several contracts for long-term purchase of electric energy which have been approved by the PUCN. The expiration of these contracts range from 2016 to 2039. Purchased power includes contracts which meet the definition of a lease. Sierra Pacific's rent expense for purchase power contracts which met the lease criteria for 2015, 2014 and 2013 were $65 million, $68 million and $63 million, respectively, and are recorded as cost of fuel, energy and capacity on the Consolidated Statements of Operations.

Coal and Natural Gas

Sierra Pacific has several long-term contracts for the transport of coal that expire from 2016 to 2018. Additionally, gas transportation contracts expire from 2017 to 2046 and the gas supply contracts expire from 2016 to 2017.

Operating Leases

Sierra Pacific has non-cancelable operating leases primarily for office equipment, office space, certain operating facilities, vehicles and land. These leases generally require Sierra Pacific 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. Sierra Pacific also has non-cancelable easements for land. Rent expense on non-cancelable operating leases totaled $7 million, $6 million and $5 million for the year-ended December 31, 2015, 2014 and 2013, respectively.

Maintenance, Service and Other Contracts

Sierra Pacific has long-term service agreements for the performance of maintenance on generation units. Obligation amounts are based on estimated usage. The estimated expiration of these service agreements range from 2023 to 2039.

(14) 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):

	2015	2014	2013
Supplemental disclosure of cash flow information -			
Interest paid, net of amounts capitalized	$ 54	$ 54	$ 59
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	$ 24	$ 31	$ 37
Capital and financial lease obligations incurred	$ 13	$ 1	$ 22

(15) Segment Information

Sierra Pacific has identified two reportable operating segments: regulated electric and regulated natural gas. The regulated electric segment derives most of its revenue from regulated retail sales of electricity to residential, commercial, and industrial customers and from wholesale sales. The regulated natural gas segment derives most of its revenue from regulated retail sales of natural gas to residential, commercial, and industrial customers and also obtains revenue by transporting natural gas owned by others through its distribution system. Pricing for regulated electric and regulated natural gas sales are established separately by the PUCN; therefore, management also reviews each segment separately to make decisions regarding allocation of resources and in evaluating performance.

Sierra Pacific believes presenting gross margin allows the reader to assess the impact of Sierra Pacific's regulatory treatment and its overall regulatory environment on a consistent basis and is meaningful. Gross margin is calculated as operating revenue less cost of fuel, energy and capacity and natural gas purchased for resale.

The following tables provide information on a reportable segment basis for the years ended December 31 (in millions):

	Years Ended December 31,		
	2015	2014	2013
Operating revenue:			
Regulated electric	$ 810	$ 779	$ 747
Regulated gas	137	125	106
Total operating revenue	$ 947	$ 904	$ 853
Cost of sales:			
Regulated electric	$ 374	$ 361	$ 292
Regulated gas	84	76	56
Total cost of sales	$ 458	$ 437	$ 348
Gross margin:			
Regulated electric	$ 436	$ 418	$ 455
Regulated gas	53	49	50
Total gross margin	$ 489	$ 467	$ 505
Operating and maintenance:			
Regulated electric	$ 146	$ 140	$ 176
Regulated gas	17	18	21
Total operating and maintenance	$ 163	$ 158	$ 197
Depreciation and amortization:			
Regulated electric	$ 96	$ 90	$ 106
Regulated gas	17	15	17
Total depreciation and amortization	$ 113	$ 105	$ 123
Operating income:			
Regulated electric	$ 168	$ 165	$ 134
Regulated gas	16	13	6
Total operating income	$ 184	$ 178	$ 140
Interest expense:			
Regulated electric	$ 56	$ 57	$ 56
Regulated gas	5	4	5
Total interest expense	$ 61	$ 61	$ 61
Income tax expense:			
Regulated electric	$ 43	$ 43	$ 32
Regulated gas	4	4	1
Total income tax expense	$ 47	$ 47	$ 33

	Years Ended December 31,		
	2015	2014	2013
Capital expenditures:			
Regulated electric	$ 229	$ 168	$ 125
Regulated gas	23	18	14
Total capital expenditures	$ 252	$ 186	$ 139

	As of December 31,		
Total assets:	2015	2014	2013
Regulated electric	$ 3,060	$ 2,984	$ 2,905
Regulated gas	316	322	329
Regulated common assets[1]	111	30	77
Total assets	$ 3,487	$ 3,336	$ 3,311

(1) Consists principally of cash and cash equivalents not included in either the regulated electric or regulated natural gas segments.

(16) Unaudited Quarterly Operating Results (in millions)

	Three-Month Periods Ended			
	March 31, 2015	June 30, 2015	September 30, 2015	December 31, 2015
Regulated electric operating revenue	$ 196	$ 201	$ 228	$ 185
Regulated natural gas operating revenue	50	26	18	43
Operating income	43	37	66	38
Net income	19	16	33	15

	Three-Month Periods Ended			
	March 31, 2014	June 30, 2014	September 30, 2014	December 31, 2014
Regulated electric operating revenue	$ 177	$ 179	$ 233	$ 190
Regulated natural gas operating revenue	44	21	18	42
Operating income	46	31	60	41
Net income	22	14	31	20

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, each of Berkshire Hathaway Energy Company, PacifiCorp, MidAmerican Energy Company, MidAmerican Funding, LLC, Nevada Power Company and Sierra Pacific Power Company carried out separate evaluations, under the supervision and with the participation of each such entity's management, including its Chief Executive Officer (principal executive officer) and its Chief Financial Officer (principal financial officer), or persons performing similar functions, of the effectiveness of the design and operation of its disclosure controls and procedures (as defined in Rule 13a-15(e) promulgated under the Securities and Exchange Act of 1934, as amended). Based upon these evaluations, management of each such entity, including its Chief Executive Officer (principal executive officer) and its Chief Financial Officer (principal financial officer), or persons performing similar functions, in each case, concluded that the disclosure controls and procedures for such entity were effective to ensure that information required to be disclosed by such entity 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 its management, including its Chief Executive Officer (principal executive officer) and its Chief Financial Officer (principal financial officer), or persons performing similar functions, in each case, as appropriate to allow timely decisions regarding required disclosure by it. Each such entity hereby states that there has been no change in its internal control over financial reporting during the quarter ended December 31, 2015 that has materially affected, or is reasonably likely to materially affect, its internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

Management of each of Berkshire Hathaway Energy Company, PacifiCorp, MidAmerican Energy Company, MidAmerican Funding, LLC, Nevada Power Company and Sierra Pacific Power Company, respectively, is responsible for establishing and maintaining, for such entity, 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 management for each such entity, including its Chief Executive Officer (principal executive officer) and its Chief Financial Officer (principal financial officer), or persons performing similar functions, in each case, such management conducted an evaluation for the relevant entity of the effectiveness of internal control over financial reporting as of December 31, 2015, as required by the Securities Exchange Act of 1934 Rule 13a-15 (c). In making this assessment, management for each such respective entity, 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)," management for each such respective entity, concluded that internal control over financial reporting for such entity was effective as of December 31, 2015.

Berkshire Hathaway Energy Company	PacifiCorp	MidAmerican Energy Company
February 26, 2016	February 26, 2016	February 26, 2016
MidAmerican Funding, LLC	Nevada Power Company	Sierra Pacific Power Company
February 26, 2016	February 26, 2016	February 26, 2016

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

BERKSHIRE HATHAWAY ENERGY

BHE is a consolidated subsidiary of Berkshire Hathaway. Each director was elected based on individual responsibilities, experience in the energy industry and functional expertise. BHE's Board of Directors appoints executive officers annually. There are no family relationships among the executive officers, nor, except as set forth in employment agreements, 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, 2016, with respect to the current directors and executive officers of BHE:

GREGORY E. ABEL, 53, Chairman of the Board of Directors since 2011, Chief Executive Officer since 2008, director since 2000, and President since 1998. Mr. Abel joined BHE in 1992 and has extensive executive management experience in the energy industry. Mr. Abel is also a director of PacifiCorp and The Kraft Heinz Company.

PATRICK J. GOODMAN, 49, Executive Vice President and Chief Financial Officer since 2012. Mr. Goodman was Senior Vice President and Chief Financial Officer from 1999 to 2012. Mr. Goodman joined BHE in 1995. Mr. Goodman is a director of PacifiCorp and a manager of MidAmerican Funding, LLC.

NATALIE L. HOCKEN, 46, Senior Vice President and General Counsel since 2015. Ms. Hocken was Senior Vice President, Transmission and System Operations of PacifiCorp from 2012 to 2015 and Vice President and General Counsel of Pacific Power from 2007 to 2012. Ms. Hocken joined PacifiCorp in 2002. Ms. Hocken is a director of PacifiCorp.

WARREN E. BUFFETT, 85, Director. Mr. Buffett has been a director of BHE since 2000 and has been Chairman of the Board of Directors and Chief Executive Officer of Berkshire Hathaway for more than five years. Mr. Buffett is also a director of The Kraft Heinz Company and Precision Castparts Corp. Mr. Buffett previously served as a director of The Washington Post Company. Mr. Buffett has significant experience as Chairman and Chief Executive Officer of Berkshire Hathaway.

WALTER SCOTT, JR., 84, Director. Mr. Scott has been a director of BHE since 1991. Mr. Scott is also a director of Peter Kiewit Sons' Inc., Berkshire Hathaway and Valmont Industries, Inc. Mr. Scott previously served as Chairman of the Board of Directors of Level 3 Communications, Inc., a successor to certain businesses of Peter Kiewit Sons' Inc., until 2014. Mr. Scott has significant experience and financial expertise as a past chief executive officer and as a director of both public and private corporations and as chairman of a major charitable foundation.

MARC D. HAMBURG, 66, Director. Mr. Hamburg has been a director of BHE since 2000 and has been Chief Financial Officer of Berkshire Hathaway for more than five years. Mr. Hamburg has been Senior Vice President of Berkshire Hathaway since 2008 and was a Vice President of Berkshire Hathaway from 1992 to 2008. Mr. Hamburg was Berkshire Hathaway's Treasurer from 1987 to 2010. Mr. Hamburg is also a director of Precision Castparts Corp. Mr. Hamburg has significant financial experience, including expertise in mergers and acquisitions; accounting; treasury; and tax functions.

Board's Role in the Risk Oversight Process

BHE's Board of Directors is comprised of a combination of BHE senior management, Berkshire Hathaway senior executives and BHE owners who have responsibility for the management and oversight of risk. BHE's Board of Directors has not established a separate risk management and oversight committee.

Audit Committee and Audit Committee Financial Expert

The audit committee of the Board of Directors is comprised of Mr. Marc D. Hamburg. The Board of Directors has determined that Mr. Hamburg qualifies as an "audit committee financial expert," as defined by SEC rules, based on his education, experience and background. Based on the standards of the New York Stock Exchange LLC, on which the common stock of BHE's majority owner, Berkshire Hathaway, is listed, BHE's Board of Directors has determined that Mr. Hamburg is not independent because of his employment by Berkshire Hathaway.

Code of Ethics

BHE 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 filed as an exhibit to this Annual Report on Form 10-K.

PACIFICORP

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, 2016, with respect to the current directors and executive officers of PacifiCorp:

GREGORY E. ABEL, 53, 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 and President since 1998. Mr. Abel joined BHE in 1992 and has extensive executive management experience in the energy industry. Mr. Abel is also a director of The Kraft Heinz Company.

DOUGLAS L. ANDERSON, 57, Director. Mr. Anderson has been a director of PacifiCorp since 2006 and Chief Corporate Counsel and Corporate Secretary of BHE since 2015. Mr. Anderson was Executive Vice President, General Counsel and Corporate Secretary of BHE from 2012 to 2015 and 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.

STEFAN A. BIRD, 49, President and Chief Executive Officer of Pacific Power and director of PacifiCorp since 2015. Mr. Bird was Senior Vice President, Commercial and Trading, for PacifiCorp Energy, a former division of PacifiCorp, from 2007 to 2014. Mr. Bird joined BHE in 1998 and has significant operational, public policy and leadership experience in the energy industry, including expertise in energy supply management, resource acquisition and federal and state regulatory matters.

CINDY A. CRANE, 54, President and Chief Executive Officer of Rocky Mountain Power since 2014 and director of PacifiCorp since 2015. Ms. Crane was Vice President of Interwest Mining Company, a subsidiary of PacifiCorp, from 2009 to 2014. Ms. Crane joined PacifiCorp in 1990 and has significant strategy, operational and leadership experience in the energy industry, including complex commercial negotiations.

PATRICK J. GOODMAN, 49, 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, 46, Director. Ms. Hocken has been a director of PacifiCorp since 2007 and Senior Vice President and General Counsel of BHE since 2015. Ms. Hocken was Senior Vice President, Transmission and System Operations of PacifiCorp from 2012 to 2015 and Vice President and General Counsel of Pacific Power from 2007 to 2012. 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.

ANDREA L. KELLY, 51, Director. Ms. Kelly has been a director of PacifiCorp and Senior Vice President, Legislative and Regulatory Strategy of BHE since 2015. Prior to joining BHE, Ms. Kelly was PacifiCorp's Senior Vice President, Strategic Business Performance, Legislative and Regulatory Strategy from 2012 to 2015 and PacifiCorp's Vice President of Regulation from 2007 to 2012. Ms. Kelly joined PacifiCorp in 1995 and has significant operational, public policy and leadership experience in the energy industry, including expertise in strategic initiatives and regulatory matters.

NIKKI L. KOBLIHA, 43, Vice President and Chief Financial Officer of PacifiCorp since 2015. Ms. Kobliha joined PacifiCorp in 1997 and has held various positions within PacifiCorp Finance. Ms. Kobliha has significant financial, accounting and leadership experience in the energy industry, including expertise in financial reporting to the SEC and FERC.

R. PATRICK REITEN, 54, President and Chief Executive Officer of PacifiCorp Transmission since 2015 and director of PacifiCorp since 2006. Mr. Reiten was President and Chief Executive Officer of Pacific Power from 2006 to 2015. 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.

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, 2015, 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.

MIDAMERICAN FUNDING, MIDAMERICAN ENERGY, NEVADA POWER AND SIERRA PACIFIC

Information required by Item 10 is omitted pursuant to General Instruction I(2)(c) to Form 10-K.

Item 11. Executive Compensation

BERKSHIRE HATHAWAY ENERGY

Compensation Discussion and Analysis

Compensation Philosophy and Overall Objectives

BHE believes that the compensation paid to each of its Chairman, President and Chief Executive Officer, or Chairman and CEO, its Chief Financial Officer, or CFO, and its other most highly compensated executive officers, to whom BHE refers collectively as its Named Executive Officers, or NEOs, should be closely aligned with BHE's 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 the organization. BHE's compensation programs are designed to provide its 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 BHE believes contribute to its long-term success.

How is Compensation Determined

BHE's Compensation Committee is comprised of Messrs. Warren E. Buffett and Walter Scott, Jr. The Compensation Committee is responsible for the establishment and oversight of BHE's compensation policy. Approval of compensation decisions for BHE's NEOs is made by the Compensation Committee, unless specifically delegated. Although the Compensation Committee reviews each NEO's complete compensation package at least annually, it has delegated to the Chairman and CEO authority to approve off-cycle pay changes, performance awards and participation in other employee benefit plans and programs for the other NEOs.

BHE's 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. BHE does not specifically use other companies as benchmarks when establishing its NEOs' compensation. However, the Compensation Committee reviews peer company data when making annual base salary and incentive recommendations for the Chairman and CEO. The peer companies for 2015 were American Electric Power Company, Inc., Consolidated Edison, Inc., Dominion Resources, Inc., Duke Energy Corporation, Edison International, Entergy Corporation, Exelon Corporation, FirstEnergy Corp., NextEra Energy, Inc., PG&E Corporation, PPL Corporation, Public Service Enterprise Group Incorporated, Sempra Energy, The Southern Company and Xcel Energy Inc.

BHE engages the compensation practice of Willis Towers Watson PLC, or Willis Towers Watson, to research and document the peer company data to be reviewed by the Compensation Committee when making annual base salary and incentive recommendations for the Chairman and CEO. The fee paid to Willis Towers Watson for this service was $8,036 in 2015. BHE also engages Willis Towers Watson to provide other services unrelated to executive compensation, including actuarial, administration and consulting services related to BHE's retirement plans. These services are approved by senior management and the aggregate fees paid to Willis Towers Watson for these services were $2,858,907 in 2015. BHE's Board of Directors is not involved in the selection or approval of Willis Towers Watson for these services.

Discussion and Analysis of Specific Compensation Elements

Base Salary

BHE determines base salaries for all of its NEOs by reviewing its overall performance and each NEO's performance, the value each NEO brings to BHE 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 is determined on a subjective basis after consideration of these factors and is not based on target percentiles or other formal criteria.

The Chairman and CEO makes recommendations regarding the other NEOs' base salaries, and the Compensation Committee sets the Chairman and CEO's base salary. All merit increases are approved by the Compensation Committee and take effect on January 1 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. Base salaries for all NEOs increased on average by 2.26% effective January 1, 2015. Ms. Hocken's base salary increased to $400,000 effective July 10, 2015, commensurate with her becoming senior vice president and general counsel. Ms. Sammon's base salary increased to $335,000 effective August 1, 2015, commensurate with her becoming president and CEO, HomeServices Mortgage. There were no other base salary changes for BHE's NEOs during the year after the January 1, 2015 merit increase.

Short-Term Incentive Compensation

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

Performance Incentive Plan

Under BHE's Performance Incentive Plan, or PIP, all NEOs are eligible to earn an annual discretionary cash incentive award, which is determined on a subjective basis and is not based on a specific formula or cap. A variety of factors are considered in determining each NEO's annual incentive award including the NEO's performance, BHE's overall performance and each NEO's contribution to that overall performance. An individual NEO's performance is evaluated 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 the determination of the amounts paid to each NEO under the PIP for 2015. The Chairman and CEO recommends annual incentive awards for the other NEOs to the Compensation Committee prior to the last committee meeting of each year, held in the fourth quarter. The Compensation Committee determines the Chairman and CEO's award, which is based on BHE's overall performance and direction and is not based on the performance of any specific subsidiary. If approved by the Compensation Committee, awards are paid prior to year-end.

Performance Awards

In addition to the annual awards under the PIP, BHE may grant cash performance awards periodically during the year to one or more NEOs to reward the accomplishment of significant non-recurring tasks or projects. These awards are discretionary and are approved by the Chairman and CEO, as delegated by the Compensation Committee. In December 2015, an award was granted to Mr. Goodman in recognition of his efforts related to certain renewables activities. Although Mr. Abel is eligible for performance awards, he has not been granted an award in the past five years.

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. BHE's current long-term incentive compensation program is cash-based. BHE has not issued stock options or other forms of equity-based awards since March 2000.

Long-Term Incentive Partnership Plan

The Berkshire Hathaway Energy Company Long-Term Incentive Partnership Plan, or LTIP, is designed to retain key employees and to align BHE's interests and the interests of the participating employees. Messrs. Goodman and Anderson and Mses. Hocken and Sammon participate in this plan, while BHE's Chairman and CEO does not. BHE's 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 Chairman and CEO approves eligibility to participate in the plan 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 Chairman and CEO 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. These cash-based awards are subject to mandatory deferral and equal annual vesting over a four-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 four-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.

Incremental Profit Sharing Plan

The Incremental Profit Sharing Plan, or IPSP, is designed to align BHE's interests and the interests of the Chairman and CEO. The IPSP provides for a cash award based upon BHE's achievement of a specified adjusted diluted earnings per share, or EPS, target for any calendar year. The EPS targets to achieve the award were established by the Compensation Committee in 2009 and are to be achieved no later than calendar year end 2015. The individual profit sharing award that may be earned is $12 million if BHE's EPS is greater than $26.86 per share, but less than or equal to $28.65 per share, $25 million if BHE's EPS is greater than $28.65 per share, but less than $30.55 per share, or $40 million if BHE's EPS is greater than $30.55 per share. Under the IPSP, Mr. Abel earned $40 million through December 31, 2015. Messrs. Goodman and Anderson and Mses. Hocken and Sammon do not participate in this plan.

Other Employee Benefits

Supplemental Executive Retirement Plan

The MidAmerican Energy Company Supplemental Executive Retirement Plan for Designated Officers, or SERP, provides additional retirement benefits to participants. BHE includes the SERP as part of the participating NEO's overall compensation in order to provide a comprehensive, competitive package and as a key retention tool. Messrs. Abel and Goodman participate in the SERP, and BHE has no plans to add new participants in the future. The SERP provides the participating NEOs annual retirement benefits of up to 65% of the participating NEO's total cash compensation in effect immediately prior to retirement, subject to an annual $1 million maximum retirement benefit. Total cash compensation means (a) the highest amount payable to a participant as monthly base salary during the five years immediately prior to retirement multiplied by 12, plus (b) the average of the participant's annual awards under an annual incentive bonus program during the three years immediately prior to the year of retirement and (c) special, additional or non-recurring bonus awards, if any, that are required to be included in total cash compensation pursuant to a participant's employment agreement or approved for inclusion by the Board of Directors. All participating NEOs have met the five-year service requirement under the plan. Mr. Goodman's SERP benefit will be reduced by the amount of his regular retirement benefit under the MidAmerican Energy Company Retirement Plan, his actuarially equivalent benefit under the fixed 401(k) contribution option and ratably for retirement between ages 55 and 65.

Deferred Compensation Plan

The Berkshire Hathaway Energy Company Executive Voluntary Deferred Compensation Plan and the PacifiCorp Executive Voluntary Deferred Compensation Plan, or the DCPs, provide a means for all NEOs to make voluntary deferrals of up to 50% of base salary and 100% of short-term incentive compensation awards. BHE includes the DCPs 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 DCPs receive a rate of return based on the returns of any combination of various investment options offered under the DCPs and selected by the participant. The plan allows participants to choose from three forms of distribution. The plan permits BHE to make discretionary contributions on behalf of participants; however, BHE has not made contributions to date.

Financial Planning and Tax Preparation

BHE reimburses NEOs for financial planning and tax preparation services. The value of the benefit is included in the NEO's taxable income. It is offered both as a competitive benefit itself and also to help ensure BHE's NEOs best utilize the other forms of compensation BHE provides to them.

Executive Life Insurance

BHE provides universal life insurance to Messrs. Abel and Goodman having a death benefit of two times annual base salary during employment less $50,000, reducing to one times annual base salary in retirement. The value of the benefit is included in the NEO's taxable income. BHE includes the executive life insurance as part of the participating NEO's overall compensation in order to provide a comprehensive, competitive package.

Potential Payments Upon Termination

Certain NEOs are entitled to post-termination payments in the event their employment is terminated under certain circumstances. BHE believes these post-termination payments are an important component of the competitive compensation package BHE offers to these NEOs.

Compensation Committee Report

The Compensation Committee, consisting of Messrs. Buffett and Scott, has reviewed and discussed the Compensation Discussion and Analysis with management and, based on this review and discussion, has recommended to the Board of Directors that the Compensation Discussion and Analysis be included in this Annual Report on Form 10-K.

Warren E. Buffett
Walter Scott, Jr.

Summary Compensation Table

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

Name and Principal Position	Year	Base Salary	Bonus[1]	Non-Equity Incentive Plan Compensation	Change in Pension Value and Nonqualified Deferred Compensation Earnings[2]	All Other Compensation[3]	Total[4]
Gregory E. Abel, Chairman, President	2015	$ 1,000,000	$ 11,500,000	$ 28,000,000	$ —	$ 267,944	40,767,944
and Chief Executive Officer	2014	1,000,000	11,500,000	12,000,000	2,625,000	450,612	27,575,612
	2013	1,000,000	9,500,000	—	—	169,770	10,669,770
Patrick J. Goodman, Executive Vice	2015	460,000	1,672,101	—	—	57,451	2,189,552
President and Chief Financial	2014	450,000	1,717,600	—	1,146,000	46,413	3,360,013
Officer	2013	410,000	1,756,630	—	—	58,502	2,225,132
Natalie L. Hocken, Senior Vice	2015	313,636	810,090	—	—	30,339	1,154,065
President and General Counsel[5]							
Douglas L. Anderson, Chief	2015	350,000	1,011,863	—	3,000	31,351	1,396,214
Corporate Counsel[6]	2014	339,000	1,228,551	—	8,000	30,704	1,606,255
	2013	330,000	1,140,973	—	1,000	30,090	1,502,063
Maureen E. Sammon, President and	2015	297,247	720,058	—	2,000	19,273	1,038,578
Chief Executive Officer,	2014	260,000	686,122	—	9,000	30,140	985,262
HomeServices Mortgage[7]	2013	245,000	666,795	—	1,000	29,450	942,245

(1) Consists of annual cash incentive awards earned pursuant to the PIP for BHE's NEOs, performance awards earned related to non-routine projects, and the vesting of LTIP awards and associated vested earnings. The breakout for 2015 is as follows:

			LTIP		
	PIP	Performance Award	Vested Awards	Vested Earnings	Total
Gregory E. Abel	$ 11,500,000	$ —	$ —	$ —	$ —
Patrick J. Goodman	500,000	250,000	860,000	62,101	922,101
Natalie L. Hocken	400,000	—	341,570	68,520	410,090
Douglas L. Anderson	350,000	—	590,750	71,113	661,863
Maureen E. Sammon	307,916	—	361,457	50,685	412,142

The ultimate payouts of LTIP awards are undeterminable as the amounts to be paid out may increase or decrease depending on investment performance. Net income, the net income target goal and the matrix below were used in determining the gross amount of the LTIP award available to the participants. Net income for determining the award and the award itself are subject to discretionary adjustment by the Chairman and CEO and Compensation Committee. In 2015, the gross award was determined based on the overall achievement of BHE's financial and non-financial objectives.

Net Income	Award
Less than or equal to net income target goal	None
Exceeds net income target goal	33.33% of excess

(2) Amounts are based upon the aggregate increase in the actuarial present value of all qualified and nonqualified defined benefit plans, which include BHE's cash balance and SERP, as applicable. Amounts are computed using assumptions consistent with those used in preparing the related pension disclosures in the Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K and are as of December 31, 2015. No participant in BHE's DCPs earned "above-market" or "preferential" earnings on amounts deferred.

(3) Amounts consist of 401(k) contributions BHE paid on behalf of the NEOs, as well as perquisites and other personal benefits related to life insurance premiums, the personal use of corporate aircraft and financial planning and tax preparation that BHE paid on behalf of Messrs. Abel, Goodman and Anderson. The personal use of corporate aircraft represents BHE's incremental cost of providing this personal benefit determined by applying the percentage of flight hours used for personal use to BHE's incremental expenses incurred from operating its corporate aircraft, partially offset by reimbursed costs by the NEO. All other compensation is based upon amounts paid by BHE.

Items required to be reported and quantified are as follows: Mr. Abel - personal use of corporate aircraft of $207,379 and 401(k) contributions of $12,853; Mr. Goodman - 401(k) contributions of $30,078; Ms. Hocken - 401(k) contributions of $29,839; Mr. Anderson - 401(k) contributions of $30,078; and Ms. Sammon - 401(k) contributions of $18,733.

(4) Any amounts voluntarily deferred by the NEO, if applicable, are included in the appropriate column in the summary compensation table.

(5) Ms. Hocken was named Senior Vice President and General Counsel effective July 10, 2015. Ms. Hocken was previously the Senior Vice President, Transmission and System Operations at PacifiCorp, an indirect, wholly owned subsidiary of BHE's.

(6) Mr. Anderson served as Executive Vice President and General Counsel through July 9, 2015.

(7) Ms. Sammon served as Senior Vice President and Chief Administrative Officer through July 31, 2015.

Pension Benefits

The following table sets forth certain information regarding the defined benefit pension plan accounts held by each of BHE's NEOs as of December 31, 2015:

Name	Plan name	Number of years credited service[1]	Present value of accumulated benefit[2]	Payments during last fiscal year
Gregory E. Abel	SERP	n/a	$ 10,269,000	$ —
	MidAmerican Energy Company Retirement Plan	17 years	328,000	—
Patrick J. Goodman	SERP	21 years	3,280,000	—
	MidAmerican Energy Company Retirement Plan	10 years	214,000	—
Natalie L. Hocken	PacifiCorp Retirement Plan	7 years	95,000	—
Douglas L. Anderson	MidAmerican Energy Company Retirement Plan	10 years	225,000	—
Maureen E. Sammon	MidAmerican Energy Company Retirement Plan	22 years	249,000	—

(1) Mr. Goodman's credited years of service, for purposes of the SERP only, includes 17 years of service with BHE and four additional years of imputed service from a predecessor company.

(2) Amounts are computed using assumptions consistent with those used in preparing the related pension disclosures in Notes to Consolidated Financial Statements of Berkshire Hathaway Energy in Item 8 of this Form 10-K and are as of December 31, 2015, which is the measurement date for the plans. The present value of accumulated benefits for the SERP was calculated using the following form of payment assumptions: (1) Mr. Abel - a 100% joint and survivor annuity and (2) Mr. Goodman - a 66 2/3% joint and survivor annuity. The present value of accumulated benefits for the MidAmerican Energy Company Retirement Plan was calculated using a 90% lump sum payment and a 10% single life annuity. The present value assumptions used in calculating the present value of accumulated benefits for both the SERP and the MidAmerican Energy Company Retirement Plan were as follows: a cash balance interest crediting rate of 1.18% in 2016 and 2017 and 3.50% thereafter; a cash balance conversion rate of 4.50% in 2015 and thereafter; a discount rate of 4.50%; an expected retirement age of 65; and postretirement mortality and cash balance conversion mortality based on the RP-2014 mortality tables, translated to 2011 using scale MP-2014 and loaded 3% for credibility-weighted experience, with custom RPEC-2014 generational improvements.

The present value of accumulated benefits for the PacifiCorp Retirement Plan was calculated using the following assumptions: 50% lump sum payment, 35% joint and 100% survivor annuity and 15% single life annuity; a discount rate of 4.40%; an expected retirement age of 65; postretirement mortality and lump sum conversion mortality based on the RP-2014 mortality tables, translated to 2011 using scale MP-2014 and loaded 3% for credibility-weighted experience, with custom RPEC-2014 generational improvements; and a lump sum interest rate of 4.40%.

The SERP provides annual retirement benefits up to 65% of a participant's total cash compensation in effect immediately prior to retirement, subject to an annual $1 million maximum retirement benefit. Total cash compensation means (i) the highest amount payable to a participant as monthly base salary during the five years immediately prior to retirement multiplied by 12, plus (ii) the average of the participant's awards under an annual incentive bonus program during the three years immediately prior to the year of retirement and (iii) special, additional or non-recurring bonus awards, if any, that are required to be included in total cash compensation pursuant to a participant's employment agreement or approved for inclusion by the Board of Directors. Mr. Goodman's SERP benefit will be reduced by the amount of his regular retirement benefit under the MidAmerican Energy Company Retirement Plan, his actuarially equivalent benefit under the fixed 401(k) contribution option and ratably for retirement between ages 55 and 65. A survivor benefit is payable to a surviving spouse under the SERP. Benefits from the SERP will be paid out of general corporate funds; however, through a Rabbi trust, BHE maintains life insurance on participants in amounts expected to be sufficient to fund the after-tax cost of the projected benefits. Deferred compensation is considered part of the salary covered by the SERP.

Under the MidAmerican Energy Company Retirement Plan, each NEO (except Ms. Hocken, who participates in the PacifiCorp Retirement Plan as described below) has an account, for record-keeping purposes only, to which credits are allocated annually based upon a percentage of the NEO's base salary and incentive paid in the plan year. In addition, all balances in the accounts of NEOs earn a fixed rate of interest that is credited annually. The interest rate for a particular year is based on the one-year constant maturity Treasury yield plus seven-tenths of one percentage point. Each NEO is vested in the MidAmerican Energy Company Retirement Plan. At retirement, or other termination of employment, an amount equal to the vested balance then credited to the account is payable to the NEO in the form of a lump sum or an annuity.

PacifiCorp adopted the PacifiCorp Retirement Plan for employees not subject to collective bargaining agreements that do not provide for participation in the PacifiCorp 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. Pay for this purpose included base salary and annual incentive plan payments up to 10% of base salary, but was limited to the amounts specified in Internal Revenue Code 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)) multiplied by years of service.

The PacifiCorp 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. Benefits under the final average pay formula were frozen as of May 31, 2007, and no future benefits will accrue under that formula. 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 PacifiCorp Retirement Plan restatement.

Participants in the PacifiCorp 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.

In 2008, non-union employee participants in the MidAmerican Energy Company Retirement Plan and the PacifiCorp Retirement Plan were offered the option to continue to receive pay credits in the MidAmerican Energy Company Retirement Plan and the PacifiCorp Retirement Plan or receive equivalent fixed contributions to the MidAmerican Energy Company Retirement Savings Plan and the PacifiCorp K Plus Employee Savings Plan, or 401(k) plans, with any such election becoming effective January 1, 2009. Messrs. Goodman and Anderson and Mses. Hocken and Sammon elected the equivalent fixed 401(k) contribution option and, therefore, no longer receive pay credits in the MidAmerican Energy Company Retirement Plan and the PacifiCorp 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 BHE's NEOs as of December 31, 2015:

Name	Executive contributions in 2015[1]	Registrant contributions in 2015	Aggregate earnings in 2015	Aggregate withdrawals/ distributions	Aggregate balance as of December 31, 2015[2][3]
Gregory E. Abel	$ —	$ —	$ (16,233)	$ (657,338)	$ 2,237,176
Patrick J. Goodman	—	—	(14,026)	—	1,481,830
Natalie L. Hocken	—	—	(2,266)	—	1,335,875
Douglas L. Anderson	458,673	—	(21,216)	(143,281)	5,298,249
Maureen E. Sammon	—	—	(30,906)	—	3,171,744

(1) The contribution amount shown for Mr. Anderson includes $341,992 earned from his 2011 LTIP award prior to 2015. Therefore, that amount is not included in the 2015 total compensation reported for him in the Summary Compensation Table.

(2) The aggregate balance as of December 31, 2015 shown for Mr. Anderson and Ms. Sammon includes $504,287 and $140,467, respectively, of compensation previously reported in 2014 in the Summary Compensation Table and $414,975 and $212,492, respectively, of compensation previously reported in 2013 in the Summary Compensation Table.

(3) Excludes the value of 10,041 shares of BHE common stock reserved for issuance to Mr. Abel. Mr. Abel deferred the right to receive the value of these shares pursuant to a legacy nonqualified deferred compensation plan.

Eligibility for BHE's DCPs 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 DCPs permit 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 DCPs 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 DCPs allow 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. 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 BHE's LTIP also have the option of deferring all or a part of those awards after the four-year mandatory deferral and vesting period. The provisions governing the deferral of LTIP awards are similar to those described for the DCPs above.

Potential Payments Upon Termination

BHE has entered into employment agreements with Messrs. Abel and Goodman that provide for payments following termination of employment under various circumstances, which do not include change-in-control provisions.

A termination of employment of either Messrs. Abel or Goodman will occur upon their respective resignation (with or without good reason), permanent disability, death, or termination by BHE with or without cause.

The employment agreement for Mr. Abel also includes provisions specific to the calculation of his SERP benefit.

Neither Mr. Anderson nor Mses. Hocken or Sammon has an employment agreement. Where a NEO does not have an employment agreement, or in the event that the agreements for Messrs. Abel and Goodman do not address an issue, payments upon termination are determined by the applicable plan documents and BHE's general employment policies and practices as discussed below.

The following discussion provides further detail on post-termination payments.

Gregory E. Abel

Mr. Abel's employment agreement entitles him to receive two years base salary continuation and payments in respect of average bonuses for the prior two years in the event BHE terminates his employment other than for cause. The payments are to be paid as a lump sum with no discount for present valuation.

In addition, if Mr. Abel's employment is terminated due to death, permanent disability or other than for cause, he is entitled to continuation of his senior executive employee benefits (or the economic equivalent thereof) for two years. If Mr. Abel resigns, BHE must pay him any accrued but unpaid base salary, unless he resigns for good reason, in which case he will receive the same benefits as if he were terminated other than for cause.

Payments made in accordance with the employment agreement are contingent on Mr. Abel complying with the confidentiality and post-employment restrictions described therein. The term of the agreement effectively expires on August 6, 2020, and is extended automatically for additional one year terms thereafter subject to Mr. Abel's election to decline renewal at least 365 days prior to the August 6 that is four years prior to the current expiration date (or by August 6, 2016, for the agreement not to extend to August 6, 2021).

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, including 401(k) and nonqualified deferred compensation account balances and those portions of life insurance benefits and cash balance pension amounts that would have otherwise been paid, are not included herein. All estimated payments reflected in the table below assume termination on December 31, 2015, and are payable as lump sums unless otherwise noted.

Termination Scenario	Cash Severance(1)	Incentive	Life Insurance(2)	Pension(3)	Benefits Continuation(4)	Excise and Other Taxes(5)
Retirement, Voluntary and Involuntary With Cause	$ —	$ —	$ —	$ 8,915,000	$ —	$ —
Involuntary Without Cause, Disability and Voluntary With Good Reason	25,000,000	—	—	8,915,000	79,454	—
Death	25,000,000	—	1,885,350	8,284,000	79,454	—

(1) The cash severance payments are determined in accordance with Mr. Abel's employment agreement.

(2) Life insurance benefits are equal to two times base salary, as of the preceding June 1, less the benefits otherwise payable in all other termination scenarios, which are equal to the total cash value of the policies less cumulative premiums paid by BHE.

(3) 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. Mr. Abel's death scenario is based on a 100% joint and survivor with 15-year certain annuity commencing immediately. Mr. Abel's other termination scenarios are based on a 100% joint and survivor annuity commencing immediately.

(4) Includes health and welfare, life insurance and financial planning and tax preparation benefits for two years. The health and welfare benefit amounts are estimated using the rates BHE currently charges employees terminating employment but electing to continue their medical, dental and vision insurance after termination. These amounts are grossed-up for taxes and then reduced by the amount Mr. Abel would have paid if he had continued his employment. The life insurance benefit amounts are based on the cost of individual policies offering benefits equivalent to BHE's group coverage and are grossed-up for taxes. These amounts also assume benefit continuation for the entire two year period, with no offset by another employer. BHE will also continue to provide financial planning and tax preparation reimbursement, or the economic equivalent thereof, for two years or pay a lump sum cash amount to keep Mr. Abel in the same economic position on an after-tax basis. The amount included is based on an annual estimated cost using the most recent three-year average annual reimbursement. If it is determined that benefits paid with respect to the extension of medical and dental benefits to Mr. Abel would not be exempt from taxation under the Internal Revenue Code, BHE shall pay to Mr. Abel a lump sum cash payment following separation from service to allow him to obtain equivalent medical and dental benefits and which would put him in the same after-tax economic position.

(5) As provided in Mr. Abel's employment agreement, should it be deemed under Section 280G of the Internal Revenue Code that termination payments constitute excess parachute payments subject to an excise tax, BHE will gross up such payments to cover the excise tax and any additional taxes associated with such gross-up. Based on computations prescribed under Section 280G and related regulations, BHE does not believe that any of the termination scenarios are subject to any excise tax.

Patrick J. Goodman

Mr. Goodman's employment agreement entitles him to receive two years base salary continuation and payments in respect of average bonuses for the prior two years in the event BHE terminates his employment other than for cause. The payments are to be paid as a lump sum with no discount for present valuation.

In addition, if Mr. Goodman's employment is terminated due to death, permanent disability or other than for cause, he is entitled to continuation of his senior executive employee benefits (or the economic equivalent thereof) for one year. If Mr. Goodman resigns, BHE must pay him any accrued but unpaid base salary, unless he resigns for good reason, in which case he will receive the same benefits as if he were terminated other than for cause.

Payments made in accordance with the employment agreement are contingent on Mr. Goodman complying with the confidentiality and post-employment restrictions described therein. The term of the agreement expires on April 21, 2017, but is extended automatically for additional one year terms thereafter subject to Mr. Goodman's election to decline renewal at least 365 days prior to the then current expiration date or termination.

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, including 401(k) and nonqualified deferred compensation account balances and those portions of long-term incentive payments, life insurance benefits and cash balance pension amounts that would have otherwise been paid, are not included herein. All estimated payments reflected in the table below assume termination on December 31, 2015, and are payable as lump sums unless otherwise noted.

Termination Scenario	Cash Severance(1)	Incentive(2)	Life Insurance(3)	Pension(4)	Benefits Continuation(5)	Excise and Other Taxes(6)
Retirement and Voluntary	$ —	$ —	$ —	$ 1,865,000	$ —	$ —
Involuntary With Cause	—	—	—	—	—	—
Involuntary Without Cause and Voluntary With Good Reason	4,085,500	—	—	1,865,000	24,028	—
Death	4,085,500	1,713,721	899,947	3,403,000	24,028	—
Disability	4,085,500	1,713,721	—	3,426,000	24,028	—

(1) The cash severance payments are determined in accordance with Mr. Goodman's employment agreement.

(2) Amounts represent the unvested portion of Mr. Goodman's LTIP account, which becomes 100% vested upon his death or disability.

(3) Life insurance benefits are equal to two times base salary, as of the preceding June 1, less the benefits otherwise payable in all other termination scenarios, which are equal to the total cash value of the policies less cumulative premiums paid by BHE.

(4) 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. Mr. Goodman's voluntary termination, retirement, involuntary without cause, and change in control termination scenarios are based on a 66 2/3% joint and survivor annuity commencing at age 55 (reductions for termination prior to age 55 and commencement prior to age 65). Mr. Goodman's disability scenario is based on a 66 2/3% joint and survivor annuity commencing at age 55 (no reduction for termination prior to age 55, reduced for commencement prior to age 65). Mr. Goodman's death scenario is based on a 15-year certain only annuity commencing immediately (no reduction for termination prior to age 55 and commencement prior to age 65).

(5) Includes health and welfare, life insurance and financial planning and tax preparation benefits for one year. The health and welfare benefit amounts are estimated using the rates BHE currently charges employees terminating employment but electing to continue their medical, dental and vision insurance after termination. These amounts are grossed-up for taxes and then reduced by the amount Mr. Goodman would have paid if he had continued his employment. The life insurance benefit amounts are based on the cost of individual policies offering benefits equivalent to BHE's group coverage and are grossed-up for taxes. These amounts also assume benefit continuation for the entire one year period, with no offset by another employer. BHE will also continue to provide financial planning and tax preparation reimbursement, or the economic equivalent thereof, for one year or pay a lump sum cash amount to keep Mr. Goodman in the same economic position on an after-tax basis. The amount included is based on an annual estimated cost using the most recent three-year average annual reimbursement.

(6) As provided in Mr. Goodman's employment agreement, should it be deemed under Section 280G of the Internal Revenue Code that termination payments constitute excess parachute payments subject to an excise tax, BHE will gross up such payments to cover the excise tax and any additional taxes associated with such gross-up. Based on computations prescribed under Section 280G and related regulations, BHE does not believe that any of the termination scenarios are subject to any excise tax.

Natalie L. Hocken

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, including 401(k) and nonqualified deferred compensation account balances and those portions of long-term incentive payments and cash balance pension amounts that would have otherwise been paid, are not included herein. All estimated payments reflected in the table below assume termination on December 31, 2015, and are payable as lump sums unless otherwise noted.

Termination Scenario	Cash Severance	Incentive[1]	Life Insurance	Pension[2]	Benefits Continuation	Excise and Other Taxes
Retirement, Voluntary and Involuntary With or Without Cause	$ —	$ —	$ —	$ 2,000	$ —	$ —
Death and Disability	—	796,186	—	2,000	—	—

(1) Amounts represent the unvested portion of Ms. Hocken's LTIP account, which becomes 100% vested upon her 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.

Douglas L. Anderson

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, including 401(k) and nonqualified deferred compensation account balances and those portions of long-term incentive payments and cash balance pension amounts that would have otherwise been paid, are not included herein. All estimated payments reflected in the table below assume termination on December 31, 2015, and are payable as lump sums unless otherwise noted.

Termination Scenario	Cash Severance	Incentive[1]	Life Insurance	Pension[2]	Benefits Continuation	Excise and Other Taxes
Retirement, Voluntary and Involuntary With or Without Cause	$ —	$ —	$ —	$ 27,000	$ —	$ —
Death and Disability	—	1,318,679	—	27,000	—	—

(1) Amounts represent the unvested portion of Mr. Anderson's LTIP account, which becomes 100% vested upon his 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.

Maureen E. Sammon

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, including 401(k) and nonqualified deferred compensation account balances and those portions of long-term incentive payments and cash balance pension amounts that would have otherwise been paid, are not included herein. All estimated payments reflected in the table below assume termination on December 31, 2015, and are payable as lump sums unless otherwise noted.

Termination Scenario	Cash Severance	Incentive(1)	Life Insurance	Pension(2)	Benefits Continuation	Excise and Other Taxes
Retirement, Voluntary and Involuntary With or Without Cause	$ —	$ —	$ —	$ 46,000	$ —	$ —
Death and Disability	—	856,763	—	46,000	—	—

(1) Amounts represent the unvested portion of Ms. Sammon's LTIP account, which becomes 100% vested upon her 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.

Director Compensation

BHE's directors are not paid any fees for serving as directors. All directors are reimbursed for their expenses incurred in attending Board of Directors meetings.

Compensation Committee Interlocks and Insider Participation

Mr. Buffett is the Chairman of the Board of Directors and Chief Executive Officer of Berkshire Hathaway, BHE's majority owner. Mr. Scott is a former officer of BHE. Based on the standards of the New York Stock Exchange LLC, on which the common stock of BHE's majority owner, Berkshire Hathaway, is listed, BHE's Board of Directors has determined that Messrs. Buffett and Scott are not independent because of their ownership of BHE common stock. None of BHE's executive officers serves as a member of the compensation committee of any company that has an executive officer serving as a member of BHE's Board of Directors. None of BHE's executive officers serves as a member of the board of directors of any company that has an executive officer serving as a member of BHE's Compensation Committee. See also Berkshire Hathaway Energy's Item 13 in this Annual Report on Form 10-K.

PACIFICORP

Compensation Discussion and Analysis

Compensation Philosophy and Overall Objectives

Mr. Gregory E. Abel, PacifiCorp's Chairman of the Board of Directors and Chief Executive Officer, or Chairman and CEO, receives no direct compensation from PacifiCorp. PacifiCorp reimburses its indirect parent company, BHE, for the cost of Mr. Abel's time spent on matters supporting PacifiCorp, including compensation paid to him by BHE, pursuant to an intercompany administrative services agreement among BHE and its subsidiaries. Please refer to Berkshire Hathaway Energy's Item 11 in this Annual Report on Form 10-K for executive compensation and post-termination payment information for Mr. Abel.

PacifiCorp believes that the compensation paid to each of its Chief Financial Officer, or CFO, and its other most highly compensated executive officers, to whom PacifiCorp refers collectively as its Named Executive Officers, or NEOs, should be closely aligned with its 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 the organization. PacifiCorp's compensation programs are designed to provide its 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 PacifiCorp believes contribute to its long-term success.

How is Compensation Determined

PacifiCorp's 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 PacifiCorp's compensation policy and for approving compensation decisions for its NEOs such as approving base pay increases, incentive and performance awards, off-cycle pay changes, and participation in other employee benefit plans and programs.

PacifiCorp's 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. PacifiCorp does not specifically use other companies as benchmarks when establishing its NEOs' compensation.

Discussion and Analysis of Specific Compensation Elements

Base Salary

PacifiCorp determines base salaries for all of its NEOs, other than Mr. Abel, by reviewing its overall performance, and each NEO's performance, the value each NEO brings to PacifiCorp 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. For 2015, base salaries for all NEOs, other than Mr. Abel and Ms. Crane, increased on average by 2.5% effective December 26, 2014, reflecting merit increases. Base salaries for Mr. Bird and Ms. Kobliha were also increased during 2015 in connection with their respective promotions. Ms. Crane's base salary increased during 2015 in connection with her assuming additional responsibilities.

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 PacifiCorp's 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, PacifiCorp's overall performance and each NEO's contribution to that overall performance. Mr. Abel evaluates performance using financial and non-financial objectives, including customer service, employee commitment and safety, environmental respect, regulatory integrity, operational excellence and financial strength, 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 2015. Approved awards are paid prior to year-end.

Performance Awards

In addition to the annual awards under the AIP, PacifiCorp 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. PacifiCorp's current long-term incentive compensation program is cash-based. PacifiCorp does 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 PacifiCorp's interests and the interests of the participating employees. All of PacifiCorp's 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 approve 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 four-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 four-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.

Deferred Compensation Plan

PacifiCorp's 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. PacifiCorp includes 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 PacifiCorp to make discretionary contributions on behalf of participants.

Potential Payments Upon Termination

PacifiCorp's 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, PacifiCorp's other NEOs would be entitled to the vested balances in the LTIP, DCP and PacifiCorp's non-contributory defined benefit pension plan, or the Retirement Plan.

Compensation Committee Report

Mr. Abel, PacifiCorp's Chairman and CEO and sole member of PacifiCorp's 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 PacifiCorp's 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)	2015	$ —	$ —	$ —	$ —	$ —
Chairman and	2014	—	—	—	—	—
Chief Executive Officer	2013	—	—	—	—	—
Stefan A. Bird(6)	2015	313,275	844,634	13,201	12,614	1,183,724
President and Chief Executive	2014	—	—	—	—	—
Officer, Pacific Power	2013	—	—	—	—	—
Cindy A. Crane	2015	324,028	758,656	8,589	13,429	1,104,702
President and Chief Executive	2014	224,538	580,950	79,542	73,838	958,868
Officer, Rocky Mountain Power	2013	—	—	—	—	—
R. Patrick Reiten	2015	330,000	898,935	—	25,864	1,254,799
President and Chief Executive	2014	320,000	1,167,125	822	25,980	1,513,927
Officer, PacifiCorp Transmission	2013	310,000	1,137,462	3	25,245	1,472,710
Nikki L. Kobliha(7)	2015	177,384	91,758	—	27,253	296,395
Vice President and	2014	—	—	—	—	—
Chief Financial Officer	2013	—	—	—	—	—
Douglas K. Stuver(7)	2015	163,394	213,224	—	12,745	389,363
Senior Vice President and	2014	252,000	421,772	21,443	29,808	725,023
Chief Financial Officer	2013	246,495	415,937	—	28,985	691,417

(1) Consists of annual cash incentive awards earned pursuant to the AIP for PacifiCorp's NEOs, performance awards for Mr. Bird and Ms. Crane in recognition of efforts to support PacifiCorp's objectives and the vesting of LTIP awards and associated vested earnings. The breakout for 2015 is as follows:

			LTIP		
	AIP	Performance Award	Vested Awards	Vested Earnings	Total
Stefan A. Bird	$ 285,000	$ 200,000	$ 331,698	$ 27,936	$ 359,634
Cindy A. Crane	285,000	200,000	241,712	31,944	273,656
R. Patrick Reiten	285,000	—	530,000	83,935	613,935
Nikki L. Kobliha	70,000	—	21,750	8	21,758
Douglas K. Stuver	—	—	193,394	19,830	213,224

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 2015, the gross award was subjectively determined at the discretion of the BHE Chairman and PacifiCorp Presidents based on the overall achievement of PacifiCorp's financial and non-financial objectives including customer service, employee commitment and safety, environmental respect, regulatory integrity, operational excellence and financial strength.

(2) 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 below for a discussion of the assumptions used in calculating these amounts. No participant in PacifiCorp's nonqualified deferred compensation plans earned "above market" or "preferential" earnings on amounts deferred. Negative amounts for the change in pension value not reported in the Summary Compensation Table are as follows: Mr. Reiten $(83); Ms. Kobliha $(5,513); and Mr. Stuver $(2,500).

(3) Amounts consist of PacifiCorp K Plus Employee Savings Plan, or 401(k) Plan, contributions PacifiCorp paid on behalf of the NEOs, except for Ms. Crane for whom PacifiCorp also includes an amount paid to her as a tax gross-up with respect to a personal benefit with a value less than $10,000.

(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 PacifiCorp. PacifiCorp reimburses BHE for the cost of Mr. Abel's time spent on matters supporting PacifiCorp, including compensation paid to him by BHE, pursuant to an intercompany administrative services agreement among BHE and its subsidiaries. Please refer to Berkshire Hathaway Energy's Item 11 in this Annual Report on Form 10-K for executive compensation information for Mr. Abel.

(6) Mr. Bird was elected President and CEO, Pacific Power effective March 10, 2015.

(7) Mr. Stuver resigned as an employee and Senior Vice President and CFO of PacifiCorp effective August 13, 2015. Ms. Kobliha was appointed Vice President and CFO of PacifiCorp effective August 13, 2015 and was elected to that position on October 26, 2015.

Pension Benefits

The following table sets forth certain information regarding the defined benefit pension plan accounts held by each of PacifiCorp's NEOs as of December 31, 2015:

Name	Plan name	Number of years of credited service	Present value of accumulated benefits [(1)]
Gregory E. Abel	n/a	n/a	n/a
Stefan A. Bird	Retirement	9 years	$ 167,116
Cindy A. Crane	Retirement	20 years	397,806
R. Patrick Reiten	Retirement	2 years	16,775
Nikki L. Kobliha	Retirement	12 years	95,763
Douglas K. Stuver[(2)]	Retirement	5 years	—

(1) Amounts are computed using assumptions, other than the expected retirement age, consistent with those used in preparing the related pension disclosures in the Notes to Consolidated Financial Statements of PacifiCorp in Item 8 of this Form 10-K and are as of December 31, 2015, 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. For the Retirement Plan calculations of the present value of accumulated benefits, the following assumptions were used: 50% lump sum payment; 35% joint and 100% survivor annuity; and 15% single life annuity. The present value assumptions used in calculating the present value of accumulated benefits for the Retirement Plan were as follows: a discount rate of 4.40%; an expected retirement age of 65; postretirement mortality and lump sum mortality using the RP-2014 tables (translated to 2011 using scale MP-2014 and adjusted for BHE credibility weighted experience, with custom RPEC-2014 generational improvements); and a lump sum interest rate of 4.40%.

(2) Mr. Stuver received a payout in the amount of $117,097 in connection with his resignation as an employee and Senior Vice President and CFO of PacifiCorp effective August 13, 2015.

PacifiCorp has adopted the Retirement Plan for the majority of its 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. Pay for this purpose included base salary and annual incentive plan payments up to 10% of base salary, but was limited to the amounts specified in Internal Revenue Code 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)) multiplied by 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 Retirement 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.

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. Reiten and Stuver and Ms. Kobliha 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. Mr. Bird and Ms. Crane elected to continue to receive pay credits in the Retirement Plan.

Nonqualified Deferred Compensation

The following table sets forth certain information regarding the nonqualified deferred compensation plan accounts held by each of PacifiCorp's NEOs as of December 31, 2015:

Name	Executive contributions in 2015 (1)	Registrant contributions in 2015	Aggregate earnings in 2015	Aggregate withdrawals/ distributions	Aggregate balance as of December 31, 2015 (2)
Gregory E. Abel	$ —	$ —	$ —	$ —	$ —
Stefan A. Bird	—	—	—	—	—
Cindy A. Crane	458,594	—	16,422	—	1,792,648
R. Patrick Reiten	702,180	—	6,486	—	1,204,910
Nikki L. Kobliha	—	—	—	—	—
Douglas K. Stuver	—	—	431	10,946	—

(1) The executive contribution amount shown for Ms. Crane represents a deferral of $285,000 of her 2015 compensation and her 2011 LTIP award which was deferred in 2015. The $285,000 deferred compensation and $35,937 of the deferred LTIP award are included in the 2015 total compensation reported for her in the Summary Compensation Table and are not additional compensation. The remaining 2011 LTIP award was earned prior to 2015. The executive contribution amount shown for Mr. Reiten represents a deferral of his 2011 LTIP award which was deferred in 2015. Of this amount, $140,149 is included in the 2015 total compensation reported for him in the Summary Compensation Table and is not additional compensation. The remaining 2011 LTIP award was earned prior to 2015.

(2) The aggregate balance as of December 31, 2015 shown for Ms. Crane includes $50,986 of compensation previously reported in 2014 in the Summary Compensation Table.

Eligibility for PacifiCorp's 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 PacifiCorp's LTIP also have the option of deferring all or a part of those awards after the four-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

PacifiCorp's NEOs, other than Mr. Abel, are not generally entitled to severance or enhanced benefits upon termination of employment or change in control. Please refer to Berkshire Hathaway Energy's Item 11 in this Annual Report on Form 10-K 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 for PacifiCorp's NEOs other than PacifiCorp's former CFO. 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, 2015 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	—	—
Stefan A. Bird:		
Retirement, Voluntary and Involuntary With or Without Cause	—	34,703
Death and Disability	634,359	34,703
Cindy A. Crane:		
Retirement, Voluntary and Involuntary With or Without Cause	—	15,532
Death and Disability	567,109	15,532
R. Patrick Reiten:		
Retirement, Voluntary and Involuntary With or Without Cause	—	2,899
Death and Disability	998,150	2,899
Nikki L. Kobliha:		
Retirement, Voluntary and Involuntary With or Without Cause	—	1,816
Death and Disability	65,262	1,816

(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.

In connection with his resignation as an employee and Senior Vice President and CFO of PacifiCorp effective August 13, 2015, Mr. Stuver received a pension payout in the amount of $117,097.

Director Compensation Table

None of PacifiCorp's directors serving in 2015 received additional compensation for service as a director. The following table excludes Messrs. Abel, Bird and Reiten and Ms. Crane, for whom compensation information is described in the Summary Compensation Table, and Messrs. Anderson and Goodman and Ms. Hocken, for whom compensation information is described in Berkshire Hathaway Energy's Item 11 in this Annual Report on Form 10-K.

Name	Change in Pension Value and Nonqualified Deferred Compensation Earnings (1)	All Other Compensation (2)	Total
Micheal G. Dunn(3)	$ 3,303	$ 612,465	$ 615,768
Andrea L. Kelly	5,847	1,048,253	1,054,100

(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 PacifiCorp's nonqualified deferred compensation plans earned "above market" or "preferential" earnings on amounts deferred.

(2) Amounts shown for the year ended December 31, 2015 are as follows:

(i) Base salary in the amounts of $68,750 for Mr. Dunn and $301,098 for Ms. Kelly.

(ii) Contributions to PacifiCorp's 401(k) Plan of $2,681 for Mr. Dunn and $12,614 for Ms. Kelly.

(iii) Relocation expenses of $52,099 plus tax gross-up of $10,934 for Ms. Kelly. Ms. Kelly's relocation expenses were valued based on the amounts actually paid to Ms. Kelly and to relocation companies for relocation services and expenses.

(iii) Annual cash incentive awards earned pursuant to the AIP for PacifiCorp's directors, the vesting of LTIP awards and associated vested earnings for Mr. Dunn and Ms. Kelly. The breakout of AIP and LTIP awards for 2015 is as follows:

		LTIP		
	AIP	Vested Awards	Vested Earnings/ (Losses)	Total
Micheal G. Dunn	$ —	$ 455,000	$ 86,034	$ 541,034
Andrea L. Kelly	350,000	340,571	(19,063)	321,508

(3) Mr. Dunn resigned as a director and employee effective March 2015.

Compensation Committee Interlocks and Insider Participation

Mr. Abel is PacifiCorp's Chairman and CEO and also the Chairman, President and Chief Executive Officer of BHE. None of PacifiCorp's executive officers serves as a member of the compensation committee of any company that has an executive officer serving as a member of PacifiCorp's Board of Directors. None of PacifiCorp's 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 PacifiCorp's compensation committee. See also PacifiCorp's Item 13 in this Annual Report on Form 10-K.

MIDAMERICAN FUNDING, MIDAMERICAN ENERGY, NEVADA POWER AND SIERRA PACIFIC

Information required by Item 11 is omitted pursuant to General Instruction I(2)(c) to Form 10-K.

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

BERKSHIRE HATHAWAY ENERGY

Beneficial Ownership

BHE is a consolidated subsidiary of Berkshire Hathaway. The balance of BHE's common stock is owned by Mr. Scott (along with family members and related entities) and Mr. Abel. The following table sets forth certain information regarding beneficial ownership of BHE's shares of common stock held by each of its directors, executive officers and all of its directors and executive officers as a group as of January 31, 2016:

Name and Address of Beneficial Owner(1)	Number of Shares Beneficially Owned(2)	Percentage Of Class(2)
Berkshire Hathaway(3)	69,602,161	89.94%
Walter Scott, Jr.(4)	4,100,000	5.30%
Gregory E. Abel	740,961	0.96%
Natalie L. Hocken	—	—
Warren E. Buffett(3)(5)	—	—
Patrick J. Goodman	—	—
Marc D. Hamburg(3)(5)	—	—
All directors and executive officers as a group (6 persons)	4,840,961	6.26%

(1) Unless otherwise indicated, each address is c/o Berkshire Hathaway Energy Company at 666 Grand Avenue, 29th Floor, Des Moines, Iowa 50309.

(2) 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.

(3) Such beneficial owner's address is 1440 Kiewit Plaza, Omaha, Nebraska 68131.

(4) Excludes 2,948,022 shares held by family members and family trusts and corporations, or Scott Family Interests, as to which Mr. Scott disclaims beneficial ownership. Mr. Scott's address is 1000 Kiewit Plaza, Omaha, Nebraska 68131.

(5) Excludes 69,602,161 shares of common stock held by Berkshire Hathaway as to which Messrs. Buffett and Hamburg disclaim beneficial ownership.

The following table sets forth certain information regarding beneficial ownership of Class A and Class B shares of Berkshire Hathaway's common stock held by each of BHE's directors, executive officers and all of its directors and executive officers as a group as of January 31, 2016:

Name and Address of Beneficial Owner[(1)]	**Number of Shares Beneficially Owned**[(2)]	**Percentage Of Class**[(2)]
Walter Scott, Jr.[(3)(4)]		
Class A	100	*
Class B	—	—
Gregory E. Abel[(4)]		
Class A	5	*
Class B	2,363	*
Natalie L. Hocken		
Class A	—	—
Class B	—	—
Warren E. Buffett[(5)]		
Class A	308,261	38.1%
Class B	164,785	*
Patrick J. Goodman		
Class A	5	*
Class B	786	*
Marc D. Hamburg[(5)]		
Class A	—	—
Class B	—	—
All directors and executive officers as a group (6 persons)		
Class A	308,371	38.1%
Class B	167,934	*

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

(1) Unless otherwise indicated, each address is c/o Berkshire Hathaway Energy Company at 666 Grand Avenue, 29th Floor, Des Moines, Iowa 50309.

(2) 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.

(3) Does not include 10 Class A shares owned by Mr. Scott's wife. Mr. Scott's address is 1000 Kiewit Plaza, Omaha, Nebraska 68131.

(4) 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 January 31, 2016, Mr. Scott and the Scott Family Interests and Mr. Abel would be entitled to exchange their shares of BHE common stock for either 18,131 and 1,906, respectively, shares of Berkshire Hathaway Class A stock or 27,155,822 and 2,854,901, respectively, 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. Scott and the Scott Family Interests would beneficially own 2.2% of the outstanding shares of Berkshire Hathaway Class A stock or 2.1% of the outstanding shares of Berkshire Hathaway Class B stock, and Mr. Abel would beneficially own less than 1% of the outstanding shares of either class of stock.

(5) Such beneficial owner's address is 1440 Kiewit Plaza, Omaha, Nebraska 68131.

Other Matters

Pursuant to a shareholders' agreement, as amended on December 7, 2005, Mr. Scott or any of the Scott Family Interests and Mr. Abel are able to require Berkshire Hathaway to exchange any or all of their respective 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.

PACIFICORP

Beneficial Ownership

PacifiCorp is a consolidated subsidiary of BHE. PacifiCorp's 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 that, as of January 31, 2016, 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 PacifiCorp's executive officers or directors owns shares of its 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 PacifiCorp's directors, executive officers and all of its directors and executive officers as a group as of January 31, 2016:

	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	*	2,363	*
Douglas L. Anderson	—	—	4	*	300	*
Stefan A. Bird	—	—	—	—	—	—
Cindy A. Crane	—	—	—	—	—	—
Patrick J. Goodman	—	—	5	*	786	*
Natalie L. Hocken	—	—	—	—	—	—
Andrea L. Kelly	—	—	—	—	100	*
Nikki L. Kobliha	—	—	—	—	—	—
R. Patrick Reiten	—	—	—	—	—	—
All executive officers and directors as a group (9 persons)	740,961	0.96%	14	*	3,549	*

* 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 January 31, 2016, Mr. Abel would be entitled to exchange his shares of BHE common stock for either 1,906 shares of Berkshire Hathaway Class A stock or 2,854,901 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.

MIDAMERICAN FUNDING, MIDAMERICAN ENERGY, NEVADA POWER AND SIERRA PACIFIC

Information required by Item 12 is omitted pursuant to General Instruction I(2)(c) to Form 10-K.

Item 13. Certain Relationships and Related Transactions, and Director Independence

BERKSHIRE HATHAWAY ENERGY

Certain Relationships and Related Transactions

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

Under the Codes, all of BHE's directors and executive officers (including those of its subsidiaries) must disclose to BHE's legal department any material transaction or relationship that reasonably could be expected to give rise to a conflict with its interests. No action may be taken with respect to such transaction or relationship until approved by the legal department. For BHE's 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 BHE's interests. Transactions with Berkshire Hathaway require the approval of BHE's Board of Directors.

As of December 31, 2015 and 2014, certain Berkshire Hathaway subsidiaries held variable-rate junior subordinated debentures due from BHE totaling $2.9 billion and $3.8 billion, respectively. Principal repayments on these securities totaled $850 million and $300 million during 2015 and 2014, respectively, and interest expense on these securities totaled $104 million and $78 million during 2015 and 2014, respectively.

Director Independence

Based on the standards of the New York Stock Exchange LLC, on which the common stock of BHE's majority owner, Berkshire Hathaway, is listed, BHE's Board of Directors has determined that none of its directors are considered independent because of their employment by Berkshire Hathaway or BHE or their ownership of BHE's common stock.

PACIFICORP

Certain Relationships and Related Transactions

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

Under the Codes, all of PacifiCorp's directors and executive officers (including those of its subsidiaries) must disclose to PacifiCorp's legal department any material transaction or relationship that reasonably could be expected to give rise to a conflict with its interests. No action may be taken with respect to such transaction or relationship until approved by the legal department. For PacifiCorp's 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 PacifiCorp's interests.

Under an intercompany administrative services agreement PacifiCorp has entered into with BHE and its other subsidiaries, the costs of certain administrative services provided by BHE to PacifiCorp or by PacifiCorp 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 PacifiCorp serves retail customers. PacifiCorp also provides an annual report of all transactions with its affiliates to its state regulatory commissions, who have the authority to refuse recovery in rates for payments PacifiCorp makes to its affiliates deemed to have the effect of subsidizing the separate business activities of BHE or its other subsidiaries.

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

Director Independence

Because PacifiCorp's common stock is indirectly, wholly owned by BHE, its Board of Directors consists of BHE and PacifiCorp employees and PacifiCorp is 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 PacifiCorp's ultimate parent company, Berkshire Hathaway, is listed, its Board of Directors has determined that none of PacifiCorp's directors are considered independent because of their employment by BHE or PacifiCorp.

MIDAMERICAN FUNDING, MIDAMERICAN ENERGY, NEVADA POWER AND SIERRA PACIFIC

Information required by Item 13 is omitted pursuant to General Instruction I(2)(c) to Form 10-K.

Item 14. Principal Accountant Fees and Services

The following table shows the fees paid or accrued by each Registrant 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):

	Berkshire Hathaway Energy	PacifiCorp	MidAmerican Funding	MidAmerican Energy	Nevada Power	Sierra Pacific
2015						
Audit fees(1)	$ 9.3	$ 1.7	$ 1.2	$ 1.1	$ 0.9	$ 0.9
Audit-related fees(2)	0.9	0.3	0.2	0.1	—	—
Tax fees(3)	0.1	—	—	—	—	—
Total	$ 10.3	$ 2.0	$ 1.4	$ 1.2	$ 0.9	$ 0.9
2014						
Audit fees(1)	$ 9.0	$ 1.5	$ 1.1	$ 1.0	$ 0.9	$ 0.9
Audit-related fees(2)	0.8	0.2	0.1	0.1	—	—
Tax fees(3)	0.2	—	—	—	—	—
Total	$ 10.0	$ 1.7	$ 1.2	$ 1.1	$ 0.9	$ 0.9

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

(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, state and international tax compliance, tax return preparation and tax audits.

The audit committee has considered whether the non-audit services provided to the Registrants 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. The policy provides guidelines for the audit, audit-related, tax and other non-audit services that may be provided by the Deloitte Entities to the Registrants. The policy (a) identifies the guiding principles that must be considered by the audit committee 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 will be submitted to the audit committee by both the Registrants' 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 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. The audit committee 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

(ii) Financial Statement Schedules

Schedules not listed above 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

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

Berkshire Hathaway Energy Company
Parent Company Only
Condensed Balance Sheets
As of December 31,
(Amounts in millions)

	2015	2014
ASSETS		
Current assets:		
Cash and cash equivalents	$ 23	$ 3
Accounts receivable	16	22
Income tax receivable	167	152
Other current assets	2	1
Total current assets	208	178
Investments in subsidiaries	32,505	31,968
Other investments	1,389	1,038
Goodwill	1,221	1,221
Other assets	1,340	1,176
Total assets	$ 36,663	$ 35,581
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and other current liabilities	$ 306	$ 308
Short-term debt	253	395
Total current liabilities	559	703
BHE senior debt	7,814	7,810
BHE junior subordinated debentures	2,944	3,794
Notes payable - affiliate	1,985	1,981
Other long-term liabilities	946	839
Total liabilities	14,248	15,127
Equity:		
BHE shareholders' equity:		
Common stock - 115 shares authorized, no par value, 77 shares issued and outstanding	—	—
Additional paid-in capital	6,403	6,423
Retained earnings	16,906	14,513
Accumulated other comprehensive loss, net	(908)	(494)
Total BHE shareholders' equity	22,401	20,442
Noncontrolling interest	14	12
Total equity	22,415	20,454
Total liabilities and equity	$ 36,663	$ 35,581

The accompanying notes are an integral part of this financial statement schedule.

Schedule I

Berkshire Hathaway Energy Company
Parent Company Only (continued)
Condensed Statements of Operations
For the years ended December 31,
(Amounts in millions)

	2015	2014	2013
Operating costs and expenses:			
General and administration	$ 58	$ 51	$ 64
Depreciation and amortization	3	3	1
Total operating costs and expenses	61	54	65
Operating loss	(61)	(54)	(65)
Other income (expense):			
Interest expense	(556)	(476)	(347)
Other, net	14	4	25
Total other income (expense)	(542)	(472)	(322)
Loss before income tax benefit and equity income	(603)	(526)	(387)
Income tax benefit	(330)	(221)	(345)
Equity income	2,646	2,402	1,679
Net income	2,373	2,097	1,637
Net income attributable to noncontrolling interest	3	2	1
Net income attributable to BHE shareholders	$ 2,370	$ 2,095	$ 1,636

The accompanying notes are an integral part of this financial statement schedule.

Berkshire Hathaway Energy Company
Parent Company Only (continued)
Condensed Statements of Comprehensive Income
For the years ended December 31,
(Amounts in millions)

	2015	2014	2013
Net income	$ 2,373	$ 2,097	$ 1,637
Other comprehensive (loss) income, net of tax	(414)	(397)	366
Comprehensive income	1,959	1,700	2,003
Comprehensive income attributable to noncontrolling interests	3	2	1
Comprehensive income attributable to BHE shareholders	$ 1,956	$ 1,698	$ 2,002

The accompanying notes are an integral part of this financial statement schedule.

Berkshire Hathaway Energy Company
Parent Company Only (continued)
Condensed Statements of Cash Flows
For the years ended December 31,
(Amounts in millions)

	2015	2014	2013
Cash flows from operating activities	$ 2,528	$ 1,937	$ 2,295
Cash flows from investing activities:			
Investments in subsidiaries	(1,506)	(4,937)	(6,522)
Purchases of investments	(36)	(56)	(106)
Proceeds from sale of investments	47	35	89
Notes receivable from affiliate, net	19	(55)	(37)
Other, net	(7)	(7)	(16)
Net cash flows from investing activities	(1,483)	(5,020)	(6,592)
Cash flows from financing activities:			
Proceeds from BHE senior debt	—	1,478	1,981
Proceeds from BHE junior subordinated debentures	—	1,500	2,594
Proceeds from issuance of BHE common stock	—	—	1,000
Repayments of BHE senior debt	—	(250)	—
Repayments of BHE subordinated debt	(850)	(300)	—
Common stock purchases	(36)	—	—
Net (repayments of) proceeds from short-term debt	(142)	395	(825)
Notes payable to affiliate, net	4	(30)	(173)
Other, net	(1)	1	(1)
Net cash flows from financing activities	(1,025)	2,794	4,576
Net change in cash and cash equivalents	20	(289)	279
Cash and cash equivalents at beginning of year	3	292	13
Cash and cash equivalents at end of year	$ 23	$ 3	$ 292

The accompanying notes are an integral part of this financial statement schedule.

BERKSHIRE HATHAWAY ENERGY COMPANY
NOTES TO CONDENSED FINANCIAL STATEMENTS

Basis of Presentation - The condensed financial information of BHE investments in subsidiaries are presented under the equity method of accounting. Under this method, the assets and liabilities of subsidiaries are not consolidated. The investments in subsidiaries are recorded in the Condensed Balance Sheets. The income from operations of subsidiaries is reported on a net basis as equity income in the Condensed Statements of Operations.

Other investments - BHE's investment in BYD Company Limited ("BYD") common stock is accounted for as an available-for-sale security with changes in fair value recognized in AOCI. As of December 31, 2015 and 2014, the fair value of BHE's investment in BYD common stock was $1.2 billion and $881 million, respectively, which resulted in a unrealized gain of $1.0 billion and $649 million as of December 31, 2015 and 2014, respectively.

Dividends and distributions from subsidiaries - Cash dividends paid to BHE by its subsidiaries for the years ended December 31, 2015, 2014 and 2013 were $3.0 billion, $2.3 billion and $2.5 billion, respectively. In January and February 2016, BHE received cash dividends from its subsidiaries totaling $187 million.

Guarantees and commitments - BHE has issued guarantees up to a maximum of $92 million in support of various obligations of consolidated subsidiaries and commitments to provide equity contributions in support of renewable tax equity investments totaling $478 million.

See the notes to the consolidated BHE financial statements in Part II, Item 8 for other disclosures regarding long-term obligations (Notes 8, 9 and 10) and shareholders' equity (Note 17).

Schedule II

BERKSHIRE HATHAWAY ENERGY COMPANY
CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
FOR THE THREE YEARS ENDED DECEMBER 31, 2015
(Amounts in millions)

Column A	Column B	Column C			Column E
Description	Balance at Beginning of Year	Charged to Income	Acquisition Reserves[1]	Column D Deductions	Balance at End of Year
Reserves Deducted From Assets To Which They Apply:					
Reserve for uncollectible accounts receivable:					
Year ended 2015	$ 37	$ 33	$ —	$ (39)	$ 31
Year ended 2014	33	37	—	(33)	37
Year ended 2013	22	23	9	(21)	33
Reserves Not Deducted From Assets[2]:					
Year ended 2015	$ 11	$ 7	$ —	$ (5)	$ 13
Year ended 2014	9	12	—	(10)	11
Year ended 2013	9	6	—	(6)	9

The notes to the consolidated BHE financial statements are an integral part of this financial statement schedule.

(1) Acquisition reserves represent the reserves recorded at NV Energy, Inc. at the date of acquisition.

(2) Reserves not deducted from assets relate primarily to estimated liabilities for losses retained by BHE for workers compensation, public liability and property damage claims.

MIDAMERICAN FUNDING, LLC
PARENT COMPANY ONLY
CONDENSED BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2015	**2014**
ASSETS		
Current assets:		
Receivables from affiliates	$ 2	$ 2
Investments in and advances to subsidiaries	6,144	5,679
Total assets	$ 6,146	$ 5,681
LIABILITIES AND MEMBER'S EQUITY		
Current liabilities:		
Interest accrued and other current liabilities	$ 7	$ 8
Payable to affiliate	288	274
Long-term debt	326	326
Total liabilities	621	608
Member's equity:		
Paid-in capital	1,679	1,679
Retained earnings	3,876	3,417
Accumulated other comprehensive loss, net	(30)	(23)
Total member's equity	5,525	5,073
Total liabilities and member's equity	$ 6,146	$ 5,681

The accompanying notes are an integral part of this financial statement schedule.

MIDAMERICAN FUNDING, LLC
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2015	2014	2013
Interest expense	$ 22	$ 22	$ 22
Loss before income taxes	(22)	(22)	(22)
Income tax benefit	(8)	(9)	(9)
Equity in undistributed earnings of subsidiaries	472	422	353
Net income	$ 458	$ 409	$ 340

The accompanying notes are an integral part of this financial statement schedule.

MIDAMERICAN FUNDING, LLC
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME
(Amounts in millions)

	Years Ended December 31,		
	2015	2014	2013
Net income	$ 458	$ 409	$ 340
Total other comprehensive (loss) income, net of tax	(7)	(12)	13
Comprehensive income	$ 451	$ 397	$ 353

The accompanying notes are an integral part of this financial statement schedule.

MIDAMERICAN FUNDING, LLC
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF CASH FLOWS
(In millions)

	Years Ended December 31,		
	2015	**2014**	**2013**
Net cash flows from operating activities	$ (13)	$ (13)	$ (13)
Net cash flows from investing activities	—	—	—
Net cash flows from financing activities:			
Net change in amounts payable to subsidiary	13	13	13
Net cash flows from financing activities	13	13	13
Net change in cash and cash equivalents	—	—	—
Cash and cash equivalents at beginning of year	—	—	—
Cash and cash equivalents at end of year	$ —	$ —	$ —

The accompanying notes are an integral part of this financial statement schedule.

MIDAMERICAN FUNDING, LLC
PARENT COMPANY ONLY
NOTES TO CONDENSED FINANCIAL STATEMENTS

Incorporated by reference are MidAmerican Funding, LLC and Subsidiaries Consolidated Statements of Changes in Equity for the three years ended December 31, 2015 in Part II, Item 8.

Basis of Presentation - The condensed financial information of MidAmerican Funding, LLC's ("MidAmerican Funding's") investments in subsidiaries is presented under the equity method of accounting. Under this method, the assets and liabilities of subsidiaries are not consolidated. The investments in and advances to subsidiaries are recorded on the Condensed Balance Sheets. The income from operations of the subsidiaries is reported on a net basis as equity in undistributed earnings of subsidiary companies on the Condensed Statements of Operations.

Payable to Affiliate - MHC, Inc. ("MHC") settles all obligations of MidAmerican Funding including primarily interest costs on, and repayments of, MidAmerican Funding's long-term debt. Net amounts paid by MHC on behalf of MidAmerican Funding totaled $13 million, $13 million and $13 million for the years 2015, 2014 and 2013, respectively.

See the notes to the consolidated MidAmerican Funding financial statements in Part II, Item 8 for other disclosures.

MHC INC.
PARENT COMPANY ONLY
CONDENSED BALANCE SHEETS
(Amounts in millions)

	As of December 31,	
	2015	**2014**
ASSETS		
Current assets:		
Cash and cash equivalents	$ —	$ 1
Receivables from affiliates	1	1
Receivable from parent	288	274
Investments and nonregulated property, net	12	13
Goodwill	1,270	1,270
Investments in and advances to subsidiaries	4,724	4,275
Total assets	$ 6,295	$ 5,834
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Payables to affiliates	$ 146	$ 150
Deferred income taxes	5	5
Total liabilities	151	155
Shareholder's equity:		
Paid-in capital	2,430	2,430
Retained earnings	3,744	3,272
Accumulated other comprehensive loss, net	(30)	(23)
Total shareholder's equity	6,144	5,679
Total liabilities and shareholder's equity	$ 6,295	$ 5,834

The accompanying notes are an integral part of this financial statement schedule.

MHC INC.
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2015	**2014**	**2013**
Other income	$ 1	$ 2	$ 2
Income before income taxes	1	2	2
Income tax expense	—	1	1
Equity in undistributed earnings of subsidiaries	471	421	352
Net income	$ 472	$ 422	$ 353

The accompanying notes are an integral part of this financial statement schedule.

MHC INC.
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME
(Amounts in millions)

	Years Ended December 31,		
	2015	**2014**	**2013**
Net income	$ 472	$ 422	$ 353
Total other comprehensive (loss) income, net of tax	(7)	(12)	13
Comprehensive income	$ 465	$ 410	$ 366

The accompanying notes are an integral part of this financial statement schedule.

MHC INC.
PARENT COMPANY ONLY
CONDENSED STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31,		
	2015	**2014**	**2013**
Net cash flows from operating activities	$ 1	$ —	$ —
Net cash flows from investing activities:			
Dividend from subsidiary	16	—	125
Net change in amounts receivable from parent	(13)	(13)	(13)
Other	(1)	3	—
Net cash flows from investing activities	2	(10)	112
Net cash flows from financing activities:			
Net change in amounts payable to subsidiaries	(7)	10	(1)
Net change in note payable to Berkshire Hathaway Energy Company	3	1	(111)
Net cash flows from financing activities	(4)	11	(112)
Net change in cash and cash equivalents	(1)	1	—
Cash and cash equivalents at beginning of year	1	—	—
Cash and cash equivalents at end of year	$ —	$ 1	$ —

The accompanying notes are an integral part of this financial statement schedule.

MHC INC.
PARENT COMPANY ONLY
NOTES TO CONDENSED FINANCIAL STATEMENTS

Incorporated by reference are MHC Inc. and Subsidiaries Consolidated Statements of Changes in Equity for the three years ended December 31, 2015, in Part IV, Item 15(c).

Basis of Presentation - The condensed financial information of MHC Inc.'s ("MHC's") investments in subsidiaries is presented under the equity method of accounting. Under this method, the assets and liabilities of subsidiaries are not consolidated. The investments in and advances to subsidiaries are recorded on the Condensed Balance Sheets. The income from operations of the subsidiaries is reported on a net basis as equity in undistributed earnings of subsidiary companies on the Condensed Statements of Operations.

Receivable from Parent - MHC settles all obligations of MidAmerican Funding, LLC ("MidAmerican Funding") including primarily interest costs on MidAmerican Funding's long-term debt. Net amounts paid by MHC on behalf of MidAmerican Funding totaled $13 million, $13 million and $13 million for the years 2015, 2014 and 2013, respectively.

See the notes to the consolidated MHC financial statements in Part IV, Item 15(c) for other disclosures.

MIDAMERICAN ENERGY COMPANY
VALUATION AND QUALIFYING ACCOUNTS
FOR THE THREE YEARS ENDED DECEMBER 31, 2015
(Amounts in millions)

Column A Description	Column B Balance at Beginning of Year	Column C Additions Charged to Income	Column D Deductions	Column E Balance at End of Year
Reserves Deducted From Assets To Which They Apply:				
Reserve for uncollectible accounts receivable:				
Year ended 2015	$ 7	$ 7	$ (8)	$ 6
Year ended 2014	$ 10	$ 7	$ (10)	$ 7
Year ended 2013	$ 10	$ 7	$ (7)	$ 10
Reserves Not Deducted From Assets[(1)]:				
Year ended 2015	$ 11	$ 7	$ (5)	$ 13
Year ended 2014	$ 9	$ 12	$ (10)	$ 11
Year ended 2013	$ 9	$ 6	$ (6)	$ 9

(1) Reserves not deducted from assets include estimated liabilities for losses retained by MidAmerican Energy for workers compensation, public liability and property damage claims.

MIDAMERICAN FUNDING, LLC AND SUBSIDIARIES
MHC INC. AND SUBSIDIARIES
CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
FOR THE THREE YEARS ENDED DECEMBER 31, 2015
(Amounts in millions)

Column A Description	Column B Balance at Beginning of Year	Column C Additions Charged to Income	Column D Deductions	Column E Balance at End of Year
Reserves Deducted From Assets To Which They Apply:				
Reserve for uncollectible accounts receivable:				
Year ended 2015	$ 7	$ 7	$ (8)	$ 6
Year ended 2014	$ 10	$ 7	$ (10)	$ 7
Year ended 2013	$ 10	$ 7	$ (7)	$ 10
Reserves Not Deducted From Assets [(1)]:				
Year ended 2015	$ 11	$ 7	$ (5)	$ 13
Year ended 2014	$ 9	$ 12	$ (10)	$ 11
Year ended 2013	$ 9	$ 6	$ (6)	$ 9

(1) Reserves not deducted from assets include primarily estimated liabilities for losses retained by MidAmerican Funding and MHC for workers compensation, public liability and property damage claims.

Item 15(c) MHC Inc. Consolidated Financial Statements

The accompanying Consolidated Financial Statements of MHC Inc., the direct wholly owned subsidiary of MidAmerican Funding, are being provided pursuant to Rule 3-16 of the U. S. Securities and Exchange Commission's Regulation S-X. The purpose of these financial statements is to provide information about the assets and equity interests that collateralize MidAmerican Funding's long-term debt and that, upon the occurrence of any triggering event under the collateral agreement, would be available to satisfy the applicable debt obligations.

MHC Inc. and Subsidiaries

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
MHC Inc.
Des Moines, Iowa

We have audited the accompanying consolidated balance sheets of MHC Inc. and subsidiaries ("MHC") as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive income, changes in equity, and cash flows for each of the three years in the period ended December 31, 2015. Our audits also included MHC's financial statement schedules listed in the Index at Item 15(a)(2). These financial statements and financial statement schedules are the responsibility of MHC's management. Our responsibility is to express an opinion on the 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. MHC 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 MHC'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 MHC Inc. and subsidiaries as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly in all material respects the information set forth therein.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 26, 2016

MHC INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Amounts in millions, except share data)

	As of December 31,	
	2015	2014
ASSETS		
Current assets:		
Cash and cash equivalents	$ 103	$ 30
Receivables, net	343	435
Income taxes receivable	104	303
Inventories	238	185
Other current assets	58	86
Total current assets	846	1,039
Property, plant and equipment, net	11,737	10,535
Goodwill	1,270	1,270
Regulatory assets	1,044	908
Investments and restricted cash and investments	636	627
Receivable from affiliate	288	274
Other assets	138	141
Total assets	$ 15,959	$ 14,794

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

MHC INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (continued)
(Amounts in millions, except share data)

	As of December 31,	
	2015	**2014**
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities:		
Accounts payable	$ 426	$ 392
Accrued interest	46	40
Accrued property, income and other taxes	125	128
Note payable to affiliate	139	136
Short-term debt	—	50
Current portion of long-term debt	34	426
Other current liabilities	166	131
Total current liabilities	936	1,303
Long-term debt	4,237	3,608
Deferred income taxes	3,056	2,656
Regulatory liabilities	831	837
Asset retirement obligations	488	432
Other long-term liabilities	267	279
Total liabilities	9,815	9,115
Commitments and contingencies (Note 14)		
Shareholder's equity:		
Common stock - no par value, 1,000 shares authorized, 1,000 shares issued and outstanding	—	—
Additional paid-in capital	2,430	2,430
Retained earnings	3,744	3,272
Accumulated other comprehensive loss, net	(30)	(23)
Total shareholder's equity	6,144	5,679
Total liabilities and shareholder's equity	$ 15,959	$ 14,794

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

MHC INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Amounts in millions)

	Years Ended December 31,		
	2015	**2014**	**2013**
Operating revenue:			
Regulated electric	$ 1,837	$ 1,817	$ 1,762
Regulated gas	661	996	824
Nonregulated	922	949	827
Total operating revenue	3,420	3,762	3,413
Operating costs and expenses:			
Regulated:			
Cost of fuel, energy and capacity	433	532	517
Cost of gas sold	397	720	558
Operations and maintenance	687	699	659
Depreciation and amortization	407	351	403
Property and other taxes	124	123	119
Nonregulated:			
Cost of sales	864	881	764
Other	35	33	36
Total operating costs and expenses	2,947	3,339	3,056
Operating income	473	423	357
Other income and (expense):			
Interest expense	(184)	(175)	(152)
Allowance for borrowed funds	8	16	7
Allowance for equity funds	20	39	19
Other, net	20	18	22
Total non-operating income	(136)	(102)	(104)
Income before income tax benefit	337	321	253
Income tax benefit	(135)	(101)	(101)
Net income	472	422	354
Net income attributable to noncontrolling interests	—	—	1
Net income attributable to MHC	$ 472	$ 422	$ 353

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

MHC INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Amounts in millions)

	Years Ended December 31,		
	2015	2014	2013
Net income	$ 472	$ 422	$ 354
Other comprehensive (loss) income, net of tax:			
Unrealized gains on available-for-sale securities, net of tax of $-, $1 and $1	—	1	1
Unrealized (losses) gains on cash flow hedges, net of tax of $(4), $(10) and $9	(7)	(13)	12
Total other comprehensive (loss) income, net of tax	(7)	(12)	13
Comprehensive income	465	410	367
Comprehensive income attributable to noncontrolling interests	—	—	1
Comprehensive income attributable to MHC	$ 465	$ 410	$ 366

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

MHC INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(Amounts in millions)

	MHC Common Shareholder's Equity				
	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss), Net	Noncontrolling Interests	Total Equity
Balance, December 31, 2012	$ 2,430	$ 2,497	$ (24)	$ 27	$ 4,930
Net income	—	353	—	1	354
Other comprehensive income	—	—	13	—	13
Distributions to noncontrolling interests	—	—	—	(28)	(28)
Balance, December 31, 2013	2,430	2,850	(11)	—	5,269
Net income	—	422	—	—	422
Other comprehensive loss	—	—	(12)	—	(12)
Balance, December 31, 2014	2,430	3,272	(23)	—	5,679
Net income	—	472	—	—	472
Other comprehensive loss	—	—	(7)	—	(7)
Balance, December 31, 2015	$ 2,430	$ 3,744	$ (30)	$ —	$ 6,144

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

MHC INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Amounts in millions)

	Years Ended December 31,		
	2015	**2014**	**2013**
Cash flows from operating activities:			
Net income	$ 472	$ 422	$ 354
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	407	351	403
Deferred income taxes and amortization of investment tax credits	276	298	102
Changes in other assets and liabilities	49	47	57
Other, net	(70)	(49)	(29)
Changes in other operating assets and liabilities:			
Receivables, net	93	(2)	(60)
Inventories	(53)	44	13
Derivative collateral, net	33	(53)	5
Contributions to pension and other postretirement benefit plans, net	(8)	(2)	8
Accounts payable	(76)	30	23
Accrued property, income and other taxes, net	213	(253)	(164)
Other current assets and liabilities	12	—	22
Net cash flows from operating activities	1,348	833	734
Net cash flows from investing activities:			
Utility construction expenditures	(1,446)	(1,526)	(1,026)
Purchases of available-for-sale securities	(142)	(88)	(114)
Proceeds from sales of available-for-sale securities	135	80	102
Proceeds from sales of other investments	13	10	16
Other, net	(11)	(8)	10
Net cash flows from investing activities	(1,451)	(1,532)	(1,012)
Net cash flows from financing activities:			
Proceeds from long-term debt	649	840	940
Repayments of long-term debt	(426)	(356)	(670)
Repurchase of preferred securities of subsidiary	—	—	(28)
Net change in amounts receivable from/payable to affiliates	3	1	(124)
Net proceeds from short-term debt	(50)	50	—
Net cash flows from financing activities	176	535	118
Net change in cash and cash equivalents	73	(164)	(160)
Cash and cash equivalents at beginning of year	30	194	354
Cash and cash equivalents at end of year	$ 103	$ 30	$ 194

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

MHC INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Company Organization

MHC Inc. ("MHC") is an Iowa corporation with MidAmerican Funding, LLC ("MidAmerican Funding") as its sole shareholder. MidAmerican Funding is an Iowa limited liability company with Berkshire Hathaway Energy Company ("BHE") as its sole member. BHE is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway"). MHC constitutes substantially all of MidAmerican Funding's assets, liabilities and business activities except those related to MidAmerican Funding's long-term debt securities. MHC conducts no business other than the ownership of its subsidiaries and related corporate services. MHC's principal subsidiary is MidAmerican Energy Company ("MidAmerican Energy"), a public utility with electric and natural gas operations. Direct wholly owned nonregulated subsidiaries of MHC are Midwest Capital Group, Inc. and MEC Construction Services Co.

(2) Summary of Significant Accounting Policies

In addition to the following significant accounting policies, refer to Note 2 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K for significant accounting policies of MHC.

Basis of Consolidation and Presentation

The Consolidated Financial Statements include the accounts of MHC and its subsidiaries in which it held a controlling financial interest as of the date of the financial statement. Intercompany accounts and transactions have been eliminated, other than those between rate-regulated operations. MHC has evaluated subsequent events through February 26, 2016, which is the date the Consolidated Financial Statements were issued.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of identifiable net assets acquired when MidAmerican Funding purchased MHC. MHC evaluates goodwill for impairment at least annually and completed its annual review as of October 31. When evaluating goodwill for impairment, MHC estimates the fair value of the reporting unit. If the carrying amount of a reporting unit, including goodwill, exceeds the estimated fair value, then the identifiable assets, including identifiable intangible assets, and liabilities of the reporting unit are estimated at fair value as of the current testing date. The excess of the estimated fair value of the reporting unit over the current estimated fair value of net assets establishes the implied value of goodwill. The excess of the recorded goodwill over the implied goodwill value is charged to earnings as an impairment loss. Significant judgment is required in estimating the fair value of the reporting unit and performing goodwill impairment tests. MHC uses a variety of methods to estimate a reporting unit's fair value, principally discounted projected future net cash flows. Key assumptions used include, but are not limited to, the use of estimated future cash flows; multiples of earnings and regulatory asset value; and an appropriate discount rate. In estimating future cash flows, MHC incorporates current market information, as well as historical factors. As such, the determination of fair value incorporates significant unobservable inputs. During 2015, 2014 and 2013, MHC did not record any goodwill impairments.

(3) Property, Plant and Equipment, Net

Refer to Note 3 of MidAmerican Energy's Notes to Financial Statements. In addition to MidAmerican Energy's property, plant and equipment, net, MHC had gross nonregulated property of $22 million as of December 31, 2015 and 2014 and related accumulated depreciation and amortization of $8 million as of December 31, 2015 and 2014, which consisted primarily of a corporate aircraft owned by MHC.

(4) Jointly Owned Utility Facilities

Refer to Note 4 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K.

(5) Regulatory Matters

Refer to Note 5 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K.

(6) Investments and Restricted Cash and Investments

Refer to Note 6 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K. In addition to MidAmerican Energy's investments and restricted cash and investments, MHC had corporate-owned life insurance policies in a Rabbi trust owned by MHC with a total cash surrender value of $2 million as of December 31, 2015 and 2014.

(7) Short-Term Debt and Credit Facilities

Refer to Note 7 of MidAmerican Energy's Notes to Financial Statements. In addition to MidAmerican Energy's credit facilities, MHC has a $4 million unsecured credit facility, which expires in June 2016 and has a variable interest rate based on LIBOR plus a spread. As of December 31, 2015 and 2014, there were no borrowings outstanding under this credit facility. As of December 31, 2015, MHC was in compliance with the covenants of its revolving credit facility.

(8) Long-Term Debt

Refer to Note 8 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K.

(9) Income Taxes

MHC's income tax benefit consists of the following for the years ended December 31 (in millions):

	2015	2014	2013
Current:			
Federal	$ (401)	$ (397)	$ (193)
State	(10)	(2)	(10)
	(411)	(399)	(203)
Deferred:			
Federal	282	297	100
State	(5)	2	3
	277	299	103
Investment tax credits	(1)	(1)	(1)
Total	$ (135)	$ (101)	$ (101)

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

	2015	2014	2013
Federal statutory income tax rate	35 %	35 %	35 %
Income tax credits	(62)	(57)	(68)
State income tax, net of federal income tax benefit	(3)	(1)	(2)
Effects of ratemaking	(11)	(8)	(3)
Other, net	1	—	(2)
Effective income tax rate	(40)%	(31)%	(40)%

Income tax credits relate primarily to production tax credits earned by MidAmerican Energy's wind-powered generating facilities. Federal renewable electricity production tax credits are earned as energy from qualifying wind-powered generating facilities is produced and sold and are based on a per-kilowatt hour rate pursuant to the applicable federal income tax law. Wind-powered generating facilities are eligible for the credits for 10 years from the date the qualifying generating facilities are placed in-service.

MHC's net deferred income tax liability consists of the following as of December 31 (in millions):

	2015	2014
Deferred income tax assets:		
Regulatory liabilities	$ 327	$ 332
Employee benefits	66	68
Derivative contracts	29	30
Asset retirement obligations	214	185
Other	68	70
Total deferred income tax assets	704	685
Deferred income tax liabilities:		
Depreciable property	(3,326)	(2,950)
Regulatory assets	(418)	(366)
Other	(16)	(25)
Total deferred income tax liabilities	(3,760)	(3,341)
Net deferred income tax liability	$ (3,056)	$ (2,656)

As of December 31, 2015, MHC has available $23 million of state carryforwards, principally related to $488 million of net operating losses, that expire at various intervals between 2016 and 2034.

The United States Internal Revenue Service has closed its examination of BHE's income tax returns through December 2009, including components related to MHC. In addition, state jurisdictions have closed their examinations of MidAmerican Energy's income tax returns through at least February 9, 2006, including Iowa and Illinois, which are closed through December 31, 2012, and December 31, 2008, respectively.

A reconciliation of the beginning and ending balances of MHC's net unrecognized tax benefits is as follows for the years ended December 31 (in millions):

	2015	2014
Beginning balance	$ 26	$ 29
Additions based on tax positions related to the current year	4	6
Additions for tax positions of prior years	46	38
Reductions based on tax positions related to the current year	(6)	(4)
Reductions for tax positions of prior years	(46)	(40)
Statute of limitations	(5)	(3)
Settlements	(6)	—
Interest and penalties	(3)	—
Ending balance	$ 10	$ 26

As of December 31, 2015, MHC had unrecognized tax benefits totaling $27 million that, if recognized, would have an impact on the effective tax rate. The remaining unrecognized tax benefits relate 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 MHC's effective income tax rate.

(10) Employee Benefit Plans

Refer to Note 10 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K for additional information regarding MHC's pension, supplemental retirement and postretirement benefit plans.

Pension and postretirement costs allocated by MHC to its parent and other affiliates in each of the years ended December 31, were as follows (in millions):

	2015	2014	2013
Pension costs	$ 4	$ 4	$ 6
Other postretirement costs	(2)	(2)	(2)

(11) Asset Retirement Obligations

Refer to Note 11 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K.

(12) Risk Management and Hedging Activities

Refer to Note 12 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K.

(13) Fair Value Measurements

Refer to Note 13 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K.

(14) Commitments and Contingencies

Refer to Note 14 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K.

Legal Matters

MHC is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. MHC does not believe that such normal and routine litigation will have a material impact on its consolidated financial results.

(15) Components of Accumulated Other Comprehensive Loss, Net

Refer to Note 15 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K.

(16) Noncontrolling Interests

Refer to Note 16 of MidAmerican Energy's Notes to Financial Statements in Item 8 of this Form 10-K for a discussion of MidAmerican Energy's preferred securities, which were MHC's noncontrolling interest at the time of their redemption.

(17) Other Income and (Expense) - Other, Net

Other, net, as shown on the Consolidated Statements of Operations, includes the following other income (expense) items for the years ended December 31 (in millions):

	2015	2014	2013
Corporate-owned life insurance income	$ 4	$ 8	$ 15
Gains on sales of assets and other investments	13	—	1
Leverage leases	1	5	2
Other, net	2	5	4
Total	$ 20	$ 18	$ 22

MidAmerican Funding recognized a $13 million pre-tax gain on the sale of an investment in a generating facility lease in 2015.

(18) Supplemental Cash Flow Information

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

	2015	2014	2013
Supplemental cash flow information:			
Interest paid, net of amounts capitalized	$ 154	$ 144	$ 109
Income taxes received, net	$ 621	$ 143	$ 32
Supplemental disclosure of non-cash investing and financing transactions:			
Accounts payable related to utility plant additions	$ 249	$ 128	$ 117

(19) Related Party Transactions

The companies identified as affiliates of MHC are Berkshire Hathaway and its subsidiaries, including BHE and its subsidiaries. The basis for the following transactions is provided for in service agreements between MHC and the affiliates.

MHC is reimbursed for charges incurred on behalf of its affiliates. The majority of these reimbursed expenses are for allocated general costs, such as insurance and building rent, and for employee wages, benefits and costs for corporate functions, such as information technology, human resources, treasury, legal and accounting. The amount of such reimbursements was $35 million, $37 million and $28 million for 2015, 2014 and 2013, respectively.

MHC reimbursed BHE in the amount of $7 million, $8 million and $10 million in 2015, 2014 and 2013, respectively, for its share of corporate expenses.

MidAmerican Energy purchases natural gas transportation and storage capacity services from Northern Natural Gas Company, a wholly owned subsidiary of BHE, and coal transportation services from BNSF Railway Company, a wholly-owned subsidiary of Berkshire Hathaway, in the normal course of business at either tariffed or market prices. These purchases totaled $165 million, $144 million and $155 million in 2015, 2014 and 2013, respectively.

MHC has a $300 million revolving credit arrangement carrying interest at the 30-day LIBOR rate plus a spread to borrow from BHE. Outstanding balances are unsecured and due on demand. The outstanding balance was $139 million at an interest rate of 0.494% as of December 31, 2015, and $136 million at an interest rate of 0.408% as of December 31, 2014, and is reflected as note payable to affiliate on the Consolidated Balance Sheet.

BHE has a $100 million revolving credit arrangement carrying interest at the 30-day LIBOR rate plus a spread to borrow from MHC. Outstanding balances are unsecured and due on demand. There were no borrowings outstanding throughout 2015 and 2014.

MHC settles all obligations of MidAmerican Funding including primarily interest costs on MidAmerican Funding's long-term debt. Net amounts paid by MHC on behalf of MidAmerican Funding totaled $13 million for 2015, 2014 and 2013.

MHC had accounts receivable from affiliates of $292 million and $281 million as of December 31, 2015 and 2014, respectively, that are reflected in receivables, net and receivable from affiliate on the Consolidated Balance Sheets. MHC also had accounts payable to affiliates of $12 million as of December 31, 2015 and 2014, that are included in accounts payable on the Consolidated Balance Sheets.

MHC is party to a tax-sharing agreement and is part of the Berkshire Hathaway United States federal income tax return. As of December 31, 2015 and 2014, MHC had current federal and state income taxes receivable from BHE of $102 million and $296 million, respectively. MHC received net cash receipts for federal and state income taxes from BHE totaling $621 million, $144 million and $32 million for the years ended December 31, 2015, 2014 and 2013, respectively.

MHC recognizes the full amount of the funded status for its pension and postretirement plans, and amounts attributable to MHC's affiliates that have not previously been recognized through income are recognized as an intercompany balance with such affiliates. MHC adjusts these balances when changes to the funded status of the respective plans are recognized and does not intend to settle the balances currently. Amounts receivable from affiliates attributable to the funded status of employee benefit plans totaled $10 million and $13 million as of December 31, 2015 and 2014, respectively, and similar amounts payable to affiliates totaled $29 million and $30 million, as of December 31, 2015 and 2014, respectively. See Note 10 for further information pertaining to pension and postretirement accounting.

(20) Segment Information

MHC has identified three reportable operating segments: regulated electric, regulated gas and nonregulated energy. The regulated electric segment derives most of its revenue from regulated retail sales of electricity to residential, commercial, and industrial customers and from wholesale sales. The regulated gas segment derives most of its revenue from regulated retail sales of natural gas to residential, commercial, and industrial customers and also obtains revenue by transporting gas owned by others through its distribution system. Pricing for regulated electric and regulated gas sales are established separately by regulatory agencies; therefore, management also reviews each segment separately to make decisions regarding allocation of resources and in evaluating performance. The nonregulated energy segment derives most of its revenue from nonregulated retail electric and gas activities. Common operating costs, interest income, interest expense and income tax expense are allocated to each segment based on certain factors, which primarily relate to the nature of the cost. "Other" in the tables below consists principally of the nonregulated subsidiaries of MHC not engaged in the energy business. Refer to Note 9 for a discussion of items affecting income tax (benefit) expense for the regulated electric and gas operating segments.

The following tables provide information on a reportable segment basis (in millions):

	Years Ended December 31,		
	2015	2014	2013
Operating revenue:			
Regulated electric	$ 1,837	$ 1,817	$ 1,762
Regulated gas	661	996	824
Nonregulated energy	910	927	817
Other	12	22	10
Total operating revenue	$ 3,420	$ 3,762	$ 3,413
Depreciation and amortization:			
Regulated electric	$ 366	$ 312	$ 366
Regulated gas	41	39	37
Total depreciation and amortization	$ 407	$ 351	$ 403
Operating income:			
Regulated electric	$ 385	$ 319	$ 255
Regulated gas	64	75	74
Nonregulated energy	22	28	27
Other	2	1	1
Total operating income	$ 473	$ 423	$ 357
Interest expense:			
Regulated electric	$ 166	$ 157	$ 136
Regulated gas	17	17	15
Other	1	1	1
Total interest expense	$ 184	$ 175	$ 152
Income tax (benefit) expense:			
Regulated electric	$ (163)	$ (138)	$ (136)
Regulated gas	16	22	23
Nonregulated energy	6	12	10
Other	6	3	2
Total income tax (benefit) expense	$ (135)	$ (101)	$ (101)
Net income attributable to MHC:			
Regulated electric	$ 413	$ 361	$ 292
Regulated gas	33	40	41
Nonregulated energy	16	16	16
Other	10	5	4
Total net income attributable to MHC	$ 472	$ 422	$ 353
Utility construction expenditures:			
Regulated electric	$ 1,365	$ 1,429	$ 945
Regulated gas	81	97	81
Total utility construction expenditures	$ 1,446	$ 1,526	$ 1,026

	As of December 31,		
	2015	2014	2013
Total assets:			
Regulated electric	$ 14,161	$ 13,041	$ 11,712
Regulated gas	1,330	1,296	1,275
Nonregulated energy	164	167	131
Other	304	290	287
Total assets	$ 15,959	$ 14,794	$ 13,405

Goodwill by reportable segment as of December 31, 2015 and 2014 was as follows (in millions):

Regulated electric	$ 1,191
Regulated gas	79
Total	$ 1,270

(21) Transfer of Nonregulated Energy Operations

Refer to Note 21 of MidAmerican Energy's Notes to Financial Statements.

SIGNATURES

BERKSHIRE HATHAWAY ENERGY COMPANY

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 26th day of February 2016.

BERKSHIRE HATHAWAY ENERGY COMPANY

/s/ Gregory E. Abel*
Gregory E. Abel
Chairman, President and Chief Executive Officer
(principal executive officer)

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

Signature	Title	Date
/s/ Gregory E. Abel* Gregory E. Abel	Chairman, President and Chief Executive Officer (principal executive officer)	February 26, 2016
/s/ Patrick J. Goodman* Patrick J. Goodman	Executive Vice President and Chief Financial Officer (principal financial and accounting officer)	February 26, 2016
/s/ Walter Scott, Jr.* Walter Scott, Jr.	Director	February 26, 2016
/s/ Marc D. Hamburg* Marc D. Hamburg	Director	February 26, 2016
/s/ Warren E. Buffett* Warren E. Buffett	Director	February 26, 2016
*By: /s/ Douglas L. Anderson Douglas L. Anderson	Attorney-in-Fact	February 26, 2016

SIGNATURES

PACIFICORP

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 26th day of February 2016.

PACIFICORP

/s/ Nikki L. Kobliha
Nikki L. Kobliha
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 26, 2016
/s/ Nikki L. Kobliha Nikki L. Kobliha	Vice President and Chief Financial Officer (principal financial and accounting officer)	February 26, 2016
/s/ Douglas L. Anderson Douglas L. Anderson	Director	February 26, 2016
/s/ Stefan A. Bird Stefan A. Bird	Director	February 26, 2016
/s/ Cindy A. Crane Cindy A. Crane	Director	February 26, 2016
/s/ Patrick J. Goodman Patrick J. Goodman	Director	February 26, 2016
/s/ Natalie L. Hocken Natalie L. Hocken	Director	February 26, 2016
/s/ Andrea L. Kelly Andrea L. Kelly	Director	February 26, 2016
/s/ R. Patrick Reiten R. Patrick Reiten	Director	February 26, 2016

SIGNATURES

MIDAMERICAN ENERGY COMPANY

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 26th day of February 2016.

MIDAMERICAN ENERGY COMPANY

/s/ William J. Fehrman
William J. Fehrman
President and Chief Executive Officer
(principal executive officer)

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

Signatures	Title	Date
/s/William J. Fehrman William J. Fehrman	President, Chief Executive Officer and Director (principal executive officer)	February 26, 2016
/s/Thomas B. Specketer Thomas B. Specketer	Vice President, Chief Financial Officer and Director (principal financial and accounting officer)	February 26, 2016
/s/Robert B. Berntsen Robert B. Berntsen	Senior Vice President, General Counsel and Director	February 26, 2016

MIDAMERICAN FUNDING, LLC

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 26th day of February 2016.

MIDAMERICAN FUNDING, LLC

/s/ William J. Fehrman
William J Fehrman
President
(principal executive officer)

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

Signatures	Title	Date
/s/William J. Fehrman William J. Fehrman	President and Manager (principal executive officer)	February 26, 2016
/s/Thomas B. Specketer Thomas B. Specketer	Vice President and Controller (principal financial and accounting officer)	February 26, 2016
/s/Patrick J. Goodman Patrick J. Goodman	Manager	February 26, 2016
/s/Sandra Hatfield Clubb Sandra Hatfield Clubb	Manager	February 26, 2016
/s/Douglas L. Anderson Douglas L. Anderson	Manager	February 26, 2016

SIGNATURES

NEVADA POWER COMPANY

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 26th day of February 2016.

NEVADA POWER COMPANY

/s/ Paul J. Caudill

Paul J. Caudill
President and Chief Executive Officer
(principal executive officer)

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

Signature	Title	Date
/s/ Paul J. Caudill Paul J. Caudill	President and Chief Executive Officer (principal executive officer)	February 26, 2016
/s/ E. Kevin Bethel E. Kevin Bethel	Senior Vice President, Chief Financial Officer and Director (principal financial and accounting officer)	February 26, 2016
/s/ Douglas A. Cannon Douglas A. Cannon	Senior Vice President, Corporate Secretary, General Counsel and Director	February 26, 2016
/s/ Patrick S. Egan Patrick S. Egan	Senior Vice President, Customer Services and Director	February 26, 2016
/s/ Kevin C. Geraghty Kevin C. Geraghty	Director	February 26, 2016
/s/ Francis P. Gonzales Francis P. Gonzales	Director	February 26, 2016
/s/ John C. Owens John C. Owens	Director	February 26, 2016
/s/ Tony F. Sanchez, III Tony F. Sanchez, III	Senior Vice President, Government and Community Strategy and Director	February 26, 2016

SIGNATURES

SIERRA PACIFIC POWER COMPANY

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 26th day of February 2016.

SIERRA PACIFIC POWER COMPANY

/s/ Paul J. Caudill

Paul J. Caudill
President and Chief Executive Officer
(principal executive officer)

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

Signature	Title	Date
/s/ Paul J. Caudill Paul J. Caudill	President and Chief Executive Officer (principal executive officer)	February 26, 2016
/s/ E. Kevin Bethel E. Kevin Bethel	Senior Vice President, Chief Financial Officer and Director (principal financial and accounting officer)	February 26, 2016
/s/ Douglas A. Cannon Douglas A. Cannon	Senior Vice President, Corporate Secretary, General Counsel and Director	February 26, 2016
/s/ Patrick S. Egan Patrick S. Egan	Senior Vice President, Customer Services and Director	February 26, 2016
/s/ Kevin C. Geraghty Kevin C. Geraghty	Director	February 26, 2016
/s/ Francis P. Gonzales Francis P. Gonzales	Director	February 26, 2016
/s/ John C. Owens John C. Owens	Director	February 26, 2016
/s/ Tony F. Sanchez, III Tony F. Sanchez, III	Senior Vice President, Government and Community Strategy and Director	February 26, 2016

SUPPLEMENTAL INFORMATION TO BE FURNISHED WITH REPORTS FILED PURSUANT TO SECTION 15(D) OF THE ACT BY REGISTRANTS WHICH HAVE NOT REGISTERED SECURITIES PURSUANT TO SECTION 12 OF THE ACT

No annual report to security holders covering each respective Registrant's last fiscal year or proxy material has been sent to security holders.

EXHIBIT INDEX

BERKSHIRE HATHAWAY ENERGY

3.1	Second Amended and Restated Articles of Incorporation of MidAmerican Energy Holdings Company effective March 2, 2006 (incorporated by reference to Exhibit 3.1 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2005).
3.2	Articles of Amendment to the Second Amended and Restated Articles of Incorporation of MidAmerican Energy Holdings Company effective April 30, 2014 (incorporated by reference to Exhibit 3.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2014).
3.3	Amended and Restated Bylaws of Berkshire Hathaway Energy Company (incorporated by reference to Exhibit 3.2 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2005).
4.1	Shareholders Agreement, dated as of March 14, 2000 (incorporated by reference to Exhibit 4.19 to the Berkshire Hathaway Energy Company Registration Statement No. 333-101699 dated December 6, 2002).
4.2	Amendment No. 1 to Shareholders Agreement, dated December 7, 2005 (incorporated by reference to Exhibit 4.17 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2005).
4.3	Indenture, dated as of December 19, 2013, by and between MidAmerican Energy Holdings Company and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the Junior Subordinated Debentures due 2043 (including form of junior subordinated debenture) (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated December 19, 2013).
4.4	Indenture, dated as of November 12, 2014, by and between Berkshire Hathaway Energy Company and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the Junior Subordinated Debentures due 2044 (including form of junior subordinated debenture) (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated December 1, 2014).
4.5	Indenture, dated as of October 4, 2002, by and between MidAmerican Energy Holdings Company and The Bank of New York, Trustee (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Registration Statement No. 333-101699 dated December 6, 2002).
4.6	Fourth Supplemental Indenture, dated as of March 24, 2006, by and between MidAmerican Energy Holdings Company and The Bank of New York Trust Company, N.A., Trustee, relating to the 6.125% Senior Bonds due 2036 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated March 28, 2006).
4.7	Fifth Supplemental Indenture, dated as of May 11, 2007, by and between MidAmerican Energy Holdings Company and The Bank of New York Trust Company, N.A., Trustee, relating to the 5.95% Senior Bonds due 2037 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated May 11, 2007).
4.8	Sixth Supplemental Indenture, dated as of August 28, 2007, by and between MidAmerican Energy Holdings Company and The Bank of New York Trust Company, N.A., Trustee, relating to the 6.50% Senior Bonds due 2037 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated August 28, 2007).
4.9	Seventh Supplemental Indenture, dated as of March 28, 2008, by and between MidAmerican Energy Holdings Company and The Bank of New York Trust Company, N.A., as Trustee, relating to the 5.75% Senior Notes due 2018 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated March 28, 2008).

Exhibit No.	Description
4.10	Ninth Supplemental Indenture, dated as of November 8, 2013, by and between MidAmerican Energy Holdings Company and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the 1.100% Senior Notes due 2017, the 2.000% Senior Notes due 2018, the 3.750% Senior Notes due 2023 and the 5.150% Senior Notes due 2043 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated November 8, 2013).
4.11	Tenth Supplemental Indenture, dated as December 4, 2014, by and between Berkshire Hathaway Energy Company and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the 2.40% Senior Notes due 2020, the 3.50% Senior Notes due 2025 and the 4.50% Senior Notes due 2045 (incorporated by reference to Exhibit 4.8 to the Berkshire Hathaway Energy Company Registration Statement No. 333-200928 dated December 12, 2014).
4.12	Indenture, dated as of October 15, 1997, by and between MidAmerican Energy Holdings Company and IBJ Schroder Bank & Trust Company, Trustee (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated October 23, 1997).
4.13	Form of Second Supplemental Indenture, dated as of September 22, 1998 by and between MidAmerican Energy Holdings Company and IBJ Schroder Bank & Trust Company, Trustee, relating to the 8.48% Senior Notes in the principal amount of $475,000,000 due 2028 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated September 17, 1998).
4.14	Indenture, dated May 1, 2000, between NV Energy, Inc. (under its former name, Sierra Pacific Resources) and The Bank of New York, relating to the issuance of debt securities (incorporated by reference to Exhibit 4.1 to the NV Energy, Inc. Current Report on Form 8-K dated May 22, 2000).
4.15	Form of Officers' Certificate establishing the terms of NV Energy, Inc.'s 6.25% Senior Notes due 2020 (incorporated by reference to Exhibit 4.1 to the NV Energy, Inc. Current Report on Form 8-K dated November 19, 2010).
4.16	Trust Deed, dated December 15, 1997 among CE Electric UK Funding Company, AMBAC Insurance UK Limited and The Law Debenture Trust Corporation, p.l.c., Trustee (incorporated by reference to Exhibit 99.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated March 30, 2004).
4.17	Insurance and Indemnity Agreement, dated December 15, 1997 by and between CE Electric UK Funding Company and AMBAC Insurance UK Limited (incorporated by reference to Exhibit 99.2 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated March 30, 2004).
4.18	Supplemental Agreement to Insurance and Indemnity Agreement, dated September 19, 2001, by and between CE Electric UK Funding Company and AMBAC Insurance UK Limited (incorporated by reference to Exhibit 99.3 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated March 30, 2004).
4.19	Trust Indenture, dated as of September 10, 1999, by and between Cordova Funding Corporation and Chase Manhattan Bank and Trust Company, National Association, Trustee, relating to the $225,000,000 in principal amount of the 8.75% Senior Secured Bonds due 2019 (incorporated by reference to Exhibit 10.71 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
4.20	Trust Deed, dated as of February 4, 1998 among Yorkshire Power Finance Limited, Yorkshire Power Group Limited and Bankers Trustee Company Limited, Trustee, relating to the £200,000,000 in principal amount of the 7.25% Guaranteed Bonds due 2028 (incorporated by reference to Exhibit 10.74 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
4.21	First Supplemental Trust Deed, dated as of October 1, 2001, among Yorkshire Power Finance Limited, Yorkshire Power Group Limited and Bankers Trustee Company Limited, Trustee, relating to the £200,000,000 in principal amount of the 7.25% Guaranteed Bonds due 2028 (incorporated by reference to Exhibit 10.75 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).

Exhibit No.	Description
4.22	Third Supplemental Trust Deed, dated as of October 1, 2001, among Yorkshire Electricity Distribution plc, Yorkshire Electricity Group plc and Bankers Trustee Company Limited, Trustee, relating to the £200,000,000 in principal amount of the 9.25% Bonds due 2020 (incorporated by reference to Exhibit 10.76 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
4.23	First Supplemental Trust Deed, dated as of September 27, 2001, among Northern Electric Finance plc, Northern Electric plc, Northern Electric Distribution Limited and The Law Debenture Trust Corporation p.l.c., Trustee, relating to the £100,000,000 in principal amount of the 8.875% Guaranteed Bonds due 2020 (incorporated by reference to Exhibit 10.81 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
4.24	Trust Deed, dated as of January 17, 1995, by and between Yorkshire Electricity Group plc and Bankers Trustee Company Limited, Trustee, relating to the £200,000,000 in principal amount of the 9 1/4% Bonds due 2020 (incorporated by reference to Exhibit 10.83 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
4.25	Master Trust Deed, dated as of October 16, 1995, by and between Northern Electric Finance plc, Northern Electric plc and The Law Debenture Trust Corporation p.l.c., Trustee, relating to the £100,000,000 in principal amount of the 8.875% Guaranteed Bonds due 2020 (incorporated by reference to Exhibit 10.70 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2004).
4.26	Trust Deed dated May 5, 2005 among Northern Electric Finance plc, Northern Electric Distribution Limited, Ambac Assurance UK Limited and HSBC Trustee (C.I.) Limited (incorporated by reference to Exhibit 99.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
4.27	Reimbursement and Indemnity Agreement, dated May 5, 2005 among Northern Electric Finance plc, Northern Electric Distribution Limited and Ambac Assurance UK Limited (incorporated by reference to Exhibit 99.2 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
4.28	Trust Deed, dated May 5, 2005 among Yorkshire Electricity Distribution plc, Ambac Assurance UK Limited and HSBC Trustee (C.I.) Limited (incorporated by reference to Exhibit 99.3 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
4.29	Reimbursement and Indemnity Agreement, dated May 5, 2005 between Yorkshire Electricity Distribution plc and Ambac Assurance UK Limited (incorporated by reference to Exhibit 99.4 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
4.30	Supplemental Trust Deed, dated May 5, 2005 among CE Electric UK Funding Company, Ambac Assurance UK Limited and The Law Debenture Trust Corporation plc (incorporated by reference to Exhibit 99.5 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
4.31	Second Supplemental Agreement to Insurance and Indemnity Agreement, dated May 5, 2005 by and between CE Electric UK Funding Company and Ambac Assurance UK Limited (incorporated by reference to Exhibit 99.6 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2005).
4.32	£119,000,000 Finance Contract, dated July 2, 2010, by and between Northern Electric Distribution Limited and the European Investment Bank (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2010).
4.33	Guarantee and Indemnity Agreement, dated July 2, 2010, by and between CE Electric UK Funding Company and the European Investment Bank (incorporated by reference to Exhibit 4.2 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2010).
4.34	£151,000,000 Finance Contract, dated July 2, 2010, by and between Yorkshire Electricity Distribution plc and the European Investment Bank (incorporated by reference to Exhibit 4.3 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2010).

Exhibit No.	Description
4.35	Guarantee and Indemnity Agreement, dated July 2, 2010, by and between CE Electric UK Funding Company and the European Investment Bank (incorporated by reference to Exhibit 4.4 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2010).
4.36	Trust Deed, dated as of July 5, 2012, among Northern Powergrid (Yorkshire) plc and HSBC Corporate Trustee Company (UK) Limited, relating to the £150,000,000 in principal amount of the 4.375% Bonds due 2032 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2012).
4.37	Trust Deed, dated as of April 1, 2015, among Northern Powergrid (Yorkshire) plc and HSBC Corporate Trustee Company (UK) Limited, relating to the £150,000,000 in principal amount of the 2.50% Bonds due 2025 (incorporated by reference to Exhibit 4.3 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2015).
4.38	Fiscal Agency Agreement, dated as of July 15, 2008, by and between Northern Natural Gas Company and The Bank New York Mellon Trust Company, National Association, Fiscal Agent, relating to the $200,000,000 in principal amount of the 5.75% Senior Notes due 2018 (incorporated by reference to Exhibit 4.32 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2008).
4.39	Fiscal Agency Agreement, dated as of April 20, 2011, by and between Northern Natural Gas Company and The Bank of New York Mellon Trust Company, N.A., Fiscal Agent, relating to the $200,000,000 in principal amount of the 4.25% Senior Notes due 2021 (incorporated by reference to Exhibit 4.27 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2011).
4.40	Fiscal Agency Agreement, dated February 12, 2007, by and between Northern Natural Gas Company and The Bank of New York Trust Company, N.A., Fiscal Agent, relating to the $150,000,000 in principal amount of the 5.80% Senior Bonds due 2037 (incorporated by reference to Exhibit 99.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated February 12, 2007).
4.41	Fiscal Agency Agreement, dated August 27, 2012, by and between Northern Natural Gas Company and The Bank of New York Mellon Trust Company, N.A., Fiscal Agent, relating to the $250,000,000 in principal amount of the 4.10% Senior Bonds due 2042 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2012).
4.42	Trust Indenture, dated as of August 13, 2001, among Kern River Funding Corporation, Kern River Gas Transmission Company and JP Morgan Chase Bank, Trustee (incorporated by reference to Exhibit 10.48 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2003).
4.43	Third Supplemental Indenture, dated as of May 1, 2003, among Kern River Funding Corporation, Kern River Gas Transmission Company and JPMorgan Chase Bank, Trustee, relating to the $836,000,000 in principal amount of the 4.893% Senior Notes due 2018 (incorporated by reference to Exhibit 10.49 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2003).
4.44	Master Trust Indenture, dated November 21, 2005, by and between AltaLink Investments, L.P., AltaLink Investment Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.94 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.45	Series 09-1 Supplemental Indenture, dated December 16, 2009, by and between AltaLink Investments, L.P., AltaLink Investment Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.95 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.46	Third Supplemental Indenture, dated December 15, 2010, by and between AltaLink Investments, L.P., AltaLink Investment Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.96 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).

Exhibit No.	Description
4.47	Series 12-1 Supplemental Indenture, dated June 5, 2012, by and between AltaLink Investments, L.P., AltaLink Investment Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.97 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.48	Series 13-1 Supplemental Indenture, dated April 9, 2013, by and between AltaLink Investments, L.P., AltaLink Investment Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.98 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.49	Series 15-1 Supplemental Indenture, dated March 6, 2015, by and between AltaLink Investments, L.P., AltaLink Investment Management Ltd. and BNY Trust Company of Canada, relating to C$200,000,000 in principal amount of the 2.244% Series 15-1 Senior Bonds due 2022 (incorporated by reference to Exhibit 4.2 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2015).
4.50	Amended and Restated Master Trust Indenture, dated April 28, 2003, by and between AltaLink, L.P., AltaLink Management Ltd. and BMO Trust Company (incorporated by reference to Exhibit 4.99 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.51	Seventh Supplemental Indenture, dated April 28, 2003, by and between AltaLink, L.P., AltaLink Management Ltd. and BMO Trust Company (incorporated by reference to Exhibit 4.100 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.52	Ninth Supplemental Indenture, dated May 9, 2006, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.101 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.53	Tenth Supplemental Indenture, dated May 21, 2008, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.102 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.54	Twelfth Supplemental Indenture, dated August 18, 2010, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.103 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.55	Sixteenth Supplemental Indenture, dated November 15, 2012, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.104 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.56	Seventeenth Supplemental Indenture, dated May 22, 2013, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.105 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.57	Eighteenth Supplemental Indenture, dated October 24, 2014, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.106 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.58	Nineteenth Supplemental Indenture, dated October 24, 2014, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada (incorporated by reference to Exhibit 4.107 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.59	Twentieth Supplemental Indenture, dated June 30, 2015, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada, relating to C$350,000,000 in principal amount of the 4.09% Series 2015-1 Medium-Term Notes due 2045 (incorporated by reference to Exhibit 4.5 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2015).

Exhibit No.	Description
4.60	Indenture, dated as of February 24, 2012, by and between Topaz Solar Farms LLC and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the $850,000,000 in principal amount of the 5.75% Series A Senior Secured Notes due 2039 (incorporated by reference to Exhibit 4.56 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2011).
4.61	First Supplemental Indenture, dated as of April 15, 2013, between Topaz Solar Farms LLC, as Issuer, and The Bank of New York Mellon Trust Company, N.A., as Trustee, relating to the $250,000,000 in principal amount of the 4.875% Series B Senior Secured Notes due 2039 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2013).
4.62	Indenture, dated as of June 27, 2013, between Solar Star Funding, LLC, as Issuer, and Wells Fargo Bank, National Association, as Trustee, relating to the $1,000,000,000 in principal amount of the 5.375% Series A Senior Secured Notes due 2035 (incorporated by reference to Exhibit 4.2 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2013).
4.63	First Supplemental Indenture, dated as of March 12, 2015, between Solar Star Funding, LLC, as Issuer, and Wells Fargo Bank, National Association, as Trustee, relating to the $325,000,000 in principal amount of the 3.95% Series B Senior Secured Notes due 2035 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2015).
4.64	Indenture, dated as of March 2, 1999, by and between CE Generation, LLC and Chase Manhattan Bank and Trust Company, National Association (incorporated by reference to Exhibit 4.1 to the CE Generation, LLC Registration Statement No. 333-89521 dated October 22, 1999).
4.65	First Supplemental Indenture, dated as of February 4, 2000, by and between CE Generation, LLC and Chase Manhattan Bank and Trust Company, National Association (incorporated by reference to Exhibit 4.2 to the CE Generation, LLC Registration Statement No. 333-89521 dated October 22, 1999).
4.66	Second Supplemental Indenture, dated as of March 6, 2000, by and between CE Generation, LLC and Chase Manhattan Bank and Trust Company, National Association (incorporated by reference to Exhibit 4.89 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
4.67	Indenture, dated July 21, 1995, by and between Salton Sea Funding Corporation and Chase Manhattan Bank and Trust Company, National Association (incorporated by reference to Exhibit 4.1(a) to the Salton Sea Funding Corporation Registration Statement No. 333-95538 dated January 10, 1996).
4.68	Fourth Supplemental Indenture, dated October 13, 1998, by and between Salton Sea Funding Corporation and Chase Manhattan Bank and Trust Company, National Association (incorporated by reference to Exhibit 4.1(e) to the Salton Sea Funding Corporation Annual Report on Form 10-K/A for the year ended December 31, 1998).
4.69	Fifth Supplemental Indenture, dated February 16, 1999, by and between Salton Sea Funding Corporation and Chase Manhattan Bank and Trust Company, National Association (incorporated by reference to Exhibit 4.1(f) to the Salton Sea Funding Corporation Registration Statement No. 333-79581 dated June 29, 1999).
4.70	Sixth Supplemental Indenture, dated June 29, 1999, by and between Salton Sea Funding Corporation and Chase Manhattan Bank and Trust Company, National Association (incorporated by reference to Exhibit 4.1(g) to the Salton Sea Funding Corporation Registration Statement No. 333-79581 dated June 29, 1999).
10.1	$1,400,000,000 Credit Agreement, dated as of June 27, 2014, among Berkshire Hathaway Energy Company, as Borrower, the Initial Lenders, Union Bank, N.A., as Administrative Agent and Swingline Lender, and the LC Issuing Banks (incorporated by reference to Exhibit 10.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated June 27, 2014).
10.2	$600,000,000 Credit Agreement, dated as of June 28, 2012, among Berkshire Hathaway Energy Company, as Borrower, the Banks, Financial Institutions and Other Institutional Lenders, as Initial Lenders, Union Bank, N.A, as Administrative Agent and Swingline Lender, and the LC Issuing Banks (incorporated by reference to Exhibit 10.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2012).

Exhibit No.	Description
10.3	£150,000,000 Facility Agreement, dated August 20, 2012, among Northern Powergrid Holdings Company, as Borrower, and Abbey National Treasury Services plc, Lloyds TSB Bank plc and The Royal Bank of Scotland plc, as Original Lenders (incorporated by reference to Exhibit 10.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2012).
10.4	Amended and Restated Credit Agreement, dated as of December 14, 2011, among AltaLink Investments, L.P., as borrower, AltaLink Investment Management Ltd., as general partner, Royal Bank of Canada, as administrative agent, and Lenders (incorporated by reference to Exhibit 10.21 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
10.5	First Amending Agreement to Amended and Restated Credit Agreement, dated as of April 27, 2012, among AltaLink Investments, L.P., as borrower, AltaLink Investment Management Ltd., as general partner, Royal Bank of Canada, as administrative agent, and Lenders (incorporated by reference to Exhibit 10.22 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
10.6	Second Amending Agreement to Amended and Restated Credit Agreement, dated as of December 14, 2012, among AltaLink Investments, L.P., as borrower, AltaLink Investment Management Ltd., as general partner, Royal Bank of Canada, as administrative agent, and Lenders (incorporated by reference to Exhibit 10.23 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
10.7	Third Amending Agreement to Amended and Restated Credit Agreement, dated as of December 16, 2013, among AltaLink Investments, L.P., as borrower, AltaLink Investment Management Ltd., as general partner, Royal Bank of Canada, as administrative agent, and Lenders (incorporated by reference to Exhibit 10.24 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
10.8	Waiver and Fourth Amending Agreement to Amended and Restated Credit Agreement, dated as of October 24, 2014, among AltaLink Investments, L.P., as borrower, AltaLink Investment Management Ltd., as general partner, Royal Bank of Canada, as administrative agent, and Lenders (incorporated by reference to Exhibit 10.25 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
10.9	Fifth Amending Agreement to Amended and Restated Credit Agreement, dated as of December 15, 2014, among AltaLink Investments, L.P., as borrower, AltaLink Investment Management Ltd., as general partner, Royal Bank of Canada, as administrative agent, and Lenders (incorporated by reference to Exhibit 10.26 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
10.10	Third Amended and Restated Credit Agreement, dated as of December 19, 2013, among AltaLink, L.P., as borrower, AltaLink Management Ltd., as general partner, The Bank of Nova Scotia, as administrative agent, and Lenders (incorporated by reference to Exhibit 10.27 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
10.11	First Amending Agreement to Third Amended and Restated Credit Agreement, dated as of October 24, 2014, among AltaLink, L.P., as borrower, AltaLink Management Ltd., as general partner, The Bank of Nova Scotia, as administrative agent, and Lenders (incorporated by reference to Exhibit 10.28 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
10.12	Second Amending Agreement to Third Amended and Restated Credit Agreement, dated as of October 24, 2014, among AltaLink, L.P., as borrower, AltaLink Management Ltd., as general partner, The Bank of Nova Scotia, as administrative agent, and Lenders (incorporated by reference to Exhibit 10.29 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
10.13	Third Amending Agreement to Third Amended and Restated Credit Agreement, dated as of December 18, 2014, among AltaLink, L.P., as borrower, AltaLink Management Ltd., as general partner, The Bank of Nova Scotia, as administrative agent, and Lenders (incorporated by reference to Exhibit 10.30 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).

Exhibit No.	Description
10.14	Second Amended and Restated Credit Agreement, dated as of December 19, 2013, among AltaLink, L.P., as borrower, AltaLink Management Ltd., as general partner, The Bank of Nova Scotia, as agent, and Lenders (incorporated by reference to Exhibit 10.31 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
10.15	First Amending Agreement to Second Amended and Restated Credit Agreement, dated as of October 24, 2014, among AltaLink, L.P., as borrower, AltaLink Management Ltd., as general partner, and The Bank of Nova Scotia, as agent (incorporated by reference to Exhibit 10.32 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
10.16	Second Amending Agreement to Second Amended and Restated Credit Agreement, dated as of December 18, 2014, among AltaLink, L.P., as borrower, AltaLink Management Ltd., as general partner, and The Bank of Nova Scotia, as agent (incorporated by reference to Exhibit 10.33 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
10.17*	Summary of Key Terms of Compensation Arrangements with Berkshire Hathaway Energy Company Named Executive Officers and Directors.
10.18*	Amended and Restated Employment Agreement, dated February 25, 2008, by and between MidAmerican Energy Holdings Company and Gregory E. Abel (incorporated by reference to Exhibit 10.3 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2007).
10.19*	Incremental Profit Sharing Plan, dated February 27, 2014, by and between Berkshire Hathaway Energy Company and Gregory E. Abel (incorporated by reference to Exhibit 10.2 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2013).
10.20*	Amended and Restated Employment Agreement, dated February 25, 2008, by and between MidAmerican Energy Holdings Company and Patrick J. Goodman (incorporated by reference to Exhibit 10.5 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2007).
10.21*	CalEnergy Company, Inc. Voluntary Deferred Compensation Plan, effective December 1, 1997, First Amendment, dated as of August 17, 1999, and Second Amendment effective March 14, 2000 (incorporated by reference to Exhibit 10.50 to the MidAmerican Energy Holdings Company Registration Statement No. 333-101699 dated December 6, 2002).
10.22*	Berkshire Hathaway Energy Company Executive Voluntary Deferred Compensation Plan restated effective as of January 1, 2007 (incorporated by reference to Exhibit 10.9 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2007).
10.23*	MidAmerican Energy Company First Amended and Restated Supplemental Retirement Plan for Designated Officers dated as of May 10, 1999 amended on February 25, 2008 to be effective as of January 1, 2005 (incorporated by reference to Exhibit 10.10 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2007).
10.24*	Berkshire Hathaway Energy Company Long-Term Incentive Partnership Plan as Amended and Restated January 1, 2014 (incorporated by reference to Exhibit 10.9 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2014).
14.1	Berkshire Hathaway Energy Company Code of Ethics For Chief Executive Officer, Chief Financial Officer and Other Covered Officers.
21.1	Subsidiaries of the Registrant.
23.1	Consent of Deloitte & Touche LLP.
24.1	Power of Attorney.
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.

Exhibit No.	Description
PACIFICORP	
3.4	Third Restated Articles of Incorporation of PacifiCorp (incorporated by reference to Exhibit (3)a to the PacifiCorp Annual Report on Form 10-K for the year ended December 31, 1996).
3.5	Bylaws of PacifiCorp, as amended May 23, 2005 (incorporated by reference to Exhibit 3.2 to the PacifiCorp Annual Report on Form 10-K for the year ended March 31, 2005).
10.25*	Summary of Key Terms of Compensation Arrangements with PacifiCorp's Named Executive Officers and Directors.
10.26*	PacifiCorp Executive Voluntary Deferred Compensation Plan (incorporated by reference to Exhibit 10.3 to the PacifiCorp Annual Report on Form 10-K for the year ended December 31, 2007).
10.27*	Supplemental Executive Retirement Plan (incorporated by reference to Exhibit 10.7 to the PacifiCorp Annual Report on Form 10-K for the year ended March 31, 2005).
10.28*	Amendment No. 10 to PacifiCorp Supplemental Executive Retirement Plan dated June 2, 2006 (incorporated by reference to Exhibit 10.5 to the PacifiCorp Quarterly Report on Form 10-Q for the quarter ended June 30, 2006).
10.29*	Amendment No. 11 to PacifiCorp Supplemental Executive Retirement Plan dated June 2, 2006 (incorporated by reference to Exhibit 10.6 to the PacifiCorp Quarterly Report on Form 10-Q for the quarter ended June 30, 2006).
10.30*	Amendment No. 1 to the PacifiCorp Executive Voluntary Deferred Compensation Plan dated October 28, 2008 (incorporated by reference to Exhibit 10.10 to the PacifiCorp Annual Report on Form 10-K for the year ended December 31, 2009).
10.31*	Amendment No. 2 to the PacifiCorp Executive Voluntary Deferred Compensation Plan dated October 16, 2012 (incorporated by reference to Exhibit 10.11 to the PacifiCorp Annual Report on Form 10-K for the year ended December 31, 2012).
10.32*	PacifiCorp Long-Term Incentive Partnership Plan effective January 1, 2014 (incorporated by reference to Exhibit 10.10 to the PacifiCorp Annual Report on Form 10-K for the year ended December 31, 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.
14.2	Code of Ethics (incorporated by reference to Exhibit 14.1 to the PacifiCorp Transition Report on Form 10-K for the nine-month period ended December 31, 2006).
23.2	Consent of Deloitte & Touche LLP.
31.3	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.4	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.3	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.4	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Exhibit No.	**Description**

BERKSHIRE HATHAWAY ENERGY AND PACIFICORP

4.71 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 to the PacifiCorp Form 8-B, as supplemented and modified by 28 Supplemental Indentures, each incorporated by reference, as follows:

Exhibit Number	PacifiCorp File Type	File Date
(4)(b)	SE	November 2, 1989
(4)(a)	8-K	January 9, 1990
4(a)	8-K	September 11, 1991
4(a)	8-K	January 7, 1992
4(a)	10-Q	Quarter ended March 31, 1992
4(a)	10-Q	Quarter ended September 30, 1992
4(a)	8-K	April 1, 1993
4(a)	10-Q	Quarter ended September 30, 1993
(4)b	10-Q	Quarter ended June 30, 1994
(4)b	10-K	Year ended December 31, 1994
(4)b	10-K	Year ended December 31, 1995
(4)b	10-K	Year ended December 31, 1996
(4)b	10-K	Year ended December 31, 1998
99(a)	8-K	November 21, 2001
4.1	10-Q	Quarter ended June 30, 2003
99	8-K	September 8, 2003
4	8-K	August 24, 2004
4	8-K	June 13, 2005
4.2	8-K	August 14, 2006
4	8-K	March 14, 2007
4.1	8-K	October 3, 2007
4.1	8-K	July 17, 2008
4.1	8-K	January 8, 2009
4.1	8-K	May 12, 2011
4.1	8-K	January 6, 2012
4.1	8-K	June 6, 2013
4.1	8-K	March 13, 2014
4.1	8-K	June 19, 2015

10.33 $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 (incorporated by reference to Exhibit 10.1 to the PacifiCorp Quarterly Report on Form 10-Q for the quarter ended June 30, 2012).

10.34 $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 (incorporated by reference to Exhibit 10.1 to the PacifiCorp Quarterly Report on Form 10-Q for the quarter ended March 31, 2013).

95 Mine Safety Disclosures Required by the Dodd-Frank Wall Street Reform and Consumer Protection Act.

Exhibit No.	Description
MIDAMERICAN ENERGY	
3.6	Restated Articles of Incorporation of MidAmerican Energy Company, as amended October 27, 1998. (incorporated by reference to Exhibit 3.3 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended September 30, 1998).
3.7	Restated Bylaws of MidAmerican Energy Company, as amended July 24, 1996. (incorporated by reference to Exhibit 3.1 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 1996).
14.3	Code of Ethics for Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer. (incorporated by reference to Exhibit 14.1 to the MidAmerican Energy Company Annual Report on Form 10-K for the year ended December 31, 2003).
23.3	Consent of Deloitte & Touche LLP.
31.5	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.6	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.5	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.6	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
MIDAMERICAN FUNDING	
3.8	Articles of Organization of MidAmerican Funding, LLC (incorporated by reference to Exhibit 3.1 to the MidAmerican Funding, LLC Registration Statement No. 333-90553 dated November 8, 1999).
3.9	Operating Agreement of MidAmerican Funding, LLC (incorporated by reference to Exhibit 3.2 to the MidAmerican Funding, LLC Registration Statement No. 333-90553 dated November 8, 1999).
3.10	Amendment No. 1 to the Operating Agreement of MidAmerican Funding, LLC dated as of February 9, 2010 (incorporated by reference to Exhibit 3.3 to the MidAmerican Funding, LLC Annual Report on Form 10-K for the year ended December 31, 2010).
14.4	Code of Ethics for Chief Executive Officer, Chief Financial Officer and Chief Accounting Officer (incorporated by reference to Exhibit 14.2 to the MidAmerican Funding, LLC Annual Report on Form 10-K for the year ended December 31, 2003).
31.7	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.8	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.7	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.8	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
BERKSHIRE HATHAWAY ENERGY, MIDAMERICAN ENERGY AND MIDAMERICAN FUNDING	
4.72	Form of Indenture, by and between MidAmerican Energy Company and The Bank of New York, Trustee (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Registration Statement No. 333-59760 dated January 31, 2002).
4.73	First Supplemental Indenture, dated as of February 8, 2002, by and between MidAmerican Energy Company and The Bank of New York, Trustee (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Company Annual Report on Form 10-K for the year ended December 31, 2004).
4.74	Fourth Supplemental Indenture, dated November 1, 2005, by and between MidAmerican Energy Company and The Bank of New York Trust Company, NA, Trustee (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Annual Report on Form 10-K for the year ended December 31, 2005).
4.75	Indenture, dated as of October 1, 2006, by and between MidAmerican Energy Company and The Bank of New York Trust Company, N.A., Trustee (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2006).

Exhibit No.	Description
4.76	First Supplemental Indenture, dated as of October 6, 2006, by and between MidAmerican Energy Company and The Bank of New York Trust Company, N.A., Trustee relating to the 5.80% Notes due 2036 (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2006).
4.77	Second Supplemental Indenture, dated June 29, 2007, by and between MidAmerican Energy Company and The Bank of New York Trust Company, N.A., Trustee relating to the 5.95% Notes due 2017 (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Current Report on Form 8-K dated June 29, 2007).
4.78	Third Supplemental Indenture, dated March 25, 2008, by and between MidAmerican Energy Company and The Bank of New York Trust Company, Trustee, relating to the 5.30% Notes due 2018 (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Current Report on Form 8-K dated March 25, 2008).
4.79	Indenture, dated as of September 9, 2013, between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Current Report on Form 8-K dated September 13, 2013).
4.80	First Supplemental Indenture, dated as of September 19, 2013, between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., as trustee (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Current Report on Form 8-K dated September 19, 2013).
4.81	Specimen of 2.40% First Mortgage Bonds due 2019 (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Current Report on Form 8-K dated September 19, 2013).
4.82	Specimen of 3.70% First Mortgage Bonds due 2023 (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Company Current Report on Form 8-K dated September 19, 2013).
4.83	Specimen of 4.80% First Mortgage Bonds due 2043 (incorporated by reference to Exhibit 4.4 to the MidAmerican Energy Company Current Report on Form 8-K dated September 19, 2013).
4.84	Amendment No. 1 to the First Supplemental Indenture, dated as of April 3, 2014, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Current Report on Form 8-K dated April 3, 2014).
4.85	Second Supplemental Indenture, dated as of April 3, 2014, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Current Report on Form 8-K dated April 3, 2014).
4.86	Specimen of 3.50% First Mortgage Bonds due 2024 (incorporated by reference to Exhibit 4.4 to the MidAmerican Energy Company Current Report on Form 8-K dated April 3, 2014).
4.87	Specimen of 4.40% First Mortgage Bonds due 2044 (incorporated by reference to Exhibit 4.5 to the MidAmerican Energy Company Current Report on Form 8-K dated April 3, 2014).
4.88	Amendment No. 1 to the Second Supplemental Indenture, dated as of October 15, 2015, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Current Report on Form 8-K dated October 15, 2015).
4.89	Third Supplemental Indenture, dated as of October 15, 2015, by and between MidAmerican Energy Company and The Bank of New York Mellon Trust Company, N.A., to the Indenture dated as of September 9, 2013 (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Current Report on Form 8-K dated October 15, 2015).
4.90	Specimen of 3.50% First Mortgage Bonds due 2024 (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Company Current Report on Form 8-K dated October 15, 2015).
4.91	Specimen of 4.25% First Mortgage Bonds due 2046 (incorporated by reference to Exhibit 4.5 to the MidAmerican Energy Company Current Report on Form 8-K dated October 15, 2015).

Exhibit No.	Description
4.92	Mortgage, Security Agreement, Fixture Filing and Financing Statement, dated as of September 9, 2013, from MidAmerican Energy Company to The Bank of New York Mellon Trust Company, N.A., as collateral trustee (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Current Report on Form 8-K dated September 13, 2013).
4.93	Intercreditor and Collateral Trust Agreement, dated as of September 9, 2013, among MidAmerican Energy Company, The Bank of New York Mellon Trust Company, N.A., as trustee, and The Bank of New York Mellon Trust Company, N.A., as collateral trustee (incorporated by reference to Exhibit 4.3 to the MidAmerican Energy Company Current Report on Form 8-K dated September 13, 2013).
4.94	Form of Indenture, between MidAmerican Energy Company and the Trustee, (Senior Unsecured Debt Securities) (incorporated by reference to Exhibit 4.1 to the MidAmerican Energy Company Registration Statement No. 333-192077 dated November 4, 2013).
4.95	Form of Indenture, between MidAmerican Energy Company and the Trustee, (Subordinated Unsecured Debt Securities) (incorporated by reference to Exhibit 4.2 to the MidAmerican Energy Company Registration Statement No. 333-192077 dated November 4, 2013).
10.35	$600,000,000 Credit Agreement, dated as of March 27, 2013, among MidAmerican Energy Company, 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 (incorporated by reference to Exhibit 10.1 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2013).
10.36	Iowa Utilities Board Order Approving Settlement With Modifications, issued December 21, 2001, in regards to MidAmerican Energy Company (incorporated by reference to Exhibit 10.7 to the MidAmerican Energy Company Annual Report on Form 10-K for the year ended December 31, 2001).
10.37	Stipulation and Agreement in Regard to MidAmerican Energy Company Ratemaking Principles for Wind Energy Investment, approved by the Iowa Utilities Board on October 17, 2003 (incorporated by reference to Exhibit 10 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2003).
10.38	Stipulation and Agreement Dated December 20, 2004, in Regard to MidAmerican Energy Company Ratemaking Principles for the 2005 Wind Expansion Project, approved by the Iowa Utilities Board on January 31, 2005 (incorporated by reference to Exhibit 10.2 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2006).
10.39	Stipulation and Agreement Dated December 14, 2005, in Regard to MidAmerican Energy Company Ratemaking Principles for the 2006-2007 Wind Expansion Project, approved by the Iowa Utilities Board on April 18, 2006 (incorporated by reference to Exhibit 10.3 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2006).
10.40	Stipulation and Agreement Dated March 23, 2007, in Regard to MidAmerican Energy Company Ratemaking Principles for “Wind IV Iowa Projects”, approved by the Iowa Utilities Board on July 27, 2007 (incorporated by reference to Exhibit 10.1 to the MidAmerican Energy Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2007).

BERKSHIRE HATHAWAY ENERGY AND MIDAMERICAN FUNDING

4.96	Indenture and First Supplemental Indenture, dated March 11, 1999, by and between MidAmerican Funding, LLC and IBJ Whitehall Bank & Trust Company, Trustee, relating to the $325 million Senior Bonds (incorporated by reference to Exhibits 4.1 and 4.2 to the MidAmerican Funding, LLC Registration Statement No. 333-905333 dated November 8, 1999).

NEVADA POWER

3.11	Restated Articles of Incorporation of Nevada Power Company, dated July 28, 1999 (incorporated by reference to Exhibit 3(B) to the Nevada Power Company Annual Report on Form 10-K for the year ended December 31, 1999).

Exhibit No.	Description
3.12	Amended and Restated By-Laws of Nevada Power Company dated July 28, 1999 (incorporated by reference to Exhibit 3(C) to the Nevada Power Company Annual Report on Form 10-K for the year ended December 31, 1999).
10.41	Transmission Use and Capacity Exchange Agreement between Nevada Power Company, Sierra Pacific Power Company and Great Basin Transmission, LLC dated August 20, 2010 (incorporated by reference to Exhibit 10.1 to the Nevada Power Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2010).
10.42	Financing Agreement between Clark County, Nevada and Nevada Power Company, dated August 1, 2006 (relating to Clark County, Nevada $39,500,000 Pollution Control Refund Revenue Bonds Series 2006) (incorporated by reference to Exhibit 10.1 to the Nevada Power Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2006).
10.43	Financing Agreement between Coconino County, Arizona Pollution Control Corporation and Nevada Power Company, dated August 1, 2006 (relating to Coconino County, Arizona $13,000,000 Pollution Control Corporation Refunding Revenue Bonds Series 2006B) (incorporated by reference to Exhibit 10.3 to the Nevada Power Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2006).
10.44	Financing Agreement between Coconino County, Arizona Pollution Control Corporation and Nevada Power Company, dated August 1, 2006 (relating to Coconino County, Arizona $40,000,000 Pollution Control Corporation Refunding Revenue Bonds Series 2006A) (incorporated by reference to Exhibit 10.2 to the Nevada Power Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2006).
12.3	Computation of Ratios of Earnings to Fixed Charges.
14.5	Code of Ethics for Chief Executive Officer, Chief Financial Officer and Other Covered Officers (incorporated by reference to Exhibit 14.1 to the Nevada Power Company Annual Report on Form 10-K for the year ended December 31, 2013).
23.4	Consent of Deloitte & Touche LLP.
31.9	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.10	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.9	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.10	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

BERKSHIRE HATHAWAY ENERGY AND NEVADA POWER

4.97	General and Refunding Mortgage Indenture, dated May 1, 2001, between Nevada Power Company and The Bank of New York, as Trustee (incorporated by reference to Exhibit 4.1(a) to the Nevada Power Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2001).
4.98	Officer's Certificate establishing the terms of Nevada Power Company's 5.95% General and Refunding Mortgage Notes, Series M, due 2016 (incorporated by reference to Exhibit 4(A) to the Nevada Power Company Annual Report on Form 10-K for the year ended December 31, 2005).
4.99	Form of Nevada Power Company's 5.95% General and Refunding Mortgage Notes, Series M, due 2016 (incorporated by reference to Exhibit 4(B) to the Nevada Power Company Quarterly Report on Form 10-Q for the year ended December 31, 2005).
4.100	Officer's Certificate establishing the terms of Nevada Power Company's 6.650% General and Refunding Mortgage Notes, Series N, due 2036 (incorporated by reference to Exhibit 4.1 to the Nevada Power Company Form 10-Q for the quarter ended March 31, 2006).
4.101	Officer's Certificate establishing the terms of Nevada Power Company's 6.50% General and Refunding Mortgage Notes, Series O, due 2018 (incorporated by reference to Exhibit 4.7 to the Nevada Power Company Registration Statement No. 333-134801 dated June 7, 2006).

Exhibit No.	Description
4.102	Officer's Certificate establishing the terms of Nevada Power Company's 6.750% General and Refunding Mortgage Notes, Series R, due 2037 (incorporated by reference to Exhibit 4.1 to the Nevada Power Company Current Report on Form 8-K dated June 27, 2007).
4.103	Officer's Certificate establishing the terms of Nevada Power Company's 6.50% General and Refunding Mortgage Notes, Series S, due 2018 (incorporated by reference to Exhibit 4.1 to the Nevada Power Company Current Report on Form 8-K dated July 28, 2008).
4.104	Officer's Certificate establishing the terms of Nevada Power Company d/b/a NV Energy's 7.125% General and Refunding Mortgage Notes, Series V, due 2019 (incorporated by reference to Exhibit 4.1 to the Nevada Power Company Current Report on Form 8-K dated February 26, 2009).
4.105	Officer's Certificate establishing the terms of Nevada Power Company d/b/a NV Energy's 5.375% General and Refunding Mortgage Notes, Series X, due 2040 (incorporated by reference to Exhibit 4.1 to Nevada Power Company Current Report on Form 8-K dated September 10, 2010).
4.106	Officer's Certificate establishing the terms of Nevada Power Company d/b/a NV Energy's 5.45% General and Refunding Mortgage Notes, Series Y, due 2041 (incorporated by reference to Exhibit 4.1 to the Nevada Power Company Current Report on Form 8-K dated May 10, 2011).
10.45	Credit Agreement dated March 23, 2012 between Nevada Power Company d/b/a NV Energy and Wells Fargo Bank, N.A., as administrative agent for the lenders (incorporated by reference to Exhibit 10.1 to the Nevada Power Company Quarterly Report on Form 10-Q for the quarter ended March 30, 2012).
10.46	$400,000,000 Amended and Restated Credit Agreement, dated as of June 27, 2014, among Nevada Power Company, as Borrower, the Initial Lenders, Wells Fargo Bank, National Association, as Administrative Agent and Swingline Lender, and the LC Issuing Banks (incorporated by reference to Exhibit 10.1 to the Nevada Power Company Current Report on Form 8-K dated June 27, 2014).

SIERRA PACIFIC

3.13	Restated Articles of Incorporation of Sierra Pacific Power Company, dated October 25, 2006 (incorporated by reference to Exhibit 3.1 to the Sierra Pacific Power Company Quarterly Report on Form 10-Q for quarter ended September 30, 2006).
3.14	By-Laws of Sierra Pacific Power Company, as amended through November 13, 1996 (incorporated by reference to Exhibit (3)(A) to the Sierra Pacific Power Company Annual Report on Form 10-K for the year ended December 31, 1996).
10.47	Transmission Use and Capacity Exchange Agreement between Nevada Power Company, Sierra Pacific Power Company and Great Basin Transmission, LLC dated August 20, 2010 (incorporated by reference to Exhibit 10.1 to the Sierra Pacific Power Company Quarterly Report on Form 10-Q for the quarter ended September 30, 2010).
10.48	Financing Agreement dated April 1, 2007 between Washoe County and Sierra Pacific Power Company (relating to Washoe County, Nevada $40,000,000 Water Facilities Control Refunding Revenue Bonds (Sierra Pacific Power Company Project) Series 2007A) (incorporated by reference to Exhibit 10.1 to the Sierra Pacific Power Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2007).
10.49	Financing Agreement dated April 1, 2007 between Washoe County and Sierra Pacific Power Company (relating to Washoe County, Nevada $40,000,000 Water Facilities Control Refunding Revenue Bonds (Sierra Pacific Power Company Project) Series 2007B) (incorporated by reference to Exhibit 10.2 to the Sierra Pacific Power Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2007).
10.50	Financing Agreement dated November 1, 2006 between Humboldt County, Nevada and Sierra Pacific Power Company dated November 1, 2006 (relating to Humboldt County, Nevada $49,750,000 Pollution Control Refunding Revenue Bonds (Sierra Pacific Power Company Project) Series 2006) (incorporated by reference to Exhibit 10(B) to the Sierra Pacific Power Company Annual Report on Form 10-K for the year ended December 31, 2006).

Exhibit No.	Description
10.51	Financing Agreement dated November 1, 2006 between Washoe County, Nevada and Sierra Pacific Power Company dated November 1, 2006 (relating to Washoe County, Nevada $58,750,000 Gas Facilities Control Refunding Revenue Bonds (Sierra Pacific Power Company Project) Series 2006A) (incorporated by reference to Exhibit 10(C) to the Sierra Pacific Power Company Annual Report on Form 10-K for the year ended December 31, 2006).
10.52	Financing Agreement dated November 1, 2006 between Washoe County, Nevada and Sierra Pacific Power Company dated November 1, 2006 (relating to Washoe County, Nevada $75,000,000 Water Facilities Control Refunding Revenue Bonds (Sierra Pacific Power Company Project) Series 2006B) (incorporated by reference to Exhibit 10(D) to the Sierra Pacific Power Company Annual Report on Form 10-K for the year ended December 31, 2006).
10.53	Financing Agreement dated November 1, 2006 between Washoe County, Nevada and Sierra Pacific Power Company dated November 1, 2006 (relating to Washoe County, Nevada $84,800,000 Gas and Water Facilities Control Refunding Revenue Bonds (Sierra Pacific Power Company Project) Series 2006C) (incorporated by reference to Exhibit 10(E) to the Sierra Pacific Power Company Quarterly Report on Form 10-K for the year ended December 31, 2006).
12.4	Computation of Ratios of Earnings to Fixed Charges.
14.6	Code of Ethics for Chief Executive Officer, Chief Financial Officer and Other Covered Officers (incorporated by reference to Exhibit 14.1 to the Sierra Pacific Power Company Annual Report on Form 10-K for the year ended December 31, 2013).
23.5	Consent of Deloitte & Touche LLP.
31.11	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.12	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.11	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.12	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

BERKSHIRE HATHAWAY ENERGY AND SIERRA PACIFIC

4.107	General and Refunding Mortgage Indenture, dated as of May 1, 2001, between Sierra Pacific Power Company and The Bank of New York, as Trustee (incorporated by reference to Exhibit 4.2(a) to the Sierra Pacific Power Company Quarterly Report on Form 10-Q for the quarter ended June 30, 2001).
4.108	Second Supplemental Indenture, dated as of October 30, 2006, to subject additional properties of Sierra Pacific Power Company located in the State of California to the lien of the General and Refunding Mortgage Indenture and to correct defects in the original Indenture (incorporated by reference to Exhibit 4(A) to the Sierra Pacific Power Company Annual Report on Form 10-K for the year ended December 31, 2006).
4.109	Officer's Certificate establishing the terms of Sierra Pacific Power Company's 6% General and Refunding Mortgage Notes, Series M, due 2016 (incorporated by reference to Exhibit 4.4 to the Sierra Pacific Power Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2006).
4.110	Form of First Supplemental Officer's Certificate establishing the terms of Sierra Pacific Power Company's 6% General and Refunding Mortgage Notes, Series M, due 2016 (incorporated by reference to Exhibit 4.2 to the Sierra Pacific Power Company Current Report on Form 8-K dated August 18, 2009).
4.111	Officer's Certificate establishing the terms of Sierra Pacific Power Company's 6.750% General and Refunding Mortgage Notes, Series P, due 2037 (incorporated by reference to Exhibit 4.2 to the Sierra Pacific Power Company Current Report on Form 8-K dated June 27, 2007).
4.112	Officer’s Certificate establishing the terms of Sierra Pacific Power Company's 3.375% General and Refunding Mortgage Notes, Series T, due 2023 (incorporated by reference to Exhibit 4.1 to the Sierra Pacific Power Company Current Report on Form 8-K dated August 14, 2013).
10.54	Credit Agreement dated March 23, 2012 between Sierra Pacific Power Company d/b/a NV Energy and Wells Fargo Bank, N.A., as administrative agent for the lenders (filed as Exhibit 10.2 to Form 10-Q for the quarter ended March 30, 2012).

Exhibit No.	Description
10.55	$250,000,000 Amended and Restated Credit Agreement, dated as of June 27, 2014, among Sierra Pacific Power Company, as Borrower, the Initial Lenders, Wells Fargo Bank, National Association, as Administrative Agent and Swingline Lender, and the LC Issuing Banks (incorporated by reference to Exhibit 10.1 to the Sierra Pacific Power Company Current Report on Form 8-K dated June 27, 2014).
ALL REGISTRANTS	
101	The following financial information from each respective Registrant's Annual Report on Form 10-K for the year ended December 31, 2015 is formatted in XBRL (eXtensible Business Reporting Language) and included herein: (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Operations, (iii) the Consolidated Statements of Comprehensive Income, (iv) the Consolidated Statements of Changes in Equity, (v) the Consolidated Statements of Cash Flows and (vi) the Notes to Consolidated Financial Statements, tagged in summary and detail.

* Management contract or compensatory plan.

Pursuant to Item 601(b)(4)(iii)(A) of Regulation S-K, each Registrant has not filed as an exhibit to this Form 10-K certain instruments with respect to long-term debt not registered in which the total amount of securities authorized thereunder does not exceed 10% of the total assets of the respective Registrant. Each Registrant hereby agrees to furnish a copy of any such instrument to the Commission upon request.

EXHIBIT 12.1

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

	Years Ended December 31,				
	2015	2014	2013	2012	2011
Earnings Available for Fixed Charges:					
Income from continuing operations before income tax expense	$ 1,023	$ 1,007	$ 979	$ 734	$ 768
Fixed charges	384	384	385	385	397
Total earnings available for fixed charges	$ 1,407	$ 1,391	$ 1,364	$ 1,119	$ 1,165
Fixed Charges:					
Interest expense	$ 379	$ 379	$ 379	$ 380	$ 392
Estimated interest portion of rentals charged to expense	5	5	6	5	5
Total fixed charges	$ 384	$ 384	$ 385	$ 385	$ 397
Ratio of Earnings to Fixed Charges	3.7x	3.6x	3.5x	2.9x	2.9x

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,				
	2015	2014	2013	2012	2011
Earnings Available for Fixed Charges:					
Income from continuing operations before income tax expense	$ 1,023	$ 1,007	$ 979	$ 734	$ 768
Fixed charges	384	384	385	385	397
Total earnings available for fixed charges	$ 1,407	$ 1,391	$ 1,364	$ 1,119	$ 1,165
Fixed Charges and Preferred Stock Dividends:					
Interest expense	$ 379	$ 379	$ 379	$ 380	$ 392
Estimated interest portion of rentals charged to expense	5	5	6	5	5
Total fixed charges	384	384	385	385	397
Preferred stock dividends (1)	—	—	2	3	3
Total fixed charges and preferred stock dividends	$ 384	$ 384	$ 387	$ 388	$ 400
Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends	3.7x	3.6x	3.5x	2.9x	2.9x

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

EXHIBIT 12.3

NEVADA POWER COMPANY
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(Dollars in millions)

	Years Ended December 31,				
	2015	**2014**	**2013**	**2012**	**2011**
Earnings available for fixed charges:					
Net income	$ 288	$ 227	$ 145	$ 258	$ 133
Add (deduct):					
Income tax expense	162	130	94	138	71
Fixed charges	190	211	220	220	234
Capitalized interest (allowance for borrowed funds used during construction)	(3)	(1)	(6)	(5)	(7)
	349	340	308	353	298
Total earnings available for fixed charges	$ 637	$ 567	$ 453	$ 611	$ 431
Fixed charges -					
Interest expense	190	211	220	220	234
Total fixed charges	$ 190	$ 211	$ 220	$ 220	$ 234
Ratio of earnings to fixed charges	3.4x	2.7x	2.1x	2.8x	1.8x

EXHIBIT 12.4

SIERRA PACIFIC POWER COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES
(Dollars in Millions)

	Years Ended December 31,				
	2015	**2014**	**2013**	**2012**	**2011**
Earnings available for fixed charges:					
Net income	$ 83	$ 87	$ 55	$ 84	$ 60
Add (deduct):					
Income tax expense	47	47	33	40	31
Fixed charges	61	63	62	66	70
Capitalized interest (allowance for borrowed funds used during construction)	(2)	(2)	(2)	(2)	(2)
	106	108	93	104	99
Total earnings available for fixed charges	$ 189	$ 195	$ 148	$ 188	$ 159
Fixed charges -					
Interest expense	61	63	62	66	70
Total fixed charges	$ 61	$ 63	$ 62	$ 66	$ 70
Ratio of earnings to fixed charges	3.1x	3.1x	2.4x	2.8x	2.3x

EXHIBIT 21.1

BERKSHIRE HATHAWAY ENERGY COMPANY
SUBSIDIARIES AND JOINT VENTURES

Pursuant to Item 601(b)(21)(ii) of Regulation S-K, we have omitted certain subsidiaries (all of which, when considered in the aggregate as a single subsidiary, would not constitute a significant subsidiary as of the end of our last fiscal year).

PPW Holdings LLC	Delaware
PacifiCorp	Oregon
MidAmerican Funding, LLC	Iowa
MHC Inc.	Iowa
MidAmerican Energy Company	Iowa
NVE Holdings, LLC	Delaware
NV Energy, Inc.	Nevada
Nevada Power Company d/b/a NV Energy	Nevada
Sierra Pacific Power Company d/b/a NV Energy	Nevada
Northern Powergrid Holdings Company	England
Northern Powergrid U.K. Holdings	England
Northern Powergrid Limited	England
Northern Electric plc.	England
Northern Powergrid (Northeast) Limited	England
Yorkshire Power Group Limited	England
Yorkshire Electricity Group plc.	England
Northern Powergrid (Yorkshire) plc.	England
NNGC Acquisition, LLC	Delaware
Northern Natural Gas Company	Delaware
KR Holding, LLC	Delaware
Kern River Gas Transmission Company	Texas
BHE Canada, LLC	Delaware
BHE Canada Holdings Corporation	British Columbia
BHE AltaLink Ltd.	Canada
AltaLink Holdings, L.P.	Canada
AltaLink Investments, L.P.	Canada
AltaLink, L.P.	Canada
BHE U.S. Transmission, LLC	Delaware
BHE Renewables, LLC	Delaware
HomeServices of America, Inc.	Delaware

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-147957 on Form S-8 of our report dated February 26, 2016, relating to the consolidated financial statements and financial statement schedules of Berkshire Hathaway Energy Company and subsidiaries, appearing in this Annual Report on Form 10-K of Berkshire Hathaway Energy Company for the year ended December 31, 2015.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 26, 2016

EXHIBIT 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-207687 on Form S-3 of our report dated February 26, 2016, 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, 2015.

/s/ Deloitte & Touche LLP

Portland, Oregon
February 26, 2016

EXHIBIT 23.3

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-206980 on Form S-3 of our report dated February 26, 2016, relating to the financial statements and financial statement schedule of MidAmerican Energy Company, appearing in this Annual Report on Form 10-K of MidAmerican Energy Company for the year ended December 31, 2015.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 26, 2016

EXHIBIT 23.4

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-190869-02 on Form S-3 of our report dated February 26, 2016 relating to the consolidated financial statements of Nevada Power Company and subsidiaries appearing in this Annual Report on Form 10-K of Nevada Power Company for the year ended December 31, 2015.

/s/ Deloitte & Touche LLP

Las Vegas, Nevada
February 26, 2016

EXHIBIT 23.5

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-190869-01 on Form S-3 of our report dated February 26, 2016 relating to the consolidated financial statements of Sierra Pacific Power Company and subsidiaries appearing in this Annual Report on Form 10-K of Sierra Pacific Power Company for the year ended December 31, 2015.

/s/ Deloitte & Touche LLP

Las Vegas, Nevada
February 26, 2016

EXHIBIT 24.1

POWER OF ATTORNEY

The undersigned, a member of the Board of Directors or an officer of BERKSHIRE HATHAWAY ENERGY COMPANY, an Iowa corporation (the "Company"), hereby constitutes and appoints Douglas L. Anderson and Paul J. Leighton and each of them, as his/her true and lawful attorney-in-fact and agent, with full power of substitution and resubstitution, for and in his/her stead, in any and all capacities, to sign on his/her behalf the Company's Annual Report on Form 10-K for the fiscal year ending December 31, 2015 and to execute any amendments thereto and to file the same, with all exhibits thereto, and all other documents in connection therewith, with the Securities and Exchange Commission and applicable stock exchanges, with the full power and authority to do and perform each and every act and thing necessary or advisable to all intents and purposes as he/she might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent, or his/her substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Executed as of February 26, 2016

/s/ Gregory E. Abel
GREGORY E. ABEL

/s/ Patrick J. Goodman
PATRICK J. GOODMAN

/s/ Warren E. Buffett
WARREN E. BUFFETT

/s/ Marc D. Hamburg
MARC D. HAMBURG

/s/ Walter Scott, Jr.
WALTER SCOTT, JR.

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 Berkshire Hathaway Energy Company;

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

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

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) 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 26, 2016

/s/ Gregory E. Abel
Gregory E. Abel
Chairman, President and Chief Executive Officer
(principal executive officer)

EXHIBIT 31.2

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

I, Patrick J. Goodman, certify that:

1. I have reviewed this Annual Report on Form 10-K of Berkshire Hathaway Energy Company;

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

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

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) 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 26, 2016

/s/ Patrick J. Goodman
Patrick J. Goodman
Executive Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 31.3

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 26, 2016

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

EXHIBIT 31.4

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

I, Nikki L. Kobliha, 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 26, 2016

/s/ Nikki L. Kobliha
Nikki L. Kobliha
Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 31.5

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

I, William J. Fehrman, certify that:

1. I have reviewed this annual report on Form 10-K of MidAmerican Energy Company;

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

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

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal controls 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 26, 2016

/s/ William J. Fehrman
William J. Fehrman
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 31.6

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

I, Thomas B. Specketer, certify that:

1. I have reviewed this annual report on Form 10-K of MidAmerican Energy Company;

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

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

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal controls 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 26, 2016

/s/ Thomas B. Specketer
Thomas B. Specketer
Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 31.7

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

I, William J. Fehrman, certify that:

1. I have reviewed this annual report on Form 10-K of MidAmerican Funding, LLC;

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 controls 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 26, 2016

/s/ William J. Fehrman
William J. Fehrman
President
(principal executive officer)

EXHIBIT 31.8

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

I, Thomas B. Specketer, certify that:

1. I have reviewed this annual report on Form 10-K of MidAmerican Funding, LLC;

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 controls 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 26, 2016

/s/ Thomas B. Specketer
Thomas B. Specketer
Vice President and Controller
(principal financial officer)

EXHIBIT 31.9

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

I, Paul J. Caudill, certify that:

1. I have reviewed this Annual Report on Form 10-K of Nevada Power Company (dba NV Energy);

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 26, 2016

/s/ Paul J. Caudill
Paul J. Caudill
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 31.10

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

I, E. Kevin Bethel, certify that:

1. I have reviewed this Annual Report on Form 10-K of Nevada Power Company (dba NV Energy);

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 26, 2016

/s/ E. Kevin Bethel
E. Kevin Bethel
Senior Vice President, Chief Financial Officer and Director
(principal financial officer)

EXHIBIT 31.11

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

I, Paul J. Caudill, certify that:

1. I have reviewed this Annual Report on Form 10-K of Sierra Pacific Power Company (dba NV Energy);

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 26, 2016

/s/ Paul J. Caudill
Paul J. Caudill
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 31.12

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

I, E. Kevin Bethel, certify that:

1. I have reviewed this Annual Report on Form 10-K of Sierra Pacific Power Company (dba NV Energy);

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 26, 2016

/s/ E. Kevin Bethel
E. Kevin Bethel
Senior Vice President, Chief Financial Officer and Director
(principal financial officer)

EXHIBIT 32.1

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

I, Gregory E. Abel, Chairman, President and Chief Executive Officer of Berkshire Hathaway Energy Company (the "Company"), 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, 2015 (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 26, 2016

/s/ Gregory E. Abel
Gregory E. Abel
Chairman, President and Chief Executive Officer
(principal executive officer)

EXHIBIT 32.2

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

I, Patrick J. Goodman, Executive Vice President and Chief Financial Officer of Berkshire Hathaway Energy Company (the "Company"), 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, 2015 (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 26, 2016

/s/ Patrick J. Goodman
Patrick J. Goodman
Executive Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 32.3

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, 2015 (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 26, 2016

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

EXHIBIT 32.4

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

I, Nikki L. Kobliha, 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, 2015 (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 26, 2016

/s/ Nikki L. Kobliha
Nikki L. Kobliha
Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 32.5

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

I, William J. Fehrman, President of MidAmerican Energy Company (the "Company"), 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, 2015 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o (d)); and

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

Date: February 26, 2016

/s/ William J. Fehrman
William J. Fehrman
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 32.6

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

I, Thomas B. Specketer, Vice President and Chief Financial Officer of MidAmerican Energy Company (the "Company"), 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, 2015 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o (d)); and

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

Date: February 26, 2016

/s/ Thomas B. Specketer
Thomas B. Specketer
Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 32.7

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

I, William J. Fehrman, President of MidAmerican Funding, LLC (the "Company"), 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, 2015 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o (d)); and

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

Date: February 26, 2016

/s/ William J. Fehrman
William J. Fehrman
President
(principal executive officer)

EXHIBIT 32.8

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

I, Thomas B. Specketer, Vice President and Controller of MidAmerican Funding, LLC (the "Company"), 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, 2015 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o (d)); and

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

Date: February 26, 2016

/s/ Thomas B. Specketer
Thomas B. Specketer
Vice President and Controller
(principal financial officer)

EXHIBIT 32.9

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

I, Paul J. Caudill, President of Nevada Power Company (dba NV Energy), 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 Nevada Power Company for the annual period ended December 31, 2015 (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 Nevada Power Company.

Date: February 26, 2016

/s/ Paul J. Caudill
Paul J. Caudill
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 32.10

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

I, E. Kevin Bethel, Chief Financial Officer of Nevada Power Company (dba NV Energy), 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 Nevada Power Company for the annual period ended December 31, 2015 (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 Nevada Power Company.

Date: February 26, 2016

/s/ E. Kevin Bethel
E. Kevin Bethel
Senior Vice President, Chief Financial Officer and Director
(principal financial officer)

EXHIBIT 32.11

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

I, Paul J. Caudill, President of Sierra Pacific Power Company (dba NV Energy), 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 Sierra Pacific Power Company for the annual period ended December 31, 2015 (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 Sierra Pacific Power Company.

Date: February 26, 2016

/s/ Paul J. Caudill
Paul J. Caudill
President and Chief Executive Officer
(principal executive officer)

EXHIBIT 32.12

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

I, E. Kevin Bethel, Chief Financial Officer of Sierra Pacific Power Company (dba NV Energy), 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 Sierra Pacific Power Company for the annual period ended December 31, 2015 (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 Sierra Pacific Power Company.

Date: February 26, 2016

/s/ E. Kevin Bethel
E. Kevin Bethel
Senior Vice President, Chief Financial Officer and Director
(principal financial officer)

EXHIBIT 95

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

PacifiCorp and its subsidiaries operate certain coal mines and coal processing facilities (collectively, the "mining facilities") that are regulated by the Federal Mine Safety and Health Administration ("MSHA") under the Federal Mine Safety and Health Act of 1977 (the "Mine Safety Act"). MSHA inspects PacifiCorp's mining facilities on a regular basis. The total number of reportable Mine Safety Act citations, orders, assessments and legal actions for the year ended December 31, 2015 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 if no reportable events occurred at those locations during the year ended December 31, 2015. There were no mining-related fatalities during the year ended December 31, 2015. 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, 2015.

	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[7]	1	—	—	—	—	$ 8	—	—	4
Bridger (surface)	7	—	1	—	—	224	6	5	2
Bridger (underground)	34	—	—	—	1	176	5	10	16
Cottonwood Preparatory Plant[8]	—	—	—	—	—	—	—	—	—
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. The order under Section 104(d) of the Mine Safety Act at Bridger surface mine was reconsidered and subsequently downgraded to a Section 104 (a) non-significant and substantial citation by MSHA.

(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 abated and subsequently terminated by MSHA.

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

(7) The Deer Creek mine is currently idled and closure activities have begun.

(8) The Cottonwood Preparatory Plant was sold in June 2015.