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

FORM 10-K

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

For the fiscal year ended December 31, 2014

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**

Securities registered pursuant to Section 12(b) of the Act: None
Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes ☐ No ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes ☐ No ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

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

All of the shares of common equity of Berkshire Hathaway Energy Company are privately held by a limited group of investors. As of February 18, 2015, 77,391,144 shares of common stock were outstanding.

TABLE OF CONTENTS

Definition of Abbreviations and Industry Terms

When used in Forward-Looking Statements, Part I - Items 1 through 4, Part II - Items 5 through 7A and Items 9 through 9B, and Part III - Items 10 and 14, the following terms have the definitions indicated.

Berkshire Hathaway Energy Company and Related Entities

BHE	Berkshire Hathaway Energy Company
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
Sierra Pacific	Sierra Pacific Power Company
Nevada Utilities	Nevada Power Company and Sierra Pacific Power Company
Northern Powergrid	Northern Powergrid Holdings Company
Northern Natural Gas	Northern Natural Gas Company
Kern River	Kern River Gas Transmission Company
AltaLink	BHE AltaLink Ltd.
ALP	AltaLink, L.P.
BHE U.S. Transmission	BHE U.S. Transmission, LLC (formerly MidAmerican Transmission, LLC)
BHE Renewables, LLC	BHE Renewables, LLC (formerly MidAmerican 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 (formerly MidAmerican 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. and its subsidiaries
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 579-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
CAIR	Clean Air Interstate Rule
CPUC	California Public Utilities Commission
Dodd-Frank Reform Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
Dth	Decatherms
DSM	Demand-side Management
EBA	Energy Balancing Account
ECAM	Energy Cost Adjustment Mechanism
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
IPUC	Idaho Public Utilities Commission
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
NRC	Nuclear Regulatory Commission
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
RTO	Regional Transmission Organization
SEC	United States Securities and Exchange Commission
SIP	State Implementation Plan
TAM	Transition Adjustment Mechanism
UPSC	Utah Public Service Commission
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 Company'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 the Company 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 Company's operations or related industries;
- changes in, and compliance with, environmental laws, regulations, decisions and policies that could, among other items, increase operating and capital costs, reduce 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 Company's ability to recover costs in 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 Company's ability to obtain long-term contracts with customers and suppliers;
- performance and availability of the Company's facilities, including the impacts of 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 Company's 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 Company's significant customers and suppliers;
- changes in business strategy or development plans;
- availability, terms and deployment of capital, including reductions in demand for investment-grade commercial paper, debt securities and other sources of debt financing and volatility in the London Interbank Offered Rate, the base interest rate for BHE's and its subsidiaries' credit facilities;
- changes in BHE's and its subsidiaries' credit ratings;
- risks relating to nuclear generation;
- 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 Company's ability to recover such costs in regulated rates;
- increases in employee healthcare costs, including the implementation of the Affordable Care Act;
- the impact of investment performance and changes in interest rates, legislation, healthcare cost trends, mortality and morbidity on pension and other postretirement benefits expense and funding requirements;
- changes in the residential real estate brokerage and mortgage industries and regulations that could affect brokerage and mortgage transaction levels;
- 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 Company's consolidated financial results;

- the Company's ability to successfully integrate AltaLink and future acquired operations into its business;
- the effects of catastrophic and other unforeseen events, which may be caused by factors beyond the Company's control or by a breakdown or failure of the Company's 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 BHE's filings with the SEC or in other publicly disseminated written documents.

Further details of the potential risks and uncertainties affecting the Company are described in Item 1A and other discussions contained in this Form 10-K. The Company 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 February 18, 2015, 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.

The Company'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. 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, hydro and geothermal sources under long-term contracts, the second-largest residential real estate brokerage firm in the United States, and the second-largest residential real estate brokerage franchise network 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 Midwest United States, in Great Britain and Canada.

- 90% of the Company's consolidated operating income during 2014 was generated from rate-regulated businesses.
- As of December 31, 2014, the Utilities served 4.6 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, 2014, the Company owned approximately 29,200 MW of generation in operation and under construction:
    - Approximately 25,800 MW of generation is owned by its regulated electric utility businesses;
    - Approximately 3,400 MW of generation is owned by our nonregulated subsidiaries, the majority of which provides power to utilities under long-term contracts; and
    - The Company's investment in solar and wind generation in operation and under construction will be $15 billion when completed.
- The Company has approximately 32,100 miles of transmission lines and owns a 50% interest in ETT that has 1,000 miles of transmission lines.
- The BHE Pipeline Group has approximately 16,400 miles of pipeline, a design capacity of approximately 7.8 Bcf of natural gas per day, and transported approximately 8% of the total natural gas consumed in the United States during 2014.
- HomeServices closed over $67.4 billion of home sales in 2014, up 20.2% from 2013, with over 24,000 sales associates and continued to grow its brokerage business. HomeServices' franchise business operates in 49 states with over 440 franchisees throughout the country. HomeServices expanded its mortgage business in 2014 through the acquisition of the remaining 50.1% interest in HomeServices Lending, LLC ("HomeServices Lending").

Refer to Note 22 of Notes to Consolidated Financial Statements 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, the Company changed its name 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. 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 sells electricity to other utilities, energy marketing companies, financial institutions and other market participants on a wholesale basis.

PacifiCorp's operations are conducted under numerous franchise agreements, certificates, permits and licenses obtained from federal, state and local authorities. The average term of the franchise agreements is approximately 28 years, although their terms range from five years to indefinite. Several of these franchise agreements allow the municipality the right to seek amendment to the franchise agreement at a specified time during the term. PacifiCorp generally has an exclusive right to serve electric customers within its service territories and, in turn, has an obligation to provide electric service to those customers. 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 investment.

Regulated Electric Operations

Customers

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

	2014		**2013**		**2012**	
Utah	24,105	44%	24,510	44%	23,930	44%
Oregon	12,959	24	13,090	24	12,779	23
Wyoming	9,568	17	9,554	17	9,498	17
Washington	4,118	8	4,093	7	4,042	7
Idaho	3,495	6	3,621	7	3,518	7
California	754	1	795	1	782	2
	54,999	100%	55,663	100%	54,549	100%

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

	2014		2013		2012	
GWh sold:						
Residential	15,568	24%	16,339	25%	15,968	24%
Commercial	17,073	26	17,057	26	16,829	25
Industrial and irrigation	21,934	34	21,832	33	21,317	32
Other	424	—	435	1	435	1
Total retail	54,999	84	55,663	85	54,549	82
Wholesale	10,270	16	10,206	15	11,870	18
Total GWh sold	65,269	100%	65,869	100%	66,419	100%
Average number of retail customers (in thousands):						
Residential	1,546	87%	1,522	86%	1,504	86%
Commercial	200	11	208	12	212	12
Industrial and irrigation	33	2	34	2	34	2
Other	4	—	3	—	4	—
Total	1,783	100%	1,767	100%	1,754	100%

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

The annual hourly peak customer demand, which represents the highest demand on a given day and at a given hour, is typically highest in the summer across PacifiCorp's service territory when air conditioning and irrigation systems are heavily used. The service territory also has a winter peak, which is primarily due to heating requirements in the western portion of PacifiCorp's service territory. During 2014, PacifiCorp's peak demand was 10,314 MW in the summer and 8,870 MW in the winter.

Generating Facilities and Fuel Supply

PacifiCorp has ownership interest in a diverse portfolio of generating facilities. The following table presents certain information regarding PacifiCorp's owned generating facilities as of December 31, 2014:

Generating Facility	Location	Energy Source	Installed	Facility Net Capacity (MW)(1)	Net Owned Capacity (MW)(1)
COAL:					
Jim Bridger Nos. 1, 2, 3 and 4	Rock Springs, WY	Coal	1974-1979	2,123	1,415
Hunter Nos. 1, 2 and 3	Castle Dale, UT	Coal	1978-1983	1,363	1,158
Huntington Nos. 1 and 2	Huntington, UT	Coal	1974-1977	909	909
Dave Johnston Nos. 1, 2, 3 and 4	Glenrock, WY	Coal	1959-1972	760	760
Naughton Nos. 1, 2 and 3(2)	Kemmerer, WY	Coal	1963-1971	687	687
Cholla No. 4	Joseph City, AZ	Coal	1981	395	395
Wyodak No. 1	Gillette, WY	Coal	1978	332	266
Carbon Nos. 1 and 2(3)	Castle Gate, UT	Coal	1954-1957	172	172
Craig Nos. 1 and 2	Craig, CO	Coal	1979-1980	855	165
Colstrip Nos. 3 and 4	Colstrip, MT	Coal	1984-1986	1,480	148
Hayden Nos. 1 and 2	Hayden, CO	Coal	1965-1976	446	78
				9,522	6,153
NATURAL GAS:					
Lake Side 2	Vineyard, UT	Natural gas/steam	2014	631	631
Lake Side	Vineyard, UT	Natural gas/steam	2007	546	546
Currant Creek	Mona, UT	Natural gas/steam	2005-2006	524	524
Chehalis	Chehalis, WA	Natural gas/steam	2003	477	477
Hermiston	Hermiston, OR	Natural gas/steam	1996	461	231
Gadsby Steam	Salt Lake City, UT	Natural gas	1951-1955	238	238
Gadsby Peakers	Salt Lake City, UT	Natural gas	2002	119	119
				2,996	2,766
HYDROELECTRIC:					
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	36	36
				1,145	1,145
WIND:					
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:					
Blundell	Milford, UT	Geothermal	1984, 2007	32	32
Camas Co-Gen	Camas, WA	Black liquor	1996	10	10
				42	42
Total Available Generating Capacity				14,744	11,136

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

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

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

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

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

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

PacifiCorp is required to have resources available to continuously meet its customer needs. The percentage of PacifiCorp's energy supplied by energy source varies from year to year and is subject to numerous operational and economic factors such as planned and unplanned outages, fuel commodity prices, fuel transportation costs, weather, environmental considerations, transmission constraints, and wholesale market prices of electricity. PacifiCorp evaluates these factors continuously in order to facilitate economical dispatch of its generating facilities. When factors for one energy source are less favorable, PacifiCorp must place more reliance on other energy sources. For example, PacifiCorp can generate more electricity using its low cost hydroelectric and wind-powered generating facilities when factors associated with these facilities are favorable. When factors associated with hydroelectric and wind resources are less favorable, PacifiCorp increases its reliance on coal- and natural gas-fueled generation or purchased electricity. In addition to meeting its customers' energy needs, PacifiCorp is required to maintain operating reserves on its system to mitigate the impacts of unplanned outages or other disruption in supply, and to meet intra-hour changes in load and resource balance. This operating reserve requirement is dispersed across PacifiCorp's generation portfolio on a least-cost basis based on the operating characteristics of the portfolio. Operating reserves may be held on hydroelectric, coal-fueled or natural gas-fueled resources. PacifiCorp manages certain risks relating to its supply of electricity and fuel requirements by entering into various contracts, which may be accounted for as derivatives and may include forwards, options, swaps and other agreements. Refer to "General Regulation" in Item 1 of this Form 10-K for a discussion of energy cost recovery by jurisdiction and to Item 7A in this Form 10-K for a discussion of commodity price risk and derivative contracts.

PacifiCorp has interests in coal mines that support its coal-fueled generating facilities and operates the Bridger surface and Bridger underground coal mines, as well as the Deer Creek underground coal mine discussed below that has historically served the Huntington, Hunter and Carbon generating facilities. These mines supplied 27%, 31% and 30% of PacifiCorp's total coal requirements during the years ended December 31, 2014, 2013 and 2012, respectively. The remaining coal requirements are acquired through long- and short-term third-party contracts. PacifiCorp also operates the Cottonwood Preparatory Plant and Wyodak Coal Crushing Facility.

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

Most of PacifiCorp's coal reserves are held pursuant to leases through the federal Bureau of Land Management and from certain states and private parties. The leases generally have multi-year terms that may be renewed or extended only with the consent of the lessor and require payment of rents and royalties. In addition, federal and state regulations require that comprehensive environmental protection and reclamation standards be met during the course of mining operations and upon completion of mining activities.

Coal reserve estimates are subject to adjustment as a result of the development of additional engineering and geological data, new mining technology and changes in regulation and economic factors affecting the utilization of such reserves. Recoverable coal reserves of operating mines as of December 31, 2014, based on recent engineering studies, were as follows (in millions):

Coal Mine	Location	Generating Facility Served	Mining Method	Recoverable Tons	
Bridger	Rock Springs, WY	Jim Bridger	Surface	35	(1)
Bridger	Rock Springs, WY	Jim Bridger	Underground	35	(1)
Trapper	Craig, CO	Craig	Surface	6	(2)
				76	

(1) These coal reserves are leased and mined by Bridger Coal Company, a joint venture between Pacific Minerals, Inc. and a subsidiary of Idaho Power Company. Pacific Minerals, Inc., a wholly owned subsidiary of PacifiCorp, has a two-thirds interest in the joint venture. The amounts included above represent only PacifiCorp's two-thirds interest in the coal reserves.

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

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

For underground mine operations, a longwall is used as a mechanical shearer to extract coal from long rectangular blocks of medium to thick seams that are initially developed by the use of continuous miner machines. In longwall mining, hydraulically powered supports temporarily hold up the roof of the mine while a rotating drum mechanically advances across the face of the coal seam, cutting the coal from the face. Chain conveyors then move the loosened coal to an underground mine conveyor system for delivery to the surface. Once coal is extracted from an area, the roof is allowed to collapse in a controlled fashion.

In June 2011, Fossil Rock Fuels, LLC ("Fossil Rock"), a wholly owned subsidiary of PacifiCorp, acquired the Cottonwood coal reserve lease in Emery County Utah, which contains an estimated 47 million tons of recoverable coal. Subject to the regulatory approvals described in "Regulatory Matters" in Item 7 of this Form 10-K, PacifiCorp intends to sell the rights to the Fossil Rock coal reserves to a third party in the second quarter of 2015.

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

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 operates the majority of its hydroelectric generating portfolio under long-term licenses. The FERC regulates 98% of the net capacity of this portfolio through 15 individual licenses, which have terms of 30 to 50 years. A portion of this portfolio is licensed under the Oregon Hydroelectric Act. For further discussion of PacifiCorp's hydroelectric relicensing activities, including updated information regarding the Klamath River hydroelectric system, refer to Note 16 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

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.

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 16,400 miles of transmission lines, 63,000 miles of distribution lines and 900 substations as of December 31, 2014.

PacifiCorp's Energy Gateway Transmission Expansion Program represents plans to build approximately 2,000 miles of new high-voltage transmission lines, with an estimated cost exceeding $6 billion, primarily in Wyoming, Utah, Idaho and Oregon. The $6 billion estimated cost includes: (a) the 345-kV Populus to Terminal transmission line placed in-service in 2010; (b) the 100-mile high-voltage transmission line between the Mona substation in central Utah and the Oquirrh substation in the Salt Lake Valley placed in-service in 2013; (c) the 345-kV transmission line being built between the Sigurd Substation in central Utah and the Red Butte Substation in southwest Utah expected to be placed in-service in May 2015; and (d) other segments that are expected to be placed in-service in future years, depending on load growth, siting, permitting and construction schedules. The transmission line segments are intended to: (a) address customer load growth; (b) improve system reliability; (c) reduce transmission system constraints; (d) provide access to diverse generation resources, including renewable resources; and (e) improve the flow of electricity throughout PacifiCorp's six-state service area. Proposed transmission line segments are re-evaluated to ensure optimal benefits and timing before committing to move forward with permitting and construction. Through December 31, 2014, $1.8 billion had been spent and $1.3 billion, including AFUDC, had been placed in-service.

Energy Imbalance Market

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

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

Future Generation

As required by certain state regulations, PacifiCorp uses an Integrated Resource Plan ("IRP") to develop a long-term view of prudent future actions required to help ensure that PacifiCorp continues to provide reliable and cost-effective electric service to its customers while maintaining compliance with existing and evolving environmental laws and regulations. The IRP process identifies the amount and timing of PacifiCorp's expected future resource needs and an associated optimal future resource mix that accounts for planning uncertainty, risks, reliability impacts, state energy policies and other factors. The IRP is a coordinated effort with stakeholders in each of the six states where PacifiCorp operates. PacifiCorp files its IRP on a biennial basis and five states indicate whether the IRP meets the state commission's IRP standards and guidelines, a process referred to as "acknowledgment" in some states. In April 2013, PacifiCorp filed its 2013 IRP with the state commissions. The WPSC accepted the 2013 IRP into its files and the IPUC, the WUTC and the UPSC acknowledged the 2013 IRP. The OPUC acknowledged the 2013 IRP with exceptions and revisions to specific action items. PacifiCorp is currently developing its 2015 IRP that is expected to be filed in March 2015.

Demand-side Management

PacifiCorp has provided a comprehensive set of DSM programs to its customers since the 1970s. The programs are designed to reduce energy consumption and more effectively manage when energy is used, including management of seasonal peak loads. PacifiCorp offers services to customers such as energy engineering audits and information on how to improve the efficiency of their homes and businesses. To assist customers in investing in energy efficiency, PacifiCorp offers rebates or incentives encouraging the purchase and installation of high-efficiency equipment such as lighting, heating and cooling equipment, weatherization, motors, process equipment and systems, as well as incentives for efficient construction. Incentives are also paid to solicit participation in load management programs by residential, business and agricultural customers through programs such as PacifiCorp's residential and small commercial air conditioner load control program and irrigation equipment load control programs. Although subject to prudence reviews, state regulations allow for contemporaneous recovery of costs incurred for the DSM programs through state-specific energy efficiency surcharges to retail customers or for recovery of costs through rates. During 2014, PacifiCorp spent $155 million on these DSM programs, resulting in an estimated 566,034 MWh of first-year energy savings and an estimated 312 MW of peak load management. In addition to these DSM programs, PacifiCorp has load curtailment contracts with a number of large industrial customers that deliver up to 305 MW of load reduction when needed, depending on the customers' actual loads. Recovery of the costs associated with the large industrial load management program is determined through PacifiCorp's rate case process.

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 0.7 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 and includes 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 has nonregulated business activities that consist of competitive electricity and natural gas retail sales and natural gas income-sharing arrangements. Nonregulated electric activities predominantly include sales to retail customers in Illinois, Texas, Ohio, Maryland and other states that allow customers to choose their energy supplier. Nonregulated natural gas activities predominately include sales to retail customers in Iowa and Illinois. For its nonregulated retail energy activities, MidAmerican Energy purchases electricity and natural gas from producers and third party energy marketing companies and sells it directly to commercial, industrial and governmental end-users. MidAmerican Energy does not own nonregulated electricity or natural gas production assets, but hedges its contracted sales obligations either with physical supply arrangements or financial products. As of December 31, 2014, MidAmerican Energy had contracts in place for the sale of electricity totaling 17,460,000 MWh with a weighted average life of 2.1 years and natural gas totaling 24,411,000 Dth with a weighted average life of 1.5 years. In addition, MidAmerican Energy manages 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.

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:

	2014	2013	2012
Operating revenue:			
Regulated electric	48%	52%	52%
Regulated gas	27	24	20
Nonregulated and other	25	24	28
	100%	100%	100%
Net income:			
Regulated electric	86%	84%	84%
Regulated gas	10	12	8
Nonregulated and other	4	4	8
	100%	100%	100%

Regulated Electric Operations

<u>Customers</u>

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

	2014		2013		2012	
Iowa	20,585	90%	20,217	90%	19,678	90%
Illinois	1,975	9	2,015	9	2,038	9
South Dakota	217	1	220	1	208	1
	22,777	100%	22,452	100%	21,924	100%

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

	2014		2013		2012	
GWh sold:						
Residential	6,429	20%	6,572	20%	6,345	19%
Commercial	4,084	12	4,265	13	4,175	13
Industrial	10,642	33	10,001	31	9,805	30
Other	1,622	5	1,614	5	1,599	5
Total retail	22,777	70	22,452	69	21,924	67
Wholesale	9,716	30	10,226	31	10,961	33
Total GWh sold	32,493	100%	32,678	100%	32,885	100%
Average number of retail customers (in thousands):						
Residential	643	86%	637	86%	633	86%
Commercial	87	12	86	12	85	12
Industrial	2	—	2	—	2	—
Other	14	2	14	2	14	2
Total	746	100%	739	100%	734	100%

In addition to the variations in weather from year to year, fluctuations in economic conditions within the 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 the use of electricity for air conditioning and the related effects of weather. 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 21, 2014, retail customer usage of electricity caused an hourly peak demand of 4,366 MW on MidAmerican Energy's electric distribution system, which is 386 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, 2014:

Generating Facility	Location	Energy Source	Installed	Facility Net Capacity (MW)(1)	Net Owned Capacity (MW)(1)
COAL:					
Walter Scott, Jr. Nos. 1, 2, 3 and 4(2)	Council Bluffs, IA	Coal	1954-2007	1,648	1,172
George Neal Nos. 1, 2 and 3(2)	Sergeant Bluff, IA	Coal	1964-1975	902	760
Louisa	Muscatine, IA	Coal	1983	742	653
Ottumwa	Ottumwa, IA	Coal	1981	718	373
George Neal No. 4	Salix, IA	Coal	1979	644	262
Riverside No. 5(3)	Bettendorf, IA	Coal	1961	124	124
				4,778	3,344
NATURAL GAS:					
Greater Des Moines	Pleasant Hill, IA	Natural gas	2003-2004	485	485
Electrifarm	Waterloo, IA	Natural gas/oil	1975-1978	188	188
Pleasant Hill	Pleasant Hill, IA	Natural gas/oil	1990-1994	161	161
Sycamore	Johnston, IA	Natural gas/oil	1974	148	148
River Hills	Des Moines, IA	Natural gas	1966-1967	122	122
Coralville	Coralville, IA	Natural gas	1970	65	65
Moline	Moline, IL	Natural gas	1970	64	64
Parr	Charles City, IA	Natural gas	1969	17	17
28 portable power modules	Various	Oil	2000	56	56
				1,306	1,306
WIND:					
Rolling Hills	Massena, IA	Wind	2011	443	443
Pomeroy	Pomeroy, IA	Wind	2007-2011	286	286
Lundgren	Otho, IA	Wind	2014	250	250
Century	Blairsburg, IA	Wind	2005-2008	200	200
Eclipse	Adair, IA	Wind	2012	200	200
Intrepid	Schaller, IA	Wind	2004-2005	176	176
Adair	Adair, IA	Wind	2008	175	175
Walnut	Walnut, IA	Wind	2008	150	150
Carroll	Carroll, IA	Wind	2008	150	150
Vienna	Marshalltown, IA	Wind	2012-2013	150	150
Wellsburg	Wellsburg, IA	Wind	2014	139	139
Laurel	Laurel, IA	Wind	2011	120	120
Macksburg	Macksburg, IA	Wind	2014	119	119
Morning Light	Adair, IA	Wind	2012	100	100
Victory	Westside, IA	Wind	2006	99	99
Charles City	Charles City, IA	Wind	2008	75	75
				2,832	2,832
NUCLEAR:					
Quad Cities Nos. 1 and 2	Cordova, IL	Uranium	1972	1,816	454
OTHER:					
Moline Nos. 1-4	Moline, IL	Hydroelectric	1941	2	2
Total Available Generating Capacity				10,734	7,938
PROJECTS UNDER CONSTRUCTION:					
Various wind projects				625	625
				11,359	8,563

(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 Walter Scott Jr. Unit Nos. 1 and 2 (124 MWs owned) by April 15, 2015, and George Neal Unit Nos. 1 and 2 (394 MWs owned) by April 15, 2016. Refer to "Environmental Laws and Regulations" in Item 7 of this Form 10-K for further discussion.

(3) MidAmerican Energy currently plans to limit Riverside Unit No. 5 to natural gas combustion by March 31, 2015. Refer to "Environmental Laws and Regulations" in Item 7 of this Form 10-K for further discussion.

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

	2014	2013	2012
Coal	55%	55%	58%
Nuclear	12	12	11
Natural gas	—	1	2
Wind and other[1]	24	22	19
Total energy generated	91	90	90
Energy purchased - short-term contracts and other	7	9	8
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 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 2018. MidAmerican Energy believes supply 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 2015 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 for short-haul delivery to the Louisa and Riverside 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 ("Exelon Generation"), the 75% joint owner and the operator of Quad Cities Station, is a subsidiary of Exelon Corporation. 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 2018 and partial requirements through 2020; uranium conversion requirements through 2020 and partial requirements through 2021; enrichment requirements through 2017 and partial requirements through 2028; 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, 2014 are authorized to earn a fixed rate of return on equity over their useful lives ranging from 11.625% to 12.2% in any future Iowa rate proceeding. Renewable resources have low to no emissions and require little or no fossil fuel. 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 2024.

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.

Transmission and Distribution

MidAmerican Energy's transmission and distribution systems included 3,800 miles of transmission lines, 37,800 miles of distribution lines and 380 substations as of December 31, 2014. 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. Costs of the 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 2014, 48% of the total natural gas delivered through MidAmerican Energy's distribution system was associated with transportation service.

Customers

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

	2014	2013	2012
Iowa	77%	76%	76%
South Dakota	12	13	13
Illinois	10	10	10
Nebraska	1	1	1
	100%	100%	100%

The percentages of natural gas sold to 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:

	2014	2013	2012
Residential	49%	46%	41%
Commercial(1)	24	24	21
Industrial(1)	5	4	5
Total retail	78	74	67
Wholesale(2)	22	26	33
	100%	100%	100%
Total Dth of natural gas sold (in thousands)	115,209	115,857	99,453
Total Dth of transportation service (in thousands)	82,314	78,208	73,675
Total average number of retail customers (in thousands)	726	719	714

(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 1,281,762 Dth. This peak-day delivery consisted of 69% traditional retail sales service and 31% transportation service. MidAmerican Energy's 2014/2015 winter heating season peak-day delivery as of February 6, 2015, was 1,128,779 Dth reached on January 7, 2015. This preliminary peak-day delivery included 70% traditional retail sales service and 30% 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.

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 approximately 50% of MidAmerican Energy's anticipated retail sales requirements on a peak winter day.

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, 2014.

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 in more recent years. 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 2014, $106 million was expended on MidAmerican Energy's DSM programs resulting in estimated first-year energy savings of 261,000 MWh of electricity and 653,000 Dth of natural gas and an estimated peak load reduction of 319 MW of electricity and 7,345 Dth per day of natural gas.

NV Energy

General

NV Energy, an indirect wholly owned subsidiary of BHE acquired on December 19, 2013 ("NV Energy Transaction"), 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 and Sierra Pacific is a United States regulated electric and natural gas utility company. The Nevada Utilities serve 1.2 million regulated retail electric customers in Nevada, primarily in Las Vegas and Reno/Sparks, and 0.2 million regulated retail and transportation natural gas customers in northern Nevada, primarily in Reno/Sparks. 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. 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 Sierra Pacific included 3,200 miles of natural gas mains and service lines as of December 31, 2014. The Nevada Utilities' combined service territory covers approximately 46,000 square miles. Principal industries served by the Nevada Utilities include gaming, mining, recreation, warehousing, manufacturing and government. In addition to retail sales and natural gas transportation, the Nevada Utilities sell electricity and natural gas to other utilities, municipalities and energy marketing companies on a wholesale basis.

The Nevada Utilities' regulated 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 2015 through 2032. In addition, 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 their costs of providing services and to earn a reasonable return on their investment.

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

	2014	2013	2012
Regulated electric	96%	96%	96%
Regulated gas	4	4	4
	100%	100%	100%

Regulated Electric Operations

Customers

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

	2014		2013		2012	
GWh sold:						
Residential	11,191	37%	11,382	38%	11,382	37%
Commercial	7,433	25	7,374	24	7,430	24
Industrial	10,355	35	10,351	34	10,373	34
Other	227	1	228	1	234	1
Total retail	29,206	98	29,335	97	29,419	96
Wholesale	665	2	911	3	1,069	4
Total GWh sold	29,871	100%	30,246	100%	30,488	100%
Average number of retail customers (in thousands):						
Residential	1,055	88%	1,036	87%	1,026	87%
Commercial	148	12	149	13	146	13
Industrial	2	—	2	—	2	—
Total	1,205	100	1,187	100	1,174	100

In addition to the variations in weather from year to year, fluctuations in economic conditions within the 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 the use of electricity for air conditioning and the related effects of weather. Typically, 35-50% of the Nevada Utilities' 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 July 1, 2014, retail customer usage of electricity caused an hourly peak demand of 5,572 MW on Nevada Power's electric distribution system, which is 282 MW less than the record hourly peak demand of 5,854 MW set July 2, 2013. On July 14, 2014, Sierra Pacific's retail customer usage of electricity caused a record hourly peak demand of 1,761 MW on Sierra Pacific's electric distribution system.

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, 2014:

Generating Facility	Location	Energy Source	Installed	Facility Net Capacity (MW)(1)	Net Owned Capacity (MW)(1)
COAL:					
Valmy Unit Nos. 1 and 2	Valmy, NV	Coal	1981-1985	522	261
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
				3,029	773
NATURAL GAS:					
Clark	Las Vegas, NV	Natural Gas	1973-2008	1,103	1,103
Lenzie	Las Vegas, NV	Natural gas	2006	1,102	1,102
Tracy	Sparks, NV	Natural gas/oil	1974-2008	753	753
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
Ft. Churchill	Yerrington, NV	Natural gas/oil	1968-1971	226	226
Sun Peak	Las Vegas, NV	Natural gas	1991	210	210
Clark Mountain	Sparks, NV	Natural gas	1994	132	132
				5,476	5,346
OTHER:					
Goodsprings	Goodsprings, NV	Waste heat	2010	5	5
Total Available Generating Capacity				8,510	6,124
PROJECTS UNDER CONSTRUCTION:					
Nellis	Las Vegas, NV	Solar		15	15
				8,525	6,139

(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 the Nevada Utilities' ownership of Facility Net Capacity.

(2) The Company currently anticipates retiring Reid Gardner Unit No. 4 in December 2017 and Navajo Unit Nos. 1, 2 and 3 in 2019. Reid Gardner Unit Nos. 1, 2 and 3 were retired in December 2014. Refer to "Environmental Laws and Regulations" in Item 7 of this Form 10-K for further discussion.

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

	2014	2013	2012
Natural gas	53%	58%	59%
Coal	20	14	10
Total energy generated	73	72	69
Energy purchased - short-term contracts and other	1	3	6
Energy purchased - long-term contracts (renewable)(1)	10	10	13
Energy purchased - long-term contracts (non-renewable)	16	15	12
	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, (b) sold to third parties in the form of RECs or other environmental commodities, or (c) excluded from energy purchased.

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 base tariff rates based on the last twelve months fuel costs and purchased power and to reset quarterly deferred energy annual adjustments.

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. 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 natural gas and renewable resources with a total nameplate capacity of 2,459 MW and contract termination dates ranging from 2016 to 2040. Included in these contracts are 1,049 MW of nameplate capacity of renewable energy, of which 178 MW of nameplate capacity are under development or construction and not currently available.

To secure natural gas supplies for the generating facilities the Nevada Utilities either own, have under long-term contract (tolling arrangements) or for Sierra Pacific's regulated natural gas operations, the Nevada Utilities contract for firm winter, summer, and annual natural gas supplies with numerous domestic and Canadian suppliers. In 2014, natural gas supply net purchases averaged 396,587 Dth per day, with the winter period contracts averaging 371,705 Dth per day and the summer period contracts averaging 422,001 Dth per day. The Nevada Utilities believe supplies from these sources are presently adequate and available to meet their 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 Kern River, an affiliated company. The Nevada Utilities utilize 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 storage gas is typically replaced during off-peak months when the demand for natural gas is historically lower than during the heating season.

Nevada Power has no coal commitments for Reid Gardner Unit No. 4 for 2015 or beyond and will rely on spot market solicitations for any coal supplies needed during 2015. The coal supply plan has the overall goal of eliminating its coal pile by the end of 2017. The rail transportation service contract between Nevada Power and Union Pacific Railroad Company expired December 31, 2014. This contract contained a volume shortfall provision in which the Company incurred and accrued. The Navajo Generating Station, jointly owned by Nevada Power along with five other entities and operated by Salt River Project, has a coal sales agreement that extends through 2019. Sierra Pacific has a long-term coal contract for the Valmy Generating Station that expires December 31, 2015. The Nevada Utilities manage their coal supplies based on anticipated needs and through various arrangements, including spot purchases and long- and short-term contracts. The Nevada Utilities regularly monitor the western coal market for opportunities to enhance their coal supply portfolios.

Transmission and Distribution

The Nevada Utilities' transmission system is part of the Western Interconnection, which includes the interconnected transmission systems of 14 western states, two Canadian provinces and parts of Mexico. The 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. The Nevada Utilities' transmission and distribution systems included approximately 4,100 miles of transmission lines, 41,300 miles of distribution lines and 400 substations as of December 31, 2014.

On December 31, 2013, the Nevada Utilities completed construction and placed in-service a 231 mile, 500-kV transmission line connecting the Nevada Utilities' northern and southern service territories ("ON Line"). ON Line has enabled the Nevada Utilities to optimize their generation assets by enhancing their transmission capabilities. 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 will enhance the Nevada Utilities ability to manage and optimize their generating facilities. ON Line provides between 600 and 800 MW of transfer capability between northern and southern Nevada. ON Line was a joint project between the Nevada Utilities and Great Basin Transmission, LLC. With the completion of ON Line, the parties completed construction of a 500-kV interconnection between the Robinson Summit substation on the Sierra Pacific system and the Harry Allen substation on the Nevada Power system. 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.

Energy Imbalance Market

The Nevada Utilities have announced plans to join the EIM in October 2015. The EIM 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. In today's environment, utilities in the Western United States outside the EIM footprint rely upon a combination of automated and manual dispatch within the hour to balance generation and load to maintain reliable supply and have limited capability to transact within the hour outside their own borders. In contrast, 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. 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 transmission grid network, meteorological and load forecast information that it uses to optimize dispatch instructions. The EIM is voluntary and available to all balancing authorities in the Western United States. 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. In April 2014, the Nevada Utilities filed an application to amend their portfolio optimization procedures contained in the PUCN-approved energy supply plan to include EIM starting October 2015. The amendment reflects the Nevada Utilities' participation in the EIM that is being established by the California ISO. The filing requested the PUCN to determine that the amended energy supply plan balances the objectives of minimizing the cost of supply and retail price volatility, maximizes the reliability of supply over the remaining term of the plan, optimizes the value of the overall supply portfolio of the Nevada Utilities for the benefit of bundled retail customers and does not contain any features or mechanisms that the PUCN finds would impair the restoration or the creditworthiness of the Nevada Utilities. 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. In April 2014, the California ISO filed the Implementation Agreement entered into by the Nevada Utilities and the California ISO. The Implementation Agreement provides the mechanism by which the Nevada Utilities will compensate the California ISO for their share of the costs to upgrade systems, software licenses and other configuration activities. The Implementation Agreement was approved by the FERC in June 2014.

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. Nevada Power and Sierra Pacific are scheduled to file a triennial IRP before July 1, 2015 and 2016, respectively.

Demand-side Management

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 engineering audits and information on how to improve the efficiency of their homes and businesses. To assist customers in investing in energy efficiency, the Nevada Utilities offer 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 2014, the Nevada Utilities spent $47 million on their energy efficiency programs, resulting in an estimated 194,999 MWh of electric energy savings and an estimated 40 MW of electric peak load management.

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 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 and to generators that are connected to their networks.

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 25% of the total combined distribution revenue of the Northern Powergrid Distribution Companies during 2014. 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 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 (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, 2010 and is expected to continue through March 31, 2015. Ofgem has set the next price control for the eight-year period from April 1, 2015 to March 31, 2023. The Northern Powergrid Distribution Companies resubmitted their business plans for the next price control period to Ofgem in March 2014, following feedback from Ofgem on their initial submission in July 2013, with final determinations published in November 2014. The remaining necessary step for this price control to be effective is the statutory modification of the license, which was published by Ofgem on February 3, 2015 and will be final on March 3, 2015.

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

	2014		2013		2012	
Northern Powergrid (Northeast) Limited:						
Residential	5,161	34%	5,379	35%	5,525	36%
Commercial	2,393	16%	2,485	16	2,513	16
Industrial	7,181	48%	7,166	47	7,058	46
Other	262	2%	269	2	295	2
	14,997	100%	15,299	100%	15,391	100%
Northern Powergrid (Yorkshire) plc:						
Residential	7,481	35%	7,812	35%	8,054	36%
Commercial	3,347	16	3,501	16	3,525	16
Industrial	10,486	48	10,793	48	10,755	47
Other	322	1	313	1	311	1
	21,636	100%	22,419	100%	22,645	100%
Total electricity distributed	36,633		37,718		38,036	
Number of end-users (in thousands):						
Northern Powergrid (Northeast) Limited	1,593		1,588		1,585	
Northern Powergrid (Yorkshire) plc	2,286		2,279		2,274	
	3,879		3,867		3,859	

As of December 31, 2014, 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 market-based rates for certain of its firm storage contracts with contract terms that expire in 2028.

Operating revenue for the years ended December 31 was as follows (in millions):

	2014		2013		2012	
Transportation:						
Market Area	$ 457	63%	$ 444	75%	$ 438	75%
Field Area	100	14	64	11	60	10
Total transportation	557	77	508	86	498	85
Storage	61	8	58	10	67	11
Total transportation and storage revenue	618	85	566	96	565	96
Gas, liquids and other sales	106	15	27	4	20	4
Total operating revenue	$ 724	100%	$ 593	100%	$ 585	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, 2014, over 56% of Northern Natural Gas' customers' entitlement in the Market Area have terms beyond 2017. As of December 31, 2014, the weighted average remaining contract term for Northern Natural Gas' Market Area firm transportation contracts is approximately five years.

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 2018, 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 1.7 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 to meet 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 five 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 thirteen 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 2014, 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 63% of its system-wide transportation and storage revenue. Northern Natural Gas has agreements to retain the vast majority of its three largest customers' volumes through at least 2017. The loss of any of these significant customers, if not replaced, could have a material adverse effect on Northern Natural Gas.

Northern Natural Gas is developing a new rate recovery mechanism to track and recover one-time capital expenditures made to modernize its Market Area pipeline system. The capital expenditures, up to $450 million, will retire and replace aging facilities to allow Northern Natural Gas to continue to ensure the reliable, safe and efficient operation of its pipeline system. The capital expenditures are expected to be incurred between 2016 and 2024 with rate recovery to begin the year following the calendar year in which the applicable facility was placed in-service. The rate structure of any such recovery mechanism requires shipper support and approval by the FERC.

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 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 23% of California's demand for natural gas in 2013. 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.

98% 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 February 2016 and April 2033 and have a weighted-average remaining contract term of nearly five 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, 2014, nearly 84% 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 2014, 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. As of February 1, 2015, Kern River has sold 189,533 Dth per day of the total turned back volume of 231,878 Dth per day with terms of one year or greater. 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 winter of 2013-2014. Northern Natural Gas' customers' ability to access multiple supply basins has been critical to customers managing their 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 ("AltaLink Transaction"), 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 132,000 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 7,800 miles of transmission lines and 300 substations as of December 31, 2014, 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 13,000 miles of transmission and over 400 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 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 investment. 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.

The AESO filed its 2013 Long-Term Transmission System Plan in January 2014 and released the Regional Development Plans in April 2014. There are 37 projects proposed out to 2017 included in the plans requiring investment of C$11.6 billion. The C $11.6 billion includes C$7.5 billion representing committed project dollars already approved by the AUC and C$4.1 billion representing planning stage projects that have not received regulatory approval.

ALP is working with the AESO to develop the need and facility applications required to support the new projects identified in the AESO's system plan. ALP executes its capital projects program using an outsourced Engineering, Procurement and Construction Management model. This strategic outsourcing arrangement enhances ALP's capability to deliver results to customers by facilitating design and construction of its capital projects in a timely and cost-effective manner.

In its general tariff application for 2015 and 2016, ALP forecasted C$1.5 billion and C$1.1 billion, respectively, gross direct assigned capital expenditures based on the most recent 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. 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.

The Company 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, 2014, had total assets of $2.4 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. ETT has completed a total of $1.5 billion of Competitive Renewable Energy Zone ("CREZ") projects and has constructed or is constructing an additional $1.6 billion of transmission projects within ERCOT. A total of $2.2 billion was in-service as of December 31, 2014, with the remaining projects forecast to be completed between 2015 and 2024. ETT's transmission system includes approximately 1,000 line miles of transmission and 30 substations as of December 31, 2014.

The Company 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. Construction began in 2012 and the necessary approvals from the FERC have been received, including a return on equity, inclusive of incentives, of 12.8% and a debt to equity capital structure of 50:50. The project is expected to cost $162 million and was fully placed in-service in November 2014.

BHE Renewables

The subsidiaries comprising the BHE Renewables reportable segment own interests in 23 independent power projects that are in-service or under construction in the United States and one independent power project in the Philippines. The solar and wind-powered projects were all acquired in 2012, with the exception of Jumbo Road which was acquired in 2014. Additionally, in June 2014 and November 2014, BHE Renewables acquired the remaining 50% interest in CE Generation and Wailuku Investment, LLC, respectively.

The following table presents certain information concerning these independent power projects as of December 31, 2014:

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 I	California	Solar	2013-2014	2035	SCE	172	172
Solar Star II	California	Solar	2013-2014	2035	SCE	228	228
Agua Caliente	Arizona	Solar	2012-2013	2039	PG&E	290	142
						1,240	1,092
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
						381	381
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	2015	TEMUS	245	184
Power Resources	Texas	Natural Gas	1988	2015	EDF	212	212
Yuma	Arizona	Natural Gas	1994	2024	SDG&E	50	50
Cordova	Illinois	Natural Gas	2001	2019	EGC	512	512
						1,019	958
Total Available Generating Capacity						3,138	2,907
PROJECTS UNDER CONSTRUCTION:							
Jumbo Road	Texas	Wind	2015	2033	AE	300	300
Solar Star I	California	Solar	2015	2035	SCE	137	137
Solar Star II	California	Solar	2015	2035	SCE	42	42
						479	479
						3,617	3,386

(1) TransAlta Energy Marketing U.S. ("TEMUS"); EDF Trading North America 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"); and Austin Energy ("AE").

(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 Company's interests in the Imperial Valley Projects' Contract Capacity are 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, the Company 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 the Company 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):

	2014	2013	2012
Solar	$ 238	$ 73	$ —
Wind	99	121	9
Geothermal	125	—	—
Hydro	107	129	125
Natural gas	54	32	32
Total operating revenue	$ 623	$ 355	$ 166

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 460 offices in 25 states with over 24,000 sales associates under 30 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. HomeServices Lending originated $373 million of mortgage loans from October 1, 2014 through December 31, 2014.

In October 2012, HomeServices acquired a 66.7% interest in the second-largest residential real estate brokerage franchise network 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 440 franchisees in over 1,500 brokerage offices in 49 states with over 43,000 sales associates under three brand names. In exchange for certain fees, HomeServices provides the right to use the Berkshire Hathaway HomeServices, Prudential and 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, 2014, over 170 franchisees of the original 330 identified Prudential brokers, representing 74% of the 2012 revenue, had been rebranded.

Other Investments

Natural Gas Storage Joint Venture

In January 2011, the Regulatory Commission of Alaska authorized Cook Inlet Natural Gas Storage Alaska, LLC ("CINGSA"), a wholly-owned subsidiary of Alaska Storage Holdings Company, LLC ("ASHC"), to own, construct and operate an underground natural gas storage facility in south central Alaska. BHE, through an indirect wholly-owned subsidiary, has a 26.5% interest in ASHC. CINGSA's gas storage facility includes a natural gas reservoir, five injection/withdrawal wells and associated piping allowing for an initial working gas capacity of 11 Bcf and the ability to deliver gas up to 0.15 Bcf per day. The facility was placed in-service in the second quarter of 2012. CINGSA has contracted to provide firm service to four customers for 20 years.

Employees

As of December 31, 2014, the Company had approximately 20,900 employees, of which approximately 8,700 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 September 2018. HomeServices' approximately 24,000 sales associates are independent contractors and not employees.

General Regulation

BHE's subsidiaries 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 following discussion, refer to "Regulatory Matters" in Item 7 of this Form 10-K.

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 the Company'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. As of December 31, 2014, there were 17 large customers securing their own supplies. These customers have a combined firm distribution load of approximately 4,800 Dth per day, continue to pay firm and interruptible distribution charges and are responsible for procuring and paying for their own natural gas supply, which reduces Sierra Pacific's purchases, but does not impact net income.

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. Balancing account to provide for the recovery or refund of the difference between the level of REC revenues included in base rates and actual REC revenues. Recovery mechanism for single capital investments that in total exceed 1% of existing rate base when a general rate case has occurred within the preceding 18 months.
OPUC	Forecasted	Annual TAM based on forecasted net variable power costs; no true-up to actual net variable power costs. PCAM under which 90% of the difference between forecasted net variable power costs set under the annual TAM and actual net variable power costs is deferred and reflected in future rates. The difference between the forecasted and actual net variable power costs must fall outside of an established asymmetrical deadband range and is also subject to an earnings test. Renewable Adjustment Clause to recover the revenue requirement of new renewable resources and associated transmission costs that are not reflected in general rates. Balancing account for proceeds from the sale of RECs.
WPSC	Forecasted or historical with known and measurable changes(1)	ECAM under which 70% of the difference between base net power costs set during a general rate case and actual net power costs is deferred and reflected in future rates. REC and sulfur dioxide revenue adjustment mechanism to provide for recovery or refund of 100% of any difference between actual REC and sulfur dioxide revenues and the level forecasted in base rates.
WUTC	Historical with known and measurable changes	Deferral mechanism of costs for up to 24 months of new base load generation resources and eligible renewable resources and related transmission that qualify under the state's emissions performance standard and are not reflected in base rates. REC revenue tracking mechanism to provide for the credit of Washington-allocated REC revenues.
IPUC	Historical with known and measurable changes	ECAM under which 90% of the difference between base net power costs set during a general rate case and actual net power costs is deferred and reflected in future rates. Also provides for recovery or refund of 100% of the difference between the level of REC revenues included in base rates and actual REC revenues and 90% of the level of sulfur dioxide revenues included in base rates and actual sulfur dioxide revenues.
CPUC	Forecasted	PTAM for major capital additions that allows for rate adjustments outside of the context of a traditional general rate case for the revenue requirement associated with capital additions exceeding $50 million on a total-company basis. Filed as eligible capital additions are placed into service. Energy Cost Adjustment Clause that allows for an annual update to actual and forecasted net variable power costs. PTAM for attrition, a mechanism that allows for an annual adjustment to costs other than net variable power costs.

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

MidAmerican Energy

Iowa law 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 2,285 MW (nominal ratings) of wind-powered generating facilities in-service as of December 31, 2014, excluding the wind-powered generating facilities discussed below. These ratemaking principles authorize a fixed rate of return on equity for the respective generating facilities over the regulatory life of the facilities. As of December 31, 2014, these generating facilities totaled $3.3 billion, or 32%, of MidAmerican Energy's property, plant and equipment, net, and were subject to these ratemaking principles at a weighted average return on equity of 12.0% with a weighted average remaining life of 22 years.

Additionally, in August 2013, the IUB approved ratemaking principles related to the construction of up to 1,050 MW (nominal ratings) of wind-powered generating facilities, 555 MW (nominal ratings) of which were in-service as of December 31, 2014, and are not reflected in the determination of MidAmerican Energy's Iowa retail electric base rates implemented in July 2014. The ratemaking principles establish a cost cap of $1.9 billion, including AFUDC, for the construction of 1,050 MW (nominal ratings) of wind-powered generating facilities and provide for a fixed rate of return on equity of 11.625% over the proposed 30-year useful lives of those facilities in any future Iowa rate proceeding. Until such time as these generation assets are reflected in rates, and ceasing thereafter, MidAmerican Energy will reduce its Iowa energy adjustment clause recoveries by $3 million in 2015, $7 million in 2016 and $10 million for each calendar year thereafter. In February 2015, the IUB approved ratemaking principles related to the construction of up to 162 MW (nominal ratings) of wind-powered generating facilities expected to be placed in-service by the end of 2015. The ratemaking principles establish a cost cap of $243 million, including AFUDC, and provide for a fixed rate of return on equity of 11.5% over the proposed 30-year useful lives of those facilities in any future Iowa rate proceeding. Until such time as these generation assets are reflected in rates, and ceasing thereafter, MidAmerican Energy will reduce its Iowa energy adjustment clause recoveries by $2 million per year. The cost caps ensure that, as long as the total costs of each project are below the respective cap, the investment will be deemed prudent in any future Iowa rate proceeding.

In July 2014, the IUB issued an order approving new retail electric base rates for MidAmerican Energy's Iowa customers. The order allows MidAmerican Energy to increase its base rates over approximately three years and will result in 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 approves the implementation of two new adjustment clauses. One clause relates to retail energy production costs such as fuel, fuel transportation and the impacts of the production tax credit. The second clause relates to certain electric transmission charges. The adjustment clauses provide for recovery of these costs from customers based on MidAmerican Energy's forecasted annual costs, with the variance between actual and forecasted costs to be recovered or credited in the following year. The order also approves seasonal pricing that results in a greater difference between higher base rates in effect for June through September and base rates applicable to the remaining months of the year, which MidAmerican Energy expects will shift an additional 15-25% of annual earnings into the June through September period. Additionally, the order approves 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%. The customer portion of any sharing reduces rate base. The changes in seasonal pricing, adjustment clauses and new revenue sharing mechanism were effective with final base rates. MidAmerican Energy and the Iowa Office of Consumer Advocate 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%.

Effective with the new Iowa electric retail rates in July 2014, MidAmerican Energy has an energy cost adjustment mechanism in Iowa. Accordingly, 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, effective with the new electric retail rates in Iowa and Illinois in July and December 2014, respectively, MidAmerican Energy has transmission adjustment clauses to recover certain transmission charges related to retail customers in those jurisdictions. The adjustment mechanisms reduce the regulatory lag for the recovery of energy and transmission costs related to retail electric customers in these jurisdictions. 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 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 Base Tariff Energy Rates ("BTER"), based on the last 12 months 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 Deferred Energy Accounting Adjustment ("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. The Nevada Utilities also file annually for the recovery of lost revenue that is attributable to the measurable and verifiable effects associated with the implementation of efficiency and conservation programs approved by the PUCN, as well as, the implementation costs of energy efficiency programs.

The Nevada Utilities became physically interconnected for the first time on January 1, 2014 and are presently joint dispatching generation facilities pursuant to an interim joint dispatch agreement approved by the FERC. In October 2014, the Nevada Utilities filed a motion for renewal of the interim joint dispatch agreement to extend the agreement through December 2015 and received acceptance from the FERC in November 2014. The Nevada Utilities are presently seeking PUCN approval of a long-term joint dispatch agreement, which will be filed with the FERC in time to go into effect on January 1, 2016.

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. During such reviews, the Utilities must 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 is pending before the FERC. The filings demonstrated that MidAmerican Energy satisfied the FERC's requirements for market-based rate authority. The Nevada Utilities' most recent triennial filing was made in July 2013 and approved by the FERC in April 2014. 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 wholesale transmission services are regulated by the FERC under cost-based regulation subject to PacifiCorp's OATT. These services are offered on a non-discriminatory basis, which means that all potential customers are provided an equal opportunity to access the transmission system. PacifiCorp's transmission business is managed and operated independently from its wholesale marketing business in accordance with the FERC's Standards of Conduct. PacifiCorp has made several required compliance filings in accordance with these rules.

In December 2011, PacifiCorp adopted a cost-based formula rate under its OATT for its transmission services. Cost-based formula rates are intended to be an effective means of recovering PacifiCorp's investments and associated costs of its transmission system without the need to file rate cases with the FERC, although the formula rate results are subject to discovery and challenges by the FERC and intervenors. A significant portion of these services are provided to PacifiCorp's commercial and trading function.

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 for 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 Nevada Utilities' wholesale transmission services are regulated by the FERC under cost-based regulation subject to the Nevada Utilities' OATT. These services are offered on a non-discriminatory basis, which means that all potential customers, including the Nevada Utilities, are provided an equal opportunity to access the transmission system. The Nevada Utilities' transmission business is managed and operated independently from its wholesale marketing business in accordance with the FERC's Standards of Conduct. The Nevada Utilities have made several required compliance filings in accordance with these rules.

The FERC has established an extensive number of mandatory reliability standards developed by the North American Electric Reliability Corporation ("NERC") and the Western Electricity Coordinating Council ("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 and NV Energy 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, 17 dams associated with PacifiCorp's hydroelectric generating facilities licensed with the FERC are classified as "high hazard potential," meaning it is probable in the event of dam failure that loss of human life in the downstream population could occur. The FERC provides guidelines followed by PacifiCorp in developing public safety programs that consist of an owner's dam safety program and emergency action plans.

PacifiCorp's Klamath River hydroelectric system is the only significant hydroelectric system for which PacifiCorp is currently engaged in the relicensing process with the FERC. Refer to Note 16 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for an update regarding hydroelectric relicensing for PacifiCorp's Klamath River hydroelectric system.

Nuclear Regulatory Commission

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.

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.

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 are: nuclear liability, property damage or loss and nuclear worker liability.

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 2015 on each of the areas studied. We 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 next price control, Electricity Distribution 1 ("ED1"), will be 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 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 that have not already been remunerated through the allowance for regulatory depreciation or the allowance for expenditures that are, or are to be, remunerated in the year in which they are incurred;
- 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; and
- an allowance in respect of the repair of the pension deficits in the defined benefit pension schemes sponsored by each of the licensees.

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 with 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.

The current electricity distribution price control became effective April 1, 2010 and is due to terminate on March 31, 2015, and will be immediately replaced with a new price control (in line with the traditional timetable which involved replacement of price controls every five years). 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 each agreed to Ofgem's proposals for the resetting of the formula that commenced April 1, 2010.

The current price control was implemented following a review that led Ofgem to increase the allowed revenue for the Northern Powergrid Distribution Companies. As a result, excluding the effects of incentive schemes, the base allowed revenue of Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc increased by approximately 7.7% and 6.5%, respectively, plus inflation (as measured by the United Kingdom's Retail Prices Index) in each of the five regulatory years that commenced April 1, 2010. However, in December 2013, the Northern Powergrid Distribution Companies agreed to defer the collection of $47 million of 2013/14 revenues until the regulatory year commencing April 1, 2015.

Ofgem has completed the price control review that will result in a new price control effective April 1, 2015. The license modifications that give effect to the price control were published by Ofgem on February 3, 2015 and may be subject to appeal to the CMA if an appeal is filed by March 3, 2015. This is the first of the price control reviews to apply to electricity distribution in Great Britain that Ofgem has undertaken since it completed its review of network regulation (known as the RPI-X @ 20 project). Under the new price control review process, which is expected to remain in place until March 31, 2023, Ofgem will:

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

Many other aspects of the current price control will remain in place.

Under Ofgem's proposals, 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 will decrease by approximately 18% and 12%, respectively, in 2015-16 before the addition of inflation (as measured by the United Kingdom's Retail Prices Index) to derive the final price change. In the following year, base revenues will decrease by a further 1% for Northern Powergrid (Northeast) Limited and by 0.2% for Northern Powergrid (Yorkshire) plc before the addition of inflation. In subsequent years, base allowed revenues will increase approximately 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 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

Domestic

The Cordova, Saranac, Power Resources, Topaz, Agua Caliente, Solar Star, Bishop Hill II, Jumbo Road and Pinyon Pines independent power projects are Exempt Wholesale Generators ("EWG") under the Energy Policy Act while the Yuma, 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, Power Resources, 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.

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.

Foreign

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 the Company's 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.

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 the Company's current and future operations. In addition to imposing continuing compliance obligations and capital expenditure requirements, these laws and regulations provide regulators with the authority to levy substantial penalties for noncompliance including fines, injunctive relief and other sanctions. These laws and regulations are administered by the EPA and various state, 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 7 of this Form 10-K for additional information regarding environmental laws and regulations and "Liquidity and Capital Resources" for the Company's forecasted environmental-related capital expenditures.

Item 1A. Risk Factors

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

Our Corporate and Financial Structure Risks

We are a holding company and depend on distributions from subsidiaries, including joint ventures, to meet our obligations.

We are a holding company with no material assets other than the ownership interests in our subsidiaries and joint ventures, collectively referred to as our subsidiaries. Accordingly, cash flows and the ability to meet our obligations are largely dependent upon the earnings of our subsidiaries and the payment of such earnings to us in the form of dividends or other distributions. Our subsidiaries are separate and distinct legal entities and have no obligation, contingent or otherwise, to pay amounts due pursuant to our senior debt, junior subordinated debt or our other obligations, or to make funds available, whether by dividends or other payments, for the payment of amounts due pursuant to our senior debt, junior subordinated debt or our other obligations, and do not guarantee the payment of any of our 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 our regulated utility subsidiaries to distribute profits.

We are substantially leveraged, the terms of our existing senior and junior subordinated debt do not restrict the incurrence of additional debt by us or our subsidiaries, and our senior debt is structurally subordinated to the debt of our subsidiaries, each of which could adversely affect our consolidated financial results.

A significant portion of our capital structure is comprised of debt, and we expect 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 at our subsidiaries. As of December 31, 2014, we had the following outstanding obligations:

- senior unsecured debt of $7.9 billion;
- junior subordinated debentures of $3.8 billion;
- borrowings under our commercial paper program of $395 million;
- commitments to provide equity contributions in support of the construction of certain solar and wind projects totaling $944 million; and
- guarantees and letters of credit in respect of subsidiary and equity method investments aggregating $217 million.

Our consolidated subsidiaries also have significant amounts of outstanding debt, which totaled $27.0 billion as of December 31, 2014. These amounts exclude (a) trade debt, (b) preferred stock obligations, (c) letters of credit in respect of subsidiary debt, and (d) our share of the outstanding debt of our own or our subsidiaries' equity method investments.

Given our substantial leverage, we may not have sufficient cash to service our debt, which could limit our 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 our capital needs may exceed our ability to fund them. Our leverage could also impair our credit quality or the credit quality of our 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 our debt does not limit our ability or the ability of our subsidiaries to incur additional debt or issue preferred stock. Accordingly, we or our subsidiaries could enter into acquisitions, new financings, refinancings, recapitalizations, capital leases or other highly leveraged transactions that could significantly increase our or our subsidiaries' total amount of outstanding debt. The interest payments needed to service this increased level of debt could adversely affect our consolidated financial results. Many of our 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 our ability to comply with these covenants may be affected by events beyond our 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 our other debt, we may not have sufficient funds to repay all of the accelerated debt simultaneously, and the other risks described under "Our Corporate and Financial Structure Risks" may be magnified as well.

Because we are a holding company, the claims of our senior debt holders are structurally subordinated with respect to the assets and earnings of our subsidiaries. Therefore, the rights of our 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, LLC'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 our debt.

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

Our senior unsecured debt is rated by various rating agencies. We cannot assure that our senior unsecured debt rating will not be reduced in the future. Although none of our outstanding debt has rating-downgrade triggers that would accelerate a repayment obligation, a credit rating downgrade would increase our borrowing costs and commitment fees on our revolving credit agreements and other financing arrangements, perhaps significantly, and would cause our obligations under commitments to provide equity contributions in support of the construction of solar and wind projects by certain of our indirect subsidiaries to be supported by cash collateral or letters of credit. In addition, we would likely be required to pay a higher interest rate in future financings, and the potential pool of investors and funding sources would likely decrease. Further, access to the commercial paper market, our principal source of short-term borrowings, could be significantly limited, resulting in higher interest costs.

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

Most of our subsidiaries' large wholesale customers, suppliers and counterparties require our subsidiaries to have sufficient creditworthiness in order to enter into transactions, particularly in the wholesale energy markets. If the credit ratings of our subsidiaries were to decline, especially below investment grade, financing costs and borrowings would likely increase because certain counterparties may require collateral in the form of cash, a letter of credit or some other form of security for existing transactions and as a condition to entering into future transactions with our subsidiaries. Such amounts may be material and may adversely affect our subsidiaries' liquidity and cash flows.

Our majority shareholder, Berkshire Hathaway, could exercise control over us in a manner that would benefit Berkshire Hathaway to the detriment of our creditors.

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

Our Business Risks

Much of our growth has been achieved through acquisitions, including the AltaLink Transaction, and any such acquisitions may not be successful.

Much of our growth has been achieved through acquisitions. Future acquisitions may range from buying individual assets to the purchase of entire businesses. On December 19, 2013, we completed the NV Energy Transaction and we completed the AltaLink Transaction on December 1, 2014. We will continue to investigate and pursue opportunities for future acquisitions that we believe, but cannot assure you, may increase value and expand or complement existing businesses. We 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 our subsidiaries. In addition, the final orders of regulatory authorities approving acquisitions may be subject to appeal by third parties. The diversion of management's attention and any delays or difficulties encountered in connection with the approval and integration of the acquired operations could adversely affect our combined businesses and financial results and could impair our ability to realize the anticipated benefits of the acquisition.

We cannot assure you that future acquisitions, if any, or any integration efforts, including those related to the AltaLink Transaction, will be successful, or that our ability to repay our obligations will not be adversely affected by any future acquisitions.

Our subsidiaries are subject to operating uncertainties and events beyond our control that impact the costs to operate, maintain, repair and replace utility and interstate natural gas pipeline systems, which could adversely affect our 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 our control. These potential events include the breakdown or failure of our thermal, nuclear, hydroelectric 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 tribal or First Nations land; terrorist activities or military or other actions, including cyberattacks; fuel shortages or interruptions; unavailability of critical equipment, materials and supplies; low water flows and other weather-related impacts; performance below expected levels of output, capacity or efficiency; operator error; third party excavation errors; unexpected degradation of our 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 our high hazard potential hydroelectric facilities, it is probable that loss of human life, disruption of lifeline facilities and property damage could occur in the downstream population and civil or other penalties could be imposed by the FERC. Any of these events or other operational events could significantly reduce or eliminate our subsidiaries' revenue or significantly increase their expenses, thereby reducing the availability of distributions to us. For example, if our subsidiaries cannot operate their electricity or natural gas facilities at full capacity due to damage caused by a catastrophic event, their revenue could decrease and their expenses could increase due to the need to obtain energy from more expensive sources. Further, we and our subsidiaries self-insure many risks, and current and future insurance coverage may not be sufficient to replace lost revenue or cover repair and replacement costs. The scope, cost and availability of our and our subsidiaries' insurance coverage may change, including the portion that is self-insured. Any reduction of our subsidiaries' revenue or increase in their expenses resulting from the risks described above, could adversely affect our consolidated financial results.

We and our subsidiaries are subject to extensive federal, state, local and foreign legislation and regulation, including numerous environmental, health, safety, reliability and other laws and regulations that affect us and our subsidiaries' 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 us and our subsidiaries.

We and our subsidiaries are required to comply with numerous federal, state, local and foreign laws and regulations as described in Item 1 of this Form 10-K that have broad application to us and our subsidiaries and limit our ability to independently make and implement management decisions regarding, among other items, acquiring businesses; constructing, acquiring or disposing of operating assets; operating and maintaining generating facilities and transmission and distribution system assets; 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 our safety and compliance programs and procedures and are implemented and enforced by federal, state and local regulatory agencies, such as, among others, the Occupational Safety and Health Administration, the FERC, the EPA, the 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 our subsidiaries to obtain and comply with a wide variety of licenses, permits, inspections, audits and other approvals. Further, compliance with laws and regulations can require significant capital and operating expenditures, including expenditures for new equipment, inspection, cleanup costs, removal and remediation costs, damages arising out of contaminated properties and refunds, fines, penalties and injunctive measures affecting operating assets for failure to comply with environmental regulations. Compliance activities pursuant to existing or new laws and regulations could be prohibitively expensive or otherwise uneconomical. As a result, we could be required to shut down some facilities or materially alter their operations. Further, our subsidiaries may not be able to obtain or maintain all required environmental or other regulatory approvals and permits for their 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 our subsidiaries from operating their facilities, developing or favorably locating new facilities or expanding existing facilities. If our subsidiaries fail to comply with any environmental or other regulatory requirements, they may be subject to penalties and fines or other sanctions, including changes to the way our electricity generating facilities are operated that may adversely impact generation 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 our consolidated financial results. Not being able to operate existing facilities or develop new generating facilities to meet customer electricity needs could require our subsidiaries to increase their purchases of electricity on the wholesale market, which could increase market and price risks and adversely affect our consolidated financial results.

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

Implementing actions required under, and otherwise complying with, new federal and state laws and regulations and changes in existing ones are among the most challenging aspects of managing utility operations. We cannot accurately predict the type or scope of future laws and regulations that may be enacted, changes in existing ones or new interpretations by agency orders or court decisions nor can we determine their impact on us at this time; however, any one of these could adversely affect our consolidated financial results through higher capital expenditures and operating costs or restrict or otherwise cause an adverse change in how we operate our subsidiaries. To the extent that our regulated subsidiaries are not allowed by their regulators to recover or cannot otherwise recover the costs to comply with new laws and regulations or changes in existing ones, the costs of complying with such additional requirements could have a material adverse effect on our consolidated financial results. Additionally, even if such costs are recoverable in rates, if they are substantial and result in rates increasing to levels that substantially reduce customer demand, this could have a material adverse effect on our consolidated financial results.

Recovery of costs and certain activities by our regulated subsidiaries are subject to regulatory review and approval, and the inability to recover costs or undertake certain activities may adversely affect our consolidated financial results.

State Rate Proceedings

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 we will be able to realize a reasonable rate of return.

In certain states where energy cost adjustment mechanisms are in place, energy cost increases above the level assumed in establishing base rates 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 our 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 our 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. 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 our 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 our Pipeline Companies an opportunity to earn a reasonable rate of return. Nevertheless, the rates the FERC authorizes our 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 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 we may own, including AltaLink, will be selected by the AESO to build, own and operate transmission facilities, even if our market participant operates in the relevant geographic area, or that our market participant will be successful in any such competitive process in which it may participate.

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

Through our subsidiaries, we actively pursue, develop and construct new or expanded facilities. We expect that these subsidiaries will incur substantial annual capital expenditures over the next several years. Such expenditures include and may include in the future, among others, construction and other costs for new electricity generating facilities, 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 our suppliers, customers and contractors. Certain of our 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 our subsidiaries are able to charge their 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 our consolidated financial results.

Furthermore, our subsidiaries depend upon both internal and external sources of liquidity to provide working capital and to fund capital requirements. In some cases, like our solar projects, we have committed to provide significant amounts of equity to our subsidiaries that are engaged in construction projects. If we do not provide needed funding to our subsidiaries and the subsidiaries are unable to obtain funding from external sources, they may need to postpone or cancel planned capital expenditures, and in the case of our subsidiaries' solar and wind projects for which we have provided equity commitment agreements, could result in a default by us.

Failure to construct these planned projects could limit opportunities for growth, increase operating costs and adversely affect the reliability of electricity service to our customers. For example, if PacifiCorp is not able to expand its existing portfolio of generating facilities, it may be required to enter into long-term wholesale electricity purchase contracts or purchase wholesale electricity at more volatile and potentially higher prices in the spot markets to serve retail loads.

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

A significant sustained decrease in demand for electricity or natural gas in the markets served by our subsidiaries would decrease our operating revenue, could impact our planned capital expenditures and could adversely affect our consolidated financial results. Factors that could lead to a decrease in market demand include, among others:

- a depression, recession or other adverse economic condition that results in a lower level of economic activity or reduced spending by consumers on electricity 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 our Pipeline Companies' systems, including new shale gas sources;
- efforts by customers, legislators and regulators to reduce the consumption of electricity generated or distributed by our subsidiaries through various conservation, energy efficiency and distributed generation measures and programs;
- laws mandating or encouraging renewable energy sources, which may decrease the demand for natural gas;
- 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.

Our 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 our subsidiaries operate, demand for electricity peaks during the summer months when irrigation and cooling needs are higher. Market prices for electricity also generally peak at that time. In other areas, demand for electricity peaks during the winter. In addition, demand for natural gas and other fuels generally peaks during the winter when heating needs are higher. 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 our 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 our subsidiaries may fluctuate substantially on a seasonal and quarterly basis. We have historically provided less service, and consequently earned less income, when weather conditions are mild. Unusually mild weather in the future may adversely affect our consolidated financial results through lower revenue or margins. Conversely, unusually extreme weather conditions could increase our costs to provide services and could adversely affect our consolidated financial results. The extent of fluctuation in our consolidated financial results may change depending on a number of factors related to our subsidiaries' regulatory environment and contractual agreements, including their ability to recover energy costs, the existence of revenue sharing provisions and terms of the wholesale sale contracts.

Our subsidiaries are subject to market risk associated with the wholesale energy markets, which could adversely affect our consolidated financial results.

In general, our primary market risk is adverse fluctuations in the market price of wholesale electricity and fuel, including natural gas, coal and fuel oil, which is compounded by volumetric changes affecting the availability of or demand for electricity and fuel. The market price of wholesale electricity may be influenced by several factors, such as the adequacy or type of generating capacity, scheduled and unscheduled outages of generating facilities, prices and availability of fuel sources for generation, disruptions or constraints to transmission and distribution facilities, weather conditions, demand for electricity, economic growth and changes in technology. Volumetric changes are caused by fluctuations in generation or changes in customer needs that can be due to the weather, electricity and fuel prices, the economy, regulations or customer behavior. For example, 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 in certain states, the risks associated with changes in market prices may not be fully mitigated.

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

The ongoing threat of terrorism and the impact of military or other actions by nations or politically, ethnically or religiously motivated organizations regionally or globally may create increased political, economic, social and financial market instability, which could subject our subsidiaries' 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, including cyberattacks. Cyberattacks could adversely affect our subsidiaries' ability to operate their facilities, information technology and business systems, or compromise confidential customer and employee information. Political, economic, social or financial market instability or damage to or interference with the operating assets of our subsidiaries, customers or suppliers may result in business interruptions, lost revenue, higher commodity prices, disruption in fuel supplies, lower energy consumption and unstable markets, particularly with respect to electricity and natural gas, and increased security, repair or other costs, any of which may materially adversely affect us and our subsidiaries in ways that cannot be predicted at this time. Any of these risks could materially affect our consolidated financial results. Furthermore, instability in the financial markets as a result of terrorism, sustained or significant cyberattacks, or war could also materially adversely affect our and our subsidiaries' ability to raise capital.

MidAmerican Energy is 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. The prolonged unavailability of Quad Cities Station could have a materially adverse effect on MidAmerican Energy'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 MidAmerican Energy's resources, including insurance coverage.

Certain of our subsidiaries are subject to the risk that customers will not renew their contracts or that our subsidiaries will be unable to obtain new customers for expanded capacity, each of which could adversely affect our 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 our subsidiaries are unable to renew, remarket, or find replacements for their customer agreements on favorable terms, our sales volumes and operating revenue would be exposed to reduction and increased volatility. For example, without the benefit of long-term transportation agreements, we cannot assure that the Pipeline Companies will be able to transport natural gas at efficient capacity levels. Similarly, without long-term power purchase agreements, we cannot assure that our 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 our consolidated financial results. The replacement of any existing long-term agreements depends on market conditions and other factors that may be beyond our subsidiaries' control.

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

Our subsidiaries are subject to counterparty credit risk related to contractual payment obligations with wholesale suppliers and customers. Adverse economic conditions or other events affecting counterparties with whom our subsidiaries conduct business could impair the ability of these counterparties to meet their payment obligations. Our subsidiaries depend on these counterparties to remit payments on a timely basis. We continue to monitor the creditworthiness of our wholesale suppliers and customers in an attempt to reduce the impact of any potential counterparty default. If strategies used to minimize these risk exposures are ineffective or if any of our subsidiaries' wholesale suppliers' or customers' financial condition deteriorates or they otherwise become unable to pay, it could have a significant adverse impact on our liquidity and our consolidated financial results.

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

Our subsidiaries are subject to counterparty performance risk related to performance of contractual obligations by wholesale suppliers, customers and contractors. Each subsidiary 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.

Our subsidiaries rely on wholesale customers to take delivery of the energy they have committed to purchase. Failure of customers to take delivery may require these subsidiaries to find other customers to take the energy at lower prices than the original customers committed to pay. If our subsidiaries' wholesale customers are unable to fulfill their obligations, there may be a significant adverse impact on our consolidated financial results.

Generally, a single customer purchases the energy from our 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, we cannot assure that our unregulated power generators will be able to operate profitably.

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

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

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

Costs of providing our defined benefit pension and other postretirement benefit plans 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, changes in benefit design, tax deductibility and funding limits, changes in laws and government regulation and our required or voluntary contributions made to the plans. Certain of our 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, we will likely be required to make cash contributions to fund these plans in the future. Additionally, our plans have investments in domestic and foreign equity and debt securities and other investments that are subject to loss. Losses from investments could add to the volatility, size and timing of future contributions.

In addition, MidAmerican Energy is required to fund over time the projected costs of decommissioning Quad Cities Station, a nuclear power plant. Funds MidAmerican Energy has invested in a nuclear decommissioning 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 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 liquidity by reducing its available cash.

We own investments and projects located in foreign countries that are exposed to increased economic, regulatory and political risks.

We own and may acquire significant energy-related investments and projects outside of the United States, including our recent acquisition of AltaLink. In addition to any disruption in the global financial markets, the economic, regulatory and political conditions in some of the countries where we have operations or are 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. We may not choose to or be capable of either fully insuring against or effectively hedging these risks.

We are exposed to risks related to fluctuations in foreign currency exchange rates.

Our business operations and investments outside the United States increase our risk related to fluctuations in foreign currency exchange rates, primarily the British pound and the Canadian dollar. Our principal reporting currency is the United States dollar, and the value of the assets and liabilities, earnings, cash flows and potential distributions from our foreign operations changes with the fluctuations of the currency in which they transact. We 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 our consolidated financial results.

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 our and our subsidiaries' ability to obtain debt financing or to draw upon or renew existing credit facilities and have other adverse effects on us and our subsidiaries.

Disruptions in the financial markets could affect our and our subsidiaries' ability to obtain debt financing or to draw upon or renew existing credit facilities and have other adverse effects on us and our subsidiaries. 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 our and our subsidiaries' ability to access funds on favorable terms or at all. If we or our subsidiaries are unable to access the bank and debt markets to meet liquidity and capital expenditure needs, it may adversely affect the timing and amount of our capital expenditures, acquisition financing and our consolidated financial results.

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

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

Item 1B. Unresolved Staff Comments

Not applicable.

Item 2. Properties

The Company's energy properties consist of the physical assets necessary to support its electricity and natural gas businesses. Properties of the Company's electricity businesses include electric generation, transmission and distribution facilities, as well as coal mining assets that support certain of the Company's electric generating facilities. Properties of the Company'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 Company has rights-of-way, mineral rights and water rights that enable the Company to utilize its facilities. It is the opinion of the Company's management that the principal depreciable properties owned by the Company 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 the Company's energy properties, refer to Item 1 of this Form 10-K and Notes 4, 5 and 22 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

The following table summarizes the electric generating facilities of BHE's subsidiaries that are in operation as of December 31, 2014:

Energy Source	Entity	Location by Significance	Facility Net Capacity (MW)	Net Owned Capacity (MW)
Natural gas and other	PacifiCorp, MidAmerican Energy, NV Energy and BHE Renewables	Nevada, Utah, Iowa, Illinois, Washington, Oregon, New York, Texas and Arizona	10,812	10,391
Coal	PacifiCorp, MidAmerican Energy and NV Energy	Iowa, Wyoming, Utah, Arizona, Montana, Colorado and Nevada	17,329	10,270
Wind	PacifiCorp, MidAmerican Energy and BHE Renewables	Iowa, Wyoming, Washington, California, Oregon and Illinois	4,252	4,243
Hydroelectric	PacifiCorp, MidAmerican Energy and BHE Renewables	Washington, Oregon, The Philippines, Idaho, California, Utah, Hawaii, Montana, Illinois and Wyoming	1,307	1,285
Solar	BHE Renewables	California and Arizona	1,240	1,092
Nuclear	MidAmerican Energy	Illinois	1,816	454
Geothermal	PacifiCorp and BHE Renewables	California and Utah	370	370
		Total	37,126	28,105

Additionally, BHE's subsidiaries have electric generating facilities that are under construction in Iowa, Texas, California and Nevada as of December 31, 2014 having total Facility Net Capacity and Net Owned Capacity of 1,119 MW.

The right to construct and operate the Company'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. The Company believes that each of its energy subsidiaries has satisfactory title or interest to all of the real property making up their respective facilities in all material respects.

Item 3. Legal Proceedings

None.

Item 4. Mine Safety Disclosures

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

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

BHE'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 Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

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,				
	2014(1)	2013(1)	2012	2011	2010
Consolidated Statement of Operations Data:					
Operating revenue	$ 17,326	$ 12,635	$ 11,548	$ 11,173	$ 11,127
Net income	2,122	1,676	1,495	1,352	1,310
Net income attributable to BHE shareholders	2,095	1,636	1,472	1,331	1,238

	As of December 31,				
	2014(1)	2013(1)	2012	2011	2010
Consolidated Balance Sheet Data:					
Total assets	$ 82,304	$ 70,000	$ 52,467	$ 47,718	$ 45,668
Short-term debt	1,445	232	887	865	320
Long-term debt, including current maturities:					
BHE senior debt	7,860	6,616	4,621	5,363	5,371
BHE subordinated debt	3,794	2,594	—	22	315
Subsidiary debt	26,995	22,802	16,114	13,687	13,805
Total BHE shareholders' equity	20,442	18,711	15,742	14,092	13,232

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

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 corporate 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):

	2014	2013	Change		2013	2012	Change	
Net income attributable to BHE shareholders:								
PacifiCorp	$ 700	$ 681	$ 19	3%	$ 681	$ 539	$ 142	26%
MidAmerican Funding	409	340	69	20	340	342	(2)	(1)
NV Energy	354	(43)	397	*	(43)	—	(43)	*
Northern Powergrid	412	335	77	23	335	394	(59)	(15)
BHE Pipeline Group	230	237	(7)	(3)	237	232	5	2
BHE Transmission	56	33	23	70	33	26	7	27
BHE Renewables	121	(20)	141	*	(20)	14	(34)	*
HomeServices	83	73	10	14	73	47	26	55
BHE and Other	(270)	—	(270)	*	—	(122)	122	100
Total net income attributable to BHE shareholders	$ 2,095	$ 1,636	$ 459	28	$ 1,636	$ 1,472	$ 164	11

* Not meaningful

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 current year 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 and acquisition 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, 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 our acquisition of NV Energy and higher charitable contributions.

Net income attributable to BHE shareholders increased $164 million for 2013 compared to 2012 due to the following:

- PacifiCorp's net income increased largely due to $87 million of lower net after-tax charges related to the USA Power litigation and certain fire and other damage claims. Excluding these charges, net income increased $55 million primarily due to higher retail rates and higher retail customer load, partially offset by higher energy costs, lower REC revenue and higher depreciation and amortization.
- MidAmerican Funding's net income decreased due to lower nonregulated revenue and margins as a result of greater competition, partially offset by higher regulated natural gas earnings on higher retail volumes and higher regulated electric earnings due, in part, to higher rates.
- NV Energy was acquired on December 19, 2013. The reported net loss 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 decreased due to lower income tax benefits, a one-time rebate to customers, unfavorable movements in regulatory provisions, lower distributed units, higher distribution expenses and the stronger United States dollar, partially offset by higher tariff rates.
- BHE Pipeline Group's net income increased as benefits from a contract restructuring, higher transportation revenue at Northern Natural Gas and lower interest expense were partially offset by lower operating revenue at Kern River on contract expirations and lower storage revenue on narrowing natural gas price spreads at Northern Natural Gas.
- BHE Transmission's net income increased due to higher equity earnings at ETT due to continued investment and additional plant placed in-service.
- BHE Renewables' net income decreased due to an impairment charge related to the equity investment in CE Generation totaling $114 million, after-tax and higher net interest costs, partially offset by additional solar and wind-powered generation, which resulted in higher operating revenue, operating expense and depreciation and amortization, and a favorable change in the valuation of a power purchase agreement derivative of $26 million.
- HomeServices' net income increased due to higher earnings at the franchise and brokerage businesses, partially offset by higher amortization of acquisition related costs and lower equity earnings at its mortgage joint venture due to lower refinancing activity. Operating revenue increased $497 million reflecting higher revenue from acquired businesses and higher average home sale prices and closed brokerage units at existing businesses.
- BHE and Other improved due to one-time state deferred income tax benefits recognized from a reduction in the apportioned state tax rate of $161 million, in part as a result of acquiring NV Energy, and lower interest expense.

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):

	2014	2013	Change		2013	2012	Change	
Operating revenue:								
PacifiCorp	$ 5,252	$ 5,147	$ 105	2%	$ 5,147	$ 4,882	$ 265	5%
MidAmerican Funding	3,762	3,413	349	10	3,413	3,247	166	5
NV Energy	3,241	(20)	3,261	*	(20)	—	(20)	*
Northern Powergrid	1,283	1,025	258	25	1,025	1,035	(10)	(1)
BHE Pipeline Group	1,078	952	126	13	952	968	(16)	(2)
BHE Transmission	62	—	62	*	—	—	—	*
BHE Renewables	623	355	268	75	355	166	189	*
HomeServices	2,144	1,809	335	19	1,809	1,312	497	38
BHE and Other	(119)	(46)	(73)	*	(46)	(62)	16	26
Total operating revenue	$ 17,326	$ 12,635	$ 4,691	37	$ 12,635	$ 11,548	$ 1,087	9
Operating income:								
PacifiCorp	$ 1,308	$ 1,275	$ 33	3%	$ 1,275	$ 1,034	$ 241	23%
MidAmerican Funding	423	357	66	18	357	369	(12)	(3)
NV Energy	791	(42)	833	*	(42)	—	(42)	*
Northern Powergrid	674	501	173	35	501	565	(64)	(11)
BHE Pipeline Group	439	446	(7)	(2)	446	465	(19)	(4)
BHE Transmission	16	(5)	21	*	(5)	(2)	(3)	*
BHE Renewables	314	223	91	41	223	93	130	*
HomeServices	125	129	(4)	(3)	129	62	67	*
BHE and Other	(44)	(49)	5	10	(49)	(19)	(30)	*
Total operating income	$ 4,046	$ 2,835	$ 1,211	43	$ 2,835	$ 2,567	$ 268	10

* Not meaningful

PacifiCorp

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 current year 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 the Lake Side 2 natural gas-fueled generating unit ("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, 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.

Operating revenue increased $265 million for 2013 compared to 2012 due to higher retail revenue of $337 million, partially offset by lower REC revenue of $74 million and lower wholesale revenue of $7 million. The increase in retail revenue was due to higher rates of $259 million and higher retail customer load of $78 million. Retail customer load increased 2.0% due to the impacts of hotter weather in the third quarter of 2013 and colder weather in the first and fourth quarters of 2013 on residential and commercial load, higher industrial customer usage primarily in the eastern portion of PacifiCorp's service territory and an increase in the average number of residential customers, partially offset by lower residential customer usage. Wholesale revenue decreased due to lower volumes of $46 million, partially offset by higher average prices of $39 million.

Operating income increased $241 million for 2013 compared to 2012 largely due to lower net charges totaling $140 million related to the USA Power litigation and certain fire and other damage claims. Excluding these charges, operating income increased $101 million due to the higher operating revenue, partially offset by higher energy costs of $106 million, higher depreciation and amortization of $37 million, due primarily to higher plant in-service and accelerated depreciation rates for Oregon's share of the Carbon Facility expected to be retired in April 2015, and higher operating expense of $21 million. Energy costs increased due to a higher average cost of purchased electricity, higher coal-fueled generation costs due to higher unit costs and volumes, reduced electricity swap settlement gains and higher natural gas volumes, partially offset by lower purchased electricity volumes, a lower average cost of natural gas and higher net deferrals of incurred net power costs.

MidAmerican Funding

Operating revenue increased $349 million for 2014 compared to 2013 due to higher regulated electric operating revenue of $55 million, higher regulated natural gas operating revenue of $172 million and higher nonregulated and other operating revenue of $122 million. 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 MidAmerican Energy's Multi-Value Projects ("MVPs"), which are expected to increase substantially as the projects are constructed over the next two years. Other electric revenue decreased $13 million primarily from lower steam sales, partially due to the expiration of a contract, and lower sales of RECs. 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.

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.

Operating revenue increased $166 million for 2013 compared to 2012 due to higher regulated electric operating revenue of $68 million and higher regulated natural gas operating revenue of $165 million, partially offset by lower nonregulated and other operating revenue of $67 million. Regulated electric operating revenue increased due to higher retail revenue of $82 million, partially offset by lower wholesale and other revenue of $14 million. Electric retail revenue increased due to higher rates in Iowa and Illinois totaling $36 million and a 2.4% increase in retail customer load due to higher usage per customer and customer growth. Electric wholesale and other revenue decreased due to lower volumes of $18 million, partially offset by higher average prices of $4 million. Regulated natural gas operating revenue increased $165 million for 2013 compared to 2012 due to higher retail volumes, primarily from colder temperatures in 2013, and an increase in recoveries through adjustment clauses from a higher average per-unit cost of gas sold of $64 million, partially offset by lower wholesale volumes. Nonregulated and other operating revenue decreased $67 million for 2013 compared to 2012 due to lower electricity volumes and prices, partially offset by higher natural gas prices and volumes.

Operating income decreased $12 million for 2013 compared to 2012 due to lower regulated electric operating income of $15 million and lower nonregulated and other operating income of $24 million, partially offset by higher regulated natural gas operating income of $27 million. Regulated electric operating income decreased as the higher operating revenue was more than offset by higher energy costs of $59 million, higher operating expense of $14 million and higher depreciation of $10 million. Energy costs increased due to higher purchased electricity prices, higher coal transportation costs from new agreements effective in 2013 and a higher average cost of natural gas, partially offset by lower natural gas and coal generation. Operating expense increased due to higher generating facility maintenance costs, primarily related to the expanded scope of work for the Louisa Generating Station outage, partially offset by lower distribution and other power generation maintenance. Depreciation increased $10 million due primarily to higher plant placed in-service in 2012, partially offset by a $14 million decrease from the impact of depreciation rate changes. Nonregulated and other operating income decreased $24 million due to lower electric margins. The decrease in nonregulated electric revenue and margins is due to competitive pressures that reduced the volumes and margins per unit. Regulated natural gas operating income increased $27 million due to the higher retail volumes.

NV Energy

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 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.

Operating revenue decreased $10 million for 2013 compared to 2012 due to the stronger United States dollar of $15 million and lower distribution revenue of $9 million, partially offset by higher contracting revenue of $15 million. Distribution revenue decreased due to the rebate to customers, net unfavorable movements in regulatory provisions of $26 million and lower units distributed of $27 million, partially offset by higher tariff rates of $86 million. Operating income decreased $64 million for 2013 compared to 2012 due to the lower distribution revenue, higher distribution operating expense of $15 million, higher pension expense of $12 million, the stronger United States dollar totaling $10 million, the write-off of hydrocarbon well exploration costs of $9 million and higher depreciation of $8 million.

BHE Pipeline Group

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 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.

Operating revenue decreased $16 million for 2013 compared to 2012 due to lower operating revenue at Kern River of $24 million, primarily from contract expirations, and higher operating revenue at Northern Natural Gas of $8 million due to an increase in transportation revenue of $10 million and gas sales of $7 million, both on higher volumes, partially offset by lower storage revenue of $9 million due to the narrowing of natural gas price spreads. Operating income decreased $19 million for 2013 compared to 2012 due to the lower operating revenue and higher cost of gas sold, partially offset by lower depreciation and amortization and lower operating expense. Operating expense decreased due to a nonrecurring charge in 2012 related to a customer business interruption claim, partially offset by higher maintenance costs.

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 for 2014 was $62 million. Operating income increased $21 million for 2014 compared to 2013 due to the AltaLink Transaction of $31 million, partially offset by higher operating expense primarily related to higher project development and acquisition costs.

BHE Renewables

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.

Operating revenue increased $189 million for 2013 compared to 2012 due to an increase from the Pinyon Pines and Bishop Hill Projects of $86 million, which were placed in-service at the end of the fourth quarter of 2012, an increase from the Topaz Project of $73 million, which began generating revenue during the first quarter of 2013 and had 241 MW of generation capacity in-service at the end of 2013, and a favorable movement in the valuation of the power purchase agreement derivative at Bishop Hill II of $26 million. Operating income increased $130 million for 2013 compared to 2012 due to the higher operating revenue, partially offset by higher depreciation and amortization of $38 million and higher operating expense of $19 million.

HomeServices

Operating revenue increased $335 million for 2014 compared to 2013 due to an 8.2% increase in closed brokerage units and a 11.1% 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 6.0% decrease in closed brokerage units and lower franchise revenue, partially offset by a 4.5% 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.

Operating revenue increased $497 million for 2013 compared to 2012 due to an increase from acquired businesses totaling $315 million and an increase from existing businesses totaling $182 million, reflecting a 7% increase in average home sale prices and an 8% increase in closed brokerage units. Operating income increased $67 million for 2013 compared to 2012 due to the higher operating income at the franchise and brokerage businesses, partially offset by higher amortization of acquisition related costs at acquired businesses. The increase in operating income attributable to existing businesses was $38 million.

BHE and Other

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.

Operating revenue increased $16 million for 2013 compared to 2012 from other entities acquired in 2013. Operating loss increased $30 million for 2013 compared to 2012 due to higher acquisition and other costs.

Consolidated Other Income and Expense Items

Interest Expense

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

	2014	2013	Change		2013	2012	Change	
Subsidiary debt	$ 1,280	$ 919	$ 361	39%	$ 919	$ 856	$ 63	7%
BHE senior debt and other	353	300	53	18	300	320	(20)	(6)
BHE junior subordinated debentures	78	3	75	*	3	—	3	*
Total interest expense	$ 1,711	$ 1,222	$ 489	40	$ 1,222	$ 1,176	$ 46	4

* Not meaningful

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. Interest expense increased $63 million for 2013 compared to 2012. Debt issuances at MidAmerican Funding ($850 million in April 2014 and $950 million in September 2013), Northern Powergrid (£151 million in July 2012), BHE Pipeline Group ($250 million in August 2012) and BHE Renewables ($1.0 billion in June 2013, $250 million in April 2013, $120 million in August 2012 and $850 million in February 2012) and acquired debt at BHE Renewables ($502 million in November 2012) increased interest expense, partially offset by scheduled maturities and principal repayments.

Interest expense on BHE senior debt and other increased $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 senior debt totaling $250 million in 2014. Interest expense on BHE senior debt and other decreased $20 million for 2013 compared to 2012 due to scheduled maturities of senior debt totaling $750 million in 2012, partially offset by the senior debt issuance in November 2013.

Interest expense on BHE junior subordinated debentures in 2014 and 2013 relates to junior subordinated debentures issued to certain Berkshire Hathaway subsidiaries ($2.6 billion in the fourth quarter of 2013 and $1.5 billion in the fourth quarter of 2014). In June 2014, BHE repaid at par value $300 million, plus accrued interest, of its junior subordinated debentures due December 2043.

Capitalized Interest

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.

Capitalized interest increased $30 million for 2013 compared to 2012 due to higher construction work-in-progress balances related to the Solar Star Projects and the Topaz Project.

Allowance for Equity Funds

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.

Allowance for equity funds increased $4 million for 2013 compared to 2012 due to higher construction work-in-progress balances related to additional wind-powered generation at MidAmerican Energy.

Other, Net

Other, net increased $14 million for 2014 compared to 2013 due to a full year of activity from NV Energy of $33 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, partially offset by 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 BHE charitable contributions in 2014.

Other, net increased $10 million for 2013 compared to 2012 due to benefits from the contract restructuring at Northern Natural Gas, higher investment gains and a favorable movement on the Pinyon Pines interest rate swaps, partially offset by the contributions to the NV Energy Foundation in 2013.

Income Tax Expense

Income tax expense increased $459 million for 2014 compared to 2013 and the effective tax rates were 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 Transaction 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 expense decreased $18 million for 2013 compared to 2012. The effective tax rates were 7% for 2013 and 9% for 2012. The decrease in the effective tax rate was due to deferred state income tax benefits from the impact of the NV Energy Transaction of $89 million and a change in estimate related to the state apportionment calculation of $72 million, higher recognized production tax credits of $39 million and higher deferred income tax benefits of $16 million from additional reductions in the United Kingdom corporate income tax rate, partially offset by changes in uncertain income tax positions due to benefits recognized in 2012, the impacts of ratemaking totaling $42 million and a favorable claim in 2012 associated with customer contributions of $30 million at Northern Powergrid.

Income tax effect of foreign income includes, among other items, deferred income tax benefits of $54 million in 2013 and $38 million in 2012 related to the enactment of reductions in the United Kingdom corporate income tax rate. 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. In July 2012, the corporate income tax rate was reduced from 25% to 24% effective April 1, 2012, with a further reduction to 23% effective April 1, 2013.

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, $0.023 and $0.022 per kilowatt hour was applied to 2014, 2013 and 2012 production, respectively, which resulted in $258 million, $247 million and $208 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):

	2014	2013	Change		2013	2012	Change	
Equity income (loss):								
ETT	$ 80	$ 46	$ 34	74%	$ 46	$ 35	$ 11	31%
Agua Caliente	27	30	(3)	(10)	30	24	6	25
CE Generation	$ (8)	$ (126)	118	94	$ (126)	$ (14)	(112)	*
HomeServices	2	10	(8)	(80)	10	20	(10)	(50)
Other	8	5	3	60	5	3	2	67
Total equity income (loss)	$ 109	$ (35)	$ 144	*	$ (35)	$ 68	$ (103)	*

* Not meaningful

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.

Equity (loss) income decreased $103 million for 2013 compared to 2012 primarily due to an impairment charge related to CE Generation and lower earnings at HomeServices' mortgage joint venture due to lower refinancing activity, partially offset by higher earnings at ETT due to continued investment and additional plant placed in-service and higher earnings at Agua Caliente due to revenue and earnings from additional generation capacity placed in-service.

Net Income Attributable to Noncontrolling Interests

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.

Net income attributable to noncontrolling interests increased $17 million for 2013 compared to 2012 primarily due to HomeServices' acquisition of HSF Affiliates in the fourth quarter of 2012.

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, 2014, the Company's total net liquidity was $5.2 billion as follows (in millions):

	BHE	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	AltaLink	Other	Total
Cash and cash equivalents	$ 3	$ 23	$ 30	$ 262	$ 5	$ 13	$ 281	$ 617
Credit facilities[1]	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
Total net liquidity	$ 1,580	$ 805	$ 394	$ 912	$ 55	$ 877	$ 620	$ 5,243
Credit facilities:								
Maturity dates	2017	2017, 2018	2015, 2018	2018	2017	2016, 2019	2015, 2018	
Largest single bank commitment as a % of total credit facilities	6%	7%	7%	12%	41%	28%	26%	

(1) Includes the drawn uncommitted credit facilities totaling $31 million at Northern Powergrid.

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, 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. 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. As of December 31, 2014, the Company had a current income tax receivable of $1.2 billion.

Net cash flows from operating activities for the years ended December 31, 2013 and 2012 were $4.7 billion and $4.3 billion, respectively. The increase was primarily due to improved operating results and other changes in working capital, partially offset by lower income tax receipts due to lower bonus depreciation benefits and investment tax credits. The Company received investment tax credits of $378 million in 2013 and $535 million in 2012.

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 are expected to benefit in 2015 due to bonus depreciation on qualifying assets placed in-service and for production tax credits earned on qualifying projects.

Investing Activities

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 Transaction 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 Transaction 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 and lower equity method investments. Refer to "Future Uses of Cash" for further discussion of capital expenditures.

Net cash flows from investing activities for the years ended December 31, 2013 and 2012 were $(10.2) billion and $(4.3) billion, respectively. The change was primarily due to the NV Energy Transaction, higher acquisitions at HomeServices, higher capital expenditures of $927 million and changes in restricted cash and investments related to proceeds from the issuance of long-term debt in 2013 at Solar Star Funding that is restricted for use in the construction of the Solar Star Projects, partially offset by the acquisitions in 2012 of Pinyon Pines I and II, Topaz, Bishop Hill II and Solar Star I and II and payments in 2012 to acquire a 49% interest in Agua Caliente.

Financing Activities

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.

In July 2014, NV Energy redeemed its $195 million variable-rate term loan due October 2014.

In June 2014, BHE repaid at par value $300 million, plus accrued interest, of its junior subordinated debentures due December 2043.

In April 2014, MidAmerican Energy issued $150 million of its 2.40% First Mortgage Bonds due March 2019, $300 million of its 3.50% First Mortgage Bonds due October 2024 and $400 million of its 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.

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.

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 Transaction 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.

Net cash flows from financing activities for the year ended December 31, 2012 were $477 million. Sources of cash totaled $2.2 billion and consisted of proceeds from subsidiary debt. Uses of cash totaled $1.7 billion and consisted mainly of repayments of subsidiary debt totaling $887 million and repayments of BHE senior and subordinated debt totaling $772 million.

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 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. Prudently incurred expenditures for compliance-related items, such as pollution-control technologies, replacement generation, nuclear decommissioning, hydroelectric relicensing, hydroelectric decommissioning and associated operating costs are generally incorporated into BHE's energy subsidiaries' regulated retail rates. Expenditures for certain assets may ultimately include acquisitions of existing assets.

Historical and forecasted 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			Forecasted		
	2012	2013	2014	2015	2016	2017
PacifiCorp	$ 1,346	$ 1,065	$ 1,066	$ 965	$ 773	$ 789
MidAmerican Funding	645	1,027	1,527	1,417	593	423
NV Energy	—	—	558	578	477	999
Northern Powergrid	454	675	675	788	576	543
BHE Pipeline Group	152	177	257	169	153	226
BHE Transmission	—	—	222	1,272	706	677
BHE Renewables	770	1,329	2,221	932	54	57
Other	13	34	29	38	33	37
Total	$ 3,380	$ 4,307	$ 6,555	$ 6,159	$ 3,365	$ 3,751

	Historical			Forecasted		
	2012	2013	2014	2015	2016	2017
Solar generation	$ 627	$ 1,323	$ 1,896	$ 859	$ 4	$ 209
Wind generation	306	404	1,052	866	5	—
Electric transmission	338	341	547	1,284	796	658
Environmental	264	228	258	176	133	117
Natural gas generation	232	156	178	33	60	484
Interstate pipeline transportation	35	29	76	48	15	91
Electric distribution and other	1,578	1,826	2,548	2,893	2,352	2,192
Total	$ 3,380	$ 4,307	$ 6,555	$ 6,159	$ 3,365	$ 3,751

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

- Solar generation includes the following:
  - Construction of the Topaz Project totaling $814 million for 2014, $652 million for 2013 and $560 million for 2012. The project is expected to cost up to $2.44 billion, including all interest costs during construction and the initial costs to acquire the project. The Topaz Project reached substantial completion on November 6, 2014, approximately five months ahead of schedule and is under budget. In conjunction with substantial completion, Topaz declared October 27, 2014 as the Commercial Operation Date in accordance with the power purchase agreement. Final completion under the engineering, procurement and construction agreement is expected to occur in March 2015.
  - Construction of the Solar Star Projects totaling $1.1 billion for 2014, $671 million for 2013 and $67 million for 2012. Subsidiaries of Solar Star Funding anticipate costs for the Solar Star Projects will total $744 million for 2015. The projects are expected to cost up to $2.75 billion, including all interest costs during construction and the initial costs to acquire the projects. The projects will be comprised of 13 blocks of solar panels with a net facility capacity of 579 MW. As of December 31, 2014, 519 MW of the Solar Star Projects were operating and delivering energy under the power purchase agreements, including 400 MW placed in-service under the construction contract. The projects expect to place an additional 179 MW in-service by no later than October 31, 2015. As of December 31, 2014, the projects were approximately 95% constructed compared to the engineering, procurement and construction schedule of 85%, which includes 1.6 million solar panels installed out of an expected total of 1.72 million. The projects are being constructed pursuant to fixed-price, date certain, turn-key engineering, procurement and construction contracts with a subsidiary of SunPower Corporation.

- Wind generation includes the following:
    - Construction of wind-powered generating facilities at MidAmerican Energy totaling $767 million for 2014, $401 million for 2013 and $168 million for 2012, excluding $406 million of costs in 2012 for which payments are due in December 2015. MidAmerican Energy placed in-service 511 MW (nominal ratings) during 2014, 44 MW (nominal ratings) during 2013 and 407 MW (nominal ratings) during 2012. MidAmerican Energy is constructing an additional 657 MW (nominal ratings) of wind-powered generating facilities, including 162 MW (nominal ratings) recently approved by the IUB, it expects to place in-service in 2015 with anticipated costs totaling $787 million.
    - Jumbo Road has spent $285 million in 2014 for the Jumbo Road Project, and expects to spend an additional $84 million for 2015. The project is expected to cost $408 million, including all interest costs during construction and the initial costs to acquire the project. The project will be comprised of 162 General Electric Company 1.85 MW wind turbines with a total capacity of 300 MW and is expected to achieve commercial operation by the end of the first quarter 2015.
    - Construction of the Bishop Hill Project totaling $138 million for 2012, which was placed in-service in 2012.
- Electric transmission includes investments for AltaLink's directly assigned projects from the AESO, PacifiCorp's costs primarily associated with 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.
- Natural gas generation includes costs for PacifiCorp's Lake Side 2, which was placed in-service in May 2014, the purchase of Nevada Power's purchase of the Las Vegas and Sun Peak natural gas-fueled generating facilities in December 2014 and additional generation capacity at the Nevada Utilities.
- Electric distribution and other 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.

On February 27, 2015, the Company acquired Grande Prairie Wind, LLC and Geronimo Community Solar Gardens, LLC, which each respectively own certain assets that will facilitate the development of up to 400 MW of wind-powered generating facilities in Nebraska and 74 MW of solar generating facilities in Minnesota. In addition to the capital expenditures above, the Company estimates the capital expenditures for the generating facilities will total $206 million in 2015 and $588 million in 2016.

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, 2014 (in millions):

	Payments Due By Periods				
	2015	2016-2017	2018-2019	2020 and After	Total
BHE senior debt	$ —	$ 400	$ 1,000	$ 6,475	$ 7,875
BHE junior subordinated debentures	—	—	—	3,794	3,794
Subsidiary debt	1,232	1,828	4,590	19,274	26,924
Interest payments on long-term debt(1)	1,872	3,637	3,307	23,129	31,945
Short-term debt	1,445	—	—	—	1,445
Fuel, capacity and transmission contract commitments(1)	2,327	3,318	2,356	8,777	16,778
Construction commitments(1)	1,280	135	11	9	1,435
Operating leases and easements(1)	143	222	151	861	1,377
Other(1)	243	390	381	1,185	2,199
Total contractual cash obligations	$ 8,542	$ 9,930	$ 11,796	$ 63,504	$ 93,772

(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. Additionally, refer to Note 16 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

BHE's regulated subsidiaries and certain affiliates are subject to comprehensive regulation. In addition to the discussion contained herein regarding regulatory matters, refer to Item 1 of this Form 10-K for further discussion regarding the general regulatory framework at BHE's regulated subsidiaries.

PacifiCorp

Utah Mine Disposition

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

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

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

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

The asset sales and coal supply agreements are contingent upon regulatory approvals, which PacifiCorp has requested be issued no later than May 27, 2015 in order to close the transactions with the third party by May 31, 2015. For additional information related to the accounting impacts associated with the Utah Mine Disposition, refer to Note 6 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K.

Utah

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

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

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

Oregon

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

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

Wyoming

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

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

Washington

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

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

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

Idaho

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

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

MidAmerican Energy

In July 2014, the IUB issued an order approving new retail electric base rates for MidAmerican Energy's Iowa customers. The order allows MidAmerican Energy to increase its base rates over approximately three years and will result in 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 approves the implementation of two new adjustment clauses. One clause relates to retail energy production costs such as fuel, fuel transportation and the impacts of the production tax credit. The second clause relates to certain electric transmission charges. The adjustment clauses provide for recovery of these costs from customers based on MidAmerican Energy's forecasted annual costs, with the variance between actual and forecasted costs to be recovered or credited in the following year. The order also approves seasonal pricing that results in a greater difference between higher base rates in effect for June through September and base rates applicable to the remaining months of the year, which MidAmerican Energy expects will shift an additional 15-25% of annual earnings into the June through September period. Additionally, the order approves 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%. The customer portion of any sharing reduces rate base. The changes in seasonal pricing, adjustment clauses and new revenue sharing mechanism were effective with final base rates. MidAmerican Energy and the Iowa Office of Consumer Advocate 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%.

In November 2014, the Illinois Commerce Commission ("ICC") issued an order approving a retail electric base rate increase for MidAmerican Energy's Illinois customers. The order authorizes MidAmerican Energy to increase rates by $16 million, or 10%, annually and to implement a new adjustment clause for the recovery of certain electric transmission charges. New rates and the adjustment clause were effective in December 2014.

NV Energy

The PUCN's final order approving the merger between BHE and NV Energy stipulated that NV Energy will not seek recovery of any lost revenue for calendar year 2014 in an amount that exceeds 50% of the lost revenue that NV Energy could otherwise request. In February 2014, NV Energy filed an application with the PUCN to reset the EEIR and energy efficiency program rates. 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 NV Energy would otherwise be allowed to recover for the 2014 calendar year. The EEIR was effective from July through December 2014 and will reset on January 1, 2015 and remain in effect through September 2015. To the extent the NV Energy earned rate of return exceeds the rate of return used to set base general rates, NV Energy is required to refund to customers EEIR revenue collected. As a result, NV Energy has deferred recognition of EEIR revenue collected and has recorded a liability of $13 million on the Consolidated Balance Sheets as of December 31, 2014.

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. 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.

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.

Emissions Reduction and Capacity Replacement Plan

In May 2014, Nevada Power filed its Emissions Reduction Capacity Replacement Plan ("ERCR Plan") in compliance with Senate Bill No. 123 ("SB 123") enacted by the 2013 Nevada Legislature. 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. 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.

Kern River

In December 2009, the FERC issued an order establishing revised rates for the period of 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"). In November 2010, the FERC issued an order that established Kern River is entitled to base its Period Two rates on a 100% equity capital structure.

In July 2011, the FERC issued an order requiring, among other things, that Period Two rates be based on a return on equity of 11.55% and a levelization period that coincides with a contract length of 10 or 15 years. Kern River filed in compliance with the FERC's order in August 2011 and, following an order on compliance, again in September 2011. In late September 2011, the FERC issued a second order on compliance, accepting Kern River's filing. In February 2013, the FERC issued an order that denied the requests for rehearing regarding its previous orders on Period Two rates.

In December 2013, Kern River filed its notice of appeal with the United States Court of Appeals for the District of Columbia. Kern River appealed the effective date of the final order for purposes of refunds and the denial of allowing a modification to Period One rates related to the rolled in shipper group rate credit. The shipper group has appealed the appropriate rate of return to be utilized in designing Period Two rates in conjunction with the use of a 100% equity capital structure. Oral argument was held in February 2015 and a ruling is expected in the second quarter of 2015.

ALP

In July 2012, ALP filed a general tariff application requesting approval from the AUC for revenue requirements of C$492 million for 2013 and C$636 million for 2014, primarily due to continued investment in capital projects as directed by the AESO. In November 2013, the AUC issued its decision approving the majority of ALP's requested revenue requirement. In January 2014, ALP submitted a compliance filing as directed by the AUC, requesting approval of a revenue requirement of C$481 million for 2013 and C$621 million for 2014. In September 2014, the AUC issued its decision approving ALP's January 2014 compliance filing as filed.

In its November 2013 decision pertaining to ALP's 2013-2014 general tariff application, the AUC directed AltaLink to re-forecast the capital project expenditures for 2013 and 2014 EPCM services to reflect a two times labor multiplier and other approved mark-ups. ALP has appealed this decision, which is scheduled to be heard in April 2015. ALP has requested approval of the capital project expenditures, including the new competitively bid EPCM rates, in its latest direct assigned capital deferral account filing.

In November 2014, ALP filed a general tariff application 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 January 2015, the AUC issued its decision approving ALP's 2015 interim tariff application, as filed, thereby authorizing ALP to invoice the AESO C$61 million per month commencing January 1, 2015.

In November 2011, the AUC approved credit metric relief for ALP's 2011 and 2012 transmission tariffs in the form of (i) the continuation of the future income tax method for federal income taxes and (ii) the use of CWIP in rate base. In its November 2013 decision pertaining to ALP's 2013-2014 general tariff application, the AUC approved the continuation of the existing credit metric relief for 2013 and 2014, and provided additional relief in the form of approving the use of the future income tax method for calculating the recovery associated with provincial income taxes. In ALP's 2015-2016 general tariff application, ALP has proposed to the AUC to discontinue CWIP in rate base accounting beginning in 2015, which would reduce customer bills by C$115 million over the two-year test period in 2015 and 2016. In its future decisions regarding ALP's general tariff applications, the AUC may accept the proposal regarding ongoing credit rating support measures or direct ALP to refile its application to include or remove various forms of credit rating support, which may significantly increase or decrease ALP's final tariffs for the test years.

In December 2013, the AUC directed AltaLink to use a placeholder rate of return on common equity of 8.75% for 2013 and each subsequent year thereafter, pending a final decision on its ongoing generic cost of capital proceeding, for which the AUC has completed its oral hearing and received arguments and supplemental arguments from all parties. ALP expects the AUC to issue a decision regarding the ongoing generic cost of capital proceeding in the first half of 2015.

BHE U.S. Transmission

In January 2014, ETT filed its first ITCOS of 2014 at the PUCT. The application was based on a test year ended November 30, 2013. The filing requested an increase in total transmission invested capital of $433 million and a total revenue requirement increase of $59 million. In February 2014, the administrative law judge signed the final order making the new rates effective. This increase placed total annual revenue requirements at $294 million and a rate base of $2.1 billion.

In July 2014, ETT filed its second ITCOS of 2014 at the PUCT. The application was based on a test year ended June 30, 2014. The filing requested an increase in total transmission invested capital of $12 million and a total revenue requirement increase of $2 million. In September 2014, the administrative law judge signed the final order making the new rates effective. This increase placed the total annual revenue requirements at $296 million and a rate base of $2.1 billion.

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 the Company'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. The Company believes it is in material compliance with all applicable laws and regulations, although many are subject to interpretation that may ultimately be resolved by the courts. Refer to "Liquidity and Capital Resources" for discussion of the Company's forecasted environmental-related capital expenditures.

Clean Air Act Regulations

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

National Ambient Air Quality Standards

Under the authority of the Clean Air Act, the EPA sets minimum national ambient air quality standards for six principal pollutants, consisting of carbon monoxide, lead, nitrogen oxides, particulate matter, ozone and sulfur dioxide, considered harmful to public health and the environment. Areas that achieve the standards, as determined by ambient air quality monitoring, are characterized as being in attainment, while those that fail to meet the standards are designated as being nonattainment areas. Generally, sources of emissions in a nonattainment area that are determined to contribute to the nonattainment are required to reduce emissions. Most air quality standards require measurement over a defined period of time to determine the average concentration of the pollutant present. Currently, with the exceptions described in the following paragraphs, air quality monitoring data indicates that all counties where the Company's major emission sources are located are in attainment of the current national ambient air quality standards.

In December 2009, the EPA designated the Utah counties of Davis and Salt Lake, as well as portions of Box Elder, Cache, Tooele, Utah and Weber counties, to be in nonattainment of the fine particulate matter standard. While this designation has the potential to impact PacifiCorp's Lake Side and Gadsby generating facilities, the Utah fine particulate matter SIP, as submitted to the EPA, did not impose significant new requirements on PacifiCorp's impacted generating facilities, nor did the EPA's comments on the Utah SIP identify requirements for PacifiCorp's existing generating facilities that would have a material impact on the Company's consolidated financial results.

In November 2014, the EPA released a new proposal to strengthen the national ambient air quality standard for ground level ozone from the current level of 75 parts per billion to a level between 65 and 70 parts per billion. Review or revision is required to be complete by October 2015. Until the standards' review or revision is complete, the EPA is proceeding with implementation of the 2008 ozone standards. The Upper Green River Basin Area in Wyoming, including all of Sublette and portions of Lincoln and Sweetwater Counties, were proposed to be designated as nonattainment for the 2008 ozone standard. When the final designations were released in April 2012, portions of Lincoln and Sweetwater Counties and Sublette County were determined to be in marginal nonattainment. While PacifiCorp's Jim Bridger plant is located in Sweetwater County, it is not in the portion of the designated nonattainment area and has not been impacted by the 2012 designation. In 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, Goodsprings and Reid Gardner generating facilities. However, until such time as a new standard is implemented or Clark County is classified as nonattainment for the 2008 standard, 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.

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

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

Mercury and Air Toxics Standards

In March 2011, the EPA proposed a rule that requires coal-fueled generating facilities to reduce mercury emissions and other hazardous air pollutants through the establishment of "Maximum Achievable Control Technology" standards. The final rule, MATS, was published in the Federal Register in February 2012, with an effective date of April 16, 2012, and requires that new and existing coal-fueled generating facilities achieve emission standards for mercury, acid gases and other non-mercury hazardous air pollutants. Existing sources are required to comply with the new standards by April 16, 2015. Individual sources may be granted up to one additional year, at the discretion of the Title V permitting authority, to complete installation of controls or for transmission system reliability reasons. The Company believes that its emissions reduction projects completed to date or currently permitted or planned for installation, including scrubbers, baghouses and electrostatic precipitators, are consistent with the EPA's MATS and will support the Company's ability to comply with the final rule's standards for acid gases and non-mercury metallic hazardous air pollutants. The Company is proceeding with additional actions to reduce mercury emissions through the installation of controls and use of sorbent injection at certain of its coal-fueled generating facilities to otherwise comply with the final rule's standards.

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

MidAmerican Energy plans to retire four coal-fueled generating units between 2015 and 2016 as the least-cost alternative to comply with the MATS. Walter Scott, Jr. Energy Center Units 1 and 2 are to be retired by April 15, 2015, and George Neal Energy Center Units 1 and 2 are to be retired by April 15, 2016. These units produced 2.1 million MWh of electricity, or 7% of MidAmerican Energy's owned generation production, during 2014. A fifth unit, Riverside Generating Station, will be limited to natural gas combustion by March 31, 2015.

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

Clean Air Interstate Rule, Clean Air Transport Rule and Cross-State Air Pollution Rule

The EPA promulgated the CAIR in March 2005 to reduce emissions of nitrogen oxides and sulfur dioxide, precursors of ozone and particulate matter, from down-wind sources. The CAIR required states 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. The CAIR created separate trading programs for nitrogen oxides and sulfur dioxide emissions credits. The nitrogen oxides and sulfur dioxide emissions reductions were planned to be accomplished in two phases, in 2009-2010 and 2015. After the CAIR was overturned by the D.C. Circuit in 2008, the EPA proposed a successor rule, which became known as the Cross-State Air Pollution Rule ("CSAPR"), to address interstate transport of sulfur dioxide and nitrogen oxides emissions in 27 eastern and Midwestern states. Upon full implementation in 2014, the CSAPR would have reduced total sulfur dioxide emissions by 73% and nitrogen oxides emissions by 54% at electric generating facilities in the 27-state region as compared to 2005 levels.

After additional litigation over the rule, the United States Supreme Court issued a decision on April 29, 2014, upholding the 2011 CSAPR, concluding that the EPA's allocation of emissions reductions in upwind states permissibly considered the cost-effectiveness of achieving downwind attainment and that the EPA had authority under the Clean Air Act to impose federal implementation plans immediately after disapproving state implementation plans. The United States Supreme Court remanded the case to the D.C. Circuit for further action. The D.C. Circuit's previous stay of the rule was lifted in October 2014 and the first phase of the rule was implemented January 1, 2015.

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 final rule.

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 the Company. 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 and Arizona 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. Oral argument was held before the Tenth Circuit in March 2014. In May 2014, the Tenth Circuit dismissed the petition on jurisdictional grounds. In addition, and separate from the EPA's approval process and related litigation, the Utah Division of Air Quality has undertaken an additional BART analysis for Hunter Units 1 and 2, and Huntington Units 1 and 2, for which the public comment period closed in December 2014. The additional analysis will be provided to the EPA as a supplement to the existing Utah SIP once the Utah Division of Air Quality responds to the public comments. It is unknown whether and how this supplemental analysis will impact the EPA's decision regarding the Utah SIP.

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

The state of Arizona issued a regional haze SIP requiring, among other things, the installation of sulfur dioxide, nitrogen oxides and particulate matter controls on Cholla Unit 4. The EPA approved in part, and disapproved in part, the Arizona SIP and issued a FIP for the disapproved portions requiring SCR controls on Cholla Unit 4. PacifiCorp filed an appeal in the United States Court of Appeals for the Ninth Circuit ("Ninth Circuit") regarding the FIP as it relates to Cholla Unit 4, and the Arizona Department of Environmental Quality and other affected Arizona utilities filed separate appeals of the FIP as it relates to their interests. The Ninth Circuit issued an order on February 20, 2015, holding the matter in abeyance relating to PacifiCorp and Arizona Public Service Company as they work with state and federal agencies on an alternate compliance approach for Cholla Unit 4. In January 2015, Arizona Public Service Company submitted the permit applications and studies required to amend the Title V permit, and subsequently the Arizona SIP to convert Cholla Unit 4 to a natural gas-fueled unit in 2025. The amended plan is currently awaiting review and approval by the state of Arizona and after approval will be submitted to the EPA for review and approval.

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

Environmental groups have challenged both of the EPA's final determinations with respect to Nevada's regional haze SIP. In May 2012, WildEarth Guardians petitioned the Ninth Circuit to review the EPA's March 2012 approval of Nevada's SIP for all affected units and emissions except nitrogen oxides controls at the Reid Gardner Generating Station. Both Nevada Power and Sierra Pacific intervened in the lawsuit and briefing was completed in February 2013.The matter was heard before the Ninth Circuit in May 2014. On July 17, 2014, the Ninth Circuit issued its decision, dismissing the petition in part because WildEarth Guardians did not have standing to challenge a portion of the SIP, and denying the petition in part based on its conclusion that the EPA's approval of the Nevada SIP was appropriate.

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 July 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 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. 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, the Company 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.

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

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

New Source Review

Under existing New Source Review ("NSR") provisions of the Clean Air Act, any facility that emits regulated pollutants is required to obtain a permit from the EPA or a state regulatory agency prior to (a) beginning construction of a new major stationary source of a regulated pollutant or (b) making a physical or operational change to an existing stationary source of such pollutants that increases certain levels of emissions, unless the changes are exempt under the regulations (including routine maintenance, repair and replacement of equipment). In general, projects subject to NSR regulations require pre-construction review and permitting under the Prevention of Significant Deterioration ("PSD") provisions of the Clean Air Act. Under the PSD program, a project that emits threshold levels of regulated pollutants must undergo an analysis to determine the best available control technology and evaluate the most effective emissions controls after consideration of a number of factors. Violations of NSR regulations, which may be alleged by the EPA, states, environmental groups and others, potentially subject a company to material fines and other sanctions and remedies, including installation of enhanced pollution controls and funding of supplemental environmental projects.

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

As part of an industry-wide investigation to assess compliance with the NSR and PSD provisions, the EPA has requested information and supporting documentation from numerous utilities regarding their capital projects for various coal-fueled generating facilities. A NSR enforcement case against an unrelated utility has been decided by the United States Supreme Court, holding that an increase in the annual emissions of a generating facility, when combined with a modification (i.e., a physical or operational change), may trigger NSR permitting. Between 2001 and 2003, PacifiCorp and MidAmerican Energy responded to requests for information relating to their capital projects at their coal-fueled generating facilities. PacifiCorp engaged in periodic discussions with the EPA over several years regarding PacifiCorp's historical projects and their compliance with NSR and PSD provisions. In September 2011, PacifiCorp received a letter from the EPA concluding these discussions. In September 2013, PacifiCorp received a Section 114 request for information for certain projects and facilities in Wyoming and Utah. PacifiCorp provided timely responses to the request. PacifiCorp cannot predict the next steps in this process and could be required to install additional emissions controls and incur additional costs and penalties in the event it is determined that PacifiCorp's historical projects did not meet all regulatory requirements.

In October 2011, MidAmerican Energy received a request from the EPA Region 7 pursuant to Section 114 of the Clean Air Act for information on its coal-fueled generating facilities to supplement the requests made in 2002 and 2003. MidAmerican Energy submitted its response to the October 2011 request in December 2011. MidAmerican Energy cannot predict the outcome of this matter at this time.

In June 2009, Sierra Pacific received a request from the EPA Region 9 pursuant to Section 114 of the Clean Air Act for information regarding current and historic operations and capital project information for Sierra Pacific's Valmy Generating Station. Sierra Pacific operates and owns 50% of the Valmy coal-fueled generating facility. Sierra Pacific submitted its response to the EPA in December 2009. Sierra Pacific cannot predict the outcome of this matter at this time.

In October 2011, Nevada Power received a request from the EPA Region 9 pursuant to Section 114 of the Clean Air Act for information regarding current and historic operations and capital projects for Nevada Power's Reid Gardner coal-fueled generating facility. Nevada Power submitted its response to the EPA during the first quarter of 2012. Nevada Power cannot predict the outcome of this matter at this time.

Climate Change

While significant measures to regulate GHG emissions at the federal level were considered by the United States Congress in 2010, comprehensive climate change legislation has not been adopted. In June 2013, President Obama issued a Climate Action Plan, which, among other things, required the EPA to address GHG emissions from new, modified and existing fossil-fueled generating facilities under the Clean Air Act. Regulation of GHG emissions has proceeded under various provisions of the Clean Air Act since the EPA's December 2009 findings that GHG emissions threaten public health and welfare.

GHG Tailoring Rule

In May 2010, the EPA finalized the GHG "Tailoring Rule" requiring new or modified sources of GHG emissions with increases of 75,000 or more tons per year of total GHG to determine the best available control technology for their GHG emissions beginning in January 2011. New or existing major sources are also subject to Title V operating permit requirements for GHG. Beginning July 1, 2011 through June 30, 2013, new construction projects that emit GHG emissions of at least 100,000 tons per year and modifications of existing facilities that increase GHG emissions by at least 75,000 tons per year became subject to permitting requirements. While the final rule also required facilities that were previously not subject to Title V permitting requirements to obtain Title V permits if they emit at least 100,000 tons per year of carbon dioxide equivalents, litigation over the Tailoring Rule resulted in a decision by the United States Supreme Court in June 2014 that the EPA could not utilize the Tailoring Rule to impose GHG permitting requirements on sources not otherwise subject to Clean Air Act permitting provisions. That decision did not impact the Company’s sources that are already subject to Clean Air Act permitting. MidAmerican Energy has obtained permits to install emissions reduction equipment at existing generating facilities to comply with the transport rule (previously referenced as CSAPR and in its current implementation of the CAIR requirements) and was required to assess the impacts of the projects on GHG emissions. A GHG emissions limit was imposed on the permits for those projects. PacifiCorp's permitting of certain existing generating facilities to install emissions reduction equipment to comply with the Regional Haze Rules assessed the impacts of the projects on GHG emissions under the GHG Tailoring Rule. No GHG emissions limit was included in the permits. However, PacifiCorp's Lake Side 2 was subject to a best available control technology review and the permit includes a limit for carbon dioxide equivalent emissions. Both MidAmerican Energy's and PacifiCorp's management believe compliance with the GHG limits under these permits will not result in a material adverse impact on its operations. To date, permitting authorities implementing the GHG Tailoring Rule have included efficiency improvements to demonstrate compliance with best available control technology for GHG, as well as requiring emissions limits for GHGs in permits, which have not had a material impact on the Company's consolidated financial results.

GHG Performance Standards

Under the Clean Air Act, the EPA may establish emissions standards that reflect the degree of emissions reductions achievable through the best technology that has been demonstrated, taking into consideration the cost of achieving those reductions and any non-air quality health and environmental impact and energy requirements. The EPA entered into a settlement agreement with a number of parties, including certain state governments and environmental groups, in December 2010 to promulgate emissions standards covering GHG. In April 2012, the EPA proposed new source performance standards for new fossil-fueled generating facilities that would limit emissions of carbon dioxide to 1,000 pounds per MWh. As part of his Climate Action Plan, President Obama announced a national climate change strategy and issued a presidential memorandum requiring the EPA to issue a re-proposed GHG new source performance standard for fossil-fueled generating facilities by September 2013. The September 2013 GHG new source performance standards released by the EPA set different standards for coal-fueled and natural gas-fueled generating facilities. The proposed standard for natural gas-fueled generating facilities considers the size of the unit and the electricity sent to the grid from the unit, establishing a standard of 1,000 to 1,100 pounds of carbon dioxide per MWh. The standard proposed for coal-fueled generating facilities is 1,100 pounds of carbon dioxide per MWh on an annual basis or 1,000 to 1,050 pounds of carbon dioxide per MWh averaged over a seven-year period, both of which would require partial carbon capture and sequestration. The proposed standards were published in the Federal Register January 8, 2014, and the public comment period closed in May 2014. Any new fossil-fueled generating facilities constructed by the Company will be required to meet the GHG new source performance standards, which are expected to be finalized in the summer of 2015.

In June 2014, the EPA released proposed regulations to address GHG emissions from existing fossil-fueled generating facilities, referred to as the Clean Power Plan, under Section 111(d) of the Clean Air Act. The EPA's proposal calculated state-specific emission rate targets to be achieved based on four building blocks that it determined were the "Best System of Emission Reduction." The four building blocks include: (a) a 6% heat rate improvement from coal-fueled generating facilities; (b) increased utilization of existing combined-cycle natural gas-fueled generating facilities to 70%; (c) increased deployment of renewable and non-carbon generating resources; and (d) increased energy efficiency. Under the EPA's proposal, states may utilize any measure to achieve the specified emission reduction goals, with an initial implementation period of 2020-2029 and the final goal to be achieved by 2030. When fully implemented, the proposal is expected to reduce carbon dioxide emissions in the power sector to 30% below 2005 levels by 2030. The public comment period closed December 1, 2014 and the final guidelines are scheduled to be issued in the summer of 2015. States are required to submit implementation plans by June 2016, but they may request an extension to June 2017, or June 2018 if they plan to participate in a regional compliance program. The impacts of the proposal on PacifiCorp, MidAmerican Energy, Nevada Power, Sierra Pacific and BHE Renewables cannot be determined until the EPA finalizes the proposal and the states develop their implementation plans. 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 November 2014, President Obama announced the United States and China had reached a climate change agreement under which the United States intends to achieve an economy-wide target of reducing its emissions by 26% to 28% below 2005 levels in 2025 and China would peak its GHG emissions around 2030 and increase the share of non-fossil fuels in primary energy consumption to 20% by 2030.

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

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

- MidAmerican Energy owns the largest and PacifiCorp owns the second largest portfolio of wind-powered generating capacity in the United States among rate-regulated utilities. As of December 31, 2014, the Company had 5,168 MW of wind-powered generating capacity in operation and under construction at a total cost when constructed of over $9 billion.
- As of December 31, 2014, the Company owned 1,286 MW of solar generating capacity in operation and under construction at a total cost when constructed of approximately $6 billion. As of December 31, 2014, 1,092 MW of solar generating capacity was in-service.
- PacifiCorp owns 1,145 MW of hydroelectric generating capacity.
- Investments in transmission systems that: (a) address customer load growth; (b) improve system reliability; (c) reduce transmission system constraints; (d) provide access to diverse generation resources, including renewable resources; and (e) improve the flow of electricity.
- The Utilities have offered customers a comprehensive set of DSM programs for more than 20 years. The programs assist customers to manage the timing of their usage, as well as to reduce overall energy consumption, resulting in lower utility bills.

New federal, regional, state and international accords, legislation, regulation, or judicial proceedings limiting GHG emissions could have a material adverse impact on the Company, 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 Company 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 Company'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 Company's existing and future electricity generating portfolio. These issues may have a direct impact on the costs of electricity production and increase the price customers pay or their demand for electricity.

Regional and State Activities

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

- Under the authority of California's Global Warming Solutions Act signed into law in 2006, the California Air Resources Board adopted a GHG cap-and-trade program with an effective date of January 1, 2012; compliance obligations were imposed on entities beginning in 2013. The program purports to impose compliance obligations on entities, including PacifiCorp, that deliver wholesale energy to points that are outside of California, irrespective of retail service obligations. These obligations and other impacts to wholesale energy market structures may, if implemented as written, increase costs to PacifiCorp. In addition, California law imposes a GHG emissions performance standard to all electricity generated within the state or delivered from outside the state that is no higher than the GHG emissions levels of a state-of-the-art combined-cycle natural gas-fueled generating facility, as well as legislation that adopts an economy-wide cap on GHG emissions to 1990 levels by 2020. The first auction of GHG allowances was held in California in November 2012 with ongoing quarterly auctions.
- The states of California, Washington and Oregon have adopted GHG emissions performance standards for base load electricity generating resources. Under the laws in California and Oregon, the emissions performance standards provide that emissions must not exceed 1,100 pounds of carbon dioxide per MWh. Effective April 2013, Washington's amended emissions performance standards provide that GHG emissions for base load electricity generating resources must not exceed 970 pounds of carbon dioxide per MWh. These GHG emissions performance standards generally prohibit electric utilities from entering into long-term financial commitments (e.g., new ownership investments, upgrades, or new or renewed contracts with a term of five or more years) unless any base load generation supplied under long-term financial commitments comply with the GHG emissions performance standards.
- Washington and Oregon enacted legislation in May 2007 and August 2007, respectively, establishing goals for the reduction of GHG emissions in their respective states. Washington's goals seek to (a) reduce emissions to 1990 levels by 2020; (b) reduce emissions to 25% below 1990 levels by 2035; and (c) reduce emissions to 50% below 1990 levels by 2050, or 70% below Washington's forecasted emissions in 2050. Oregon's goals seek to (a) cease the growth of Oregon GHG emissions by 2010; (b) reduce GHG levels to 10% below 1990 levels by 2020; and (c) reduce GHG levels to at least 75% below 1990 levels by 2050. Each state's legislation also calls for state government to develop policy recommendations in the future to assist in the monitoring and achievement of these goals.
- 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. In February 2013, the Regional Greenhouse Gas Initiative states proposed to lower the previously established emission cap and to identify a policy on emissions associated with imported electricity.

GHG Litigation

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

Renewable Portfolio Standards

Each state's RPS described below could significantly impact the Company'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 Company can be subject to penalties in the event of noncompliance. The Company believes it is in material compliance with all applicable RPS laws and regulations.

Washington's Energy Independence Act establishes a renewable energy target for qualifying electric utilities, including PacifiCorp. The requirements are 3% of retail sales by January 1, 2012 through 2015, 9% of retail sales by January 1, 2016 through 2019 and 15% of retail sales by January 1, 2020 and each year thereafter. In April 2013, Washington State Senate Bill No. 5400 ("SB 5400") was signed into law. SB 5400 expands the geographic area in which eligible renewable resources may be located to beyond the Pacific Northwest, allowing renewable resources located in all states served by PacifiCorp to qualify. SB 5400 also provides PacifiCorp with additional flexibility and options to meet Washington's renewable mandates.

The Oregon Renewable Energy Act ("OREA") provides a comprehensive renewable energy policy and RPS for Oregon. Subject to certain exemptions and cost limitations established in the law, PacifiCorp and other qualifying electric utilities must meet minimum qualifying electricity requirements for electricity sold to retail customers of at least 5% in 2011 through 2014, 15% in 2015 through 2019, 20% in 2020 through 2024, and 25% in 2025 and subsequent years. As required by the OREA, the OPUC has approved an automatic adjustment clause to allow an electric utility, including PacifiCorp, to recover prudently incurred costs of its investments in renewable energy generating facilities and associated transmission costs.

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

Utah's Energy Resource and Carbon Emission Reduction Initiative provides that, beginning in the year 2025, 20% of adjusted retail electric sales of all Utah utilities be supplied by renewable energy, if it is cost effective. Retail electric sales will be adjusted by deducting the amount of generation from sources that produce zero or reduced carbon emissions, and for sales avoided as a result of energy efficiency and DSM programs. Qualifying renewable energy sources can be located anywhere in the WECC areas, and renewable energy credits can be used.

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. The Nevada Utilities are in compliance with these requirements.

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, Carbon and Huntington generating facilities currently utilize closed cycle cooling towers but are designed to withdraw more than two million gallons of water per day. The standards are required to be met as soon as possible after the effective date of the final rule, but no later than eight years thereafter. The costs of compliance with the cooling water intake structure rule cannot be fully determined until the prescribed studies are conducted. In the event that PacifiCorp's 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 expected to be impacted by the §316(b) final rule.

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

In April 2014, the EPA and the United States Army Corps of Engineers issued a joint proposal to address "Waters of the United States" to clarify protection under the Clean Water Act for streams and wetlands. The proposed rule comes as a result of United States Supreme Court decisions in 2001 and 2006 that created confusion regarding jurisdictional waters that were subject to permitting under either nationwide or individual permitting requirements. As currently proposed, a variety of projects that otherwise would have qualified for streamlined permitting processes under nationwide or regional general permits will be required to undergo more lengthy and costly individual permit procedures based on an extension of waters that will be deemed jurisdictional. The public comment period closed November 14, 2014. Until the rule is finalized, the Company 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 and will be effective 180 days after it is published in the Federal Register. The final rule regulates coal combustion byproducts as non-hazardous waste under RCRA Subtitle D and establishes minimum nationwide standards for the disposal of coal combustion residuals. Under the final rule, surface impoundments and landfills utilized for coal combustion byproducts may need to be closed unless they can meet the more stringent regulatory requirements.

As defined by the final rule, PacifiCorp operates 18 surface impoundments and seven landfills that contain coal combustion byproducts. MidAmerican Energy owns or operates seven surface impoundments and four landfills that contain coal combustion byproducts. The Nevada Utilities operates ten evaporative surface impoundments that are likely to fall within the definition of the final rule and two landfills that contain coal combustion byproducts. The Company is assessing the requirements of the final rule to determine the costs of compliance.

Other

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

- The federal Comprehensive Environmental Response, Compensation and Liability Act and similar state laws may require any current or former owners or operators of a disposal site, as well as transporters or generators of hazardous substances sent to such disposal site, to share in environmental remediation costs.
- The 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 Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for additional information regarding 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 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 Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for information regarding the relicensing of PacifiCorp's Klamath River hydroelectric system.

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

Collateral and Contingent Features

Debt 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, 2014, 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, 2014, the Company would have been required to post $556 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 the Company's derivative contracts and Note 16 of Notes to Consolidated Financial Statements in Item 8 of this Form 10-K for a discussion of the Company's collateral requirements specific to the Company's equity commitments.

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.

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, 2014, the Company's investments that are accounted for under the equity method had short- and long-term debt of $2.4 billion, unused revolving credit facilities of $435 million and letters of credit outstanding of $88 million. As of December 31, 2014, the Company's pro-rata share of such short- and long-term debt was $1.1 billion, unused revolving credit facilities was $186 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 written off to 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 $2.8 billion as of December 31, 2014. 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. MidAmerican Energy 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. Each of the Company's business platforms 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. 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, 2014, the Company had a net derivative liability of $248 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 critical because any changes in assumptions could have a significant impact on the estimated fair value of the contracts. As of December 31, 2014, 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, 2014, the Company had $223 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, 2014 includes goodwill of acquired businesses of $9.3 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, 2014. 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 22 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, 2014, 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

The Company sponsors defined benefit pension and other postretirement benefit plans that cover the majority of its employees. The Company recognizes the funded status of its defined benefit pension and other postretirement benefit plans on the Consolidated Balance Sheets. Funded status is the fair value of plan assets minus the benefit obligation as of the measurement date. As of December 31, 2014, the Company recognized a net liability totaling $390 million for the funded status of the Company's defined benefit pension and other postretirement benefit plans. As of December 31, 2014, amounts not yet recognized as a component of net periodic benefit cost that were included in net regulatory assets totaled $727 million and in AOCI totaled $674 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 Company's defined benefit pension and other postretirement benefit plans, including the key assumptions used to calculate the funded status and net periodic benefit cost for these plans as of and for the year ended December 31, 2014.

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 (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, 2014						
Benefit Obligations:						
Discount rate	$ (163)	$ 180	$ (37)	$ 38	$ (184)	$ 210
Effect on 2014 Periodic Cost:						
Discount rate	$ (6)	$ 7	$ (3)	$ 4	$ (15)	$ 15
Expected rate of return on plan assets	(12)	12	(4)	4	(10)	10

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, 2014, these amounts were recognized as a regulatory asset of $1.4 billion and a regulatory liability of $24 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 $3.1 billion as of December 31, 2014. 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 principally in the United Kingdom. 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 cash without triggering incremental United States income tax expense, the Company may distribute certain foreign earnings of Northern Powergrid.

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 $666 million as of December 31, 2014. Factors that can impact the estimate of unbilled energy include, but are not limited to, seasonal weather patterns, total volumes supplied to the system, line losses, economic impacts and composition of sales among customer classes. Estimates are reversed in the following month and actual revenue is recorded based on subsequent meter readings.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

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. MidAmerican Energy 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 the 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 $75 million and $12 million as of December 31, 2014 and 2013, respectively, and shows the effects of a hypothetical 10% increase and 10% decrease in forward market prices 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, 2014:			
Not designated as hedging contracts	$ (156)	$ (120)	$ (191)
Designated as hedging contracts	(36)	9	(81)
Total commodity derivative contracts	$ (192)	$ (111)	$ (272)
As of December 31, 2013:			
Not designated as hedging contracts	$ (128)	$ (95)	$ (161)
Designated as hedging contracts	(12)	23	(47)
Total commodity derivative contracts	$ (140)	$ (72)	$ (208)

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, 2014 and 2013, a net regulatory asset of $223 million and $182 million, respectively, was recorded related to the net derivative liability of $156 million and $128 million, respectively. 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, 2014 and 2013, the Company had short- and long-term variable-rate obligations totaling $6.7 billion and $4.5 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, 2014 and 2013.

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, 2014 and 2013, the Company had variable-to-fixed interest rate swaps for the notional amount of $443 million and $650 million, respectively, to protect the Company against an increase in interest rates. Additionally, as of December 31, 2014 and 2013, the Company had mortgage sale commitments, net for the notional amount of $264 million and $121 million, respectively, to protect the Company against an increase in interest rates. As of December 31, 2014, the fair value of the Company's interest rate derivative contracts was a net derivative liability of $5 million and as of December 31, 2013 was a net derivative asset of $7 million. 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, 2014 and 2013, the Company's investment in BYD Company Limited common stock represented approximately 70% and 77%, 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 our investment in BYD Company Limited as of December 31, 2014 and 2013 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, 2014	$ 881	30% increase	$ 1,145	1%
		30% decrease	617	(1)
As of December 31, 2013	$ 1,103	30% increase	$ 1,434	1%
		30% decrease	772	(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, 2014, 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 $381 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 $41 million in 2014.

AltaLink's functional currency is the Canadian dollar. As of December 31, 2014, 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 $277 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 $1 million in 2014.

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. 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 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, 2014, PacifiCorp's aggregate credit exposure from wholesale activities totaled $214 million, based on settlement and mark-to-market exposures, net of collateral. As of December 31, 2014, $211 million, or 99%, of PacifiCorp's credit exposure was with counterparties having investment grade credit ratings by either Moody's Investor Service or Standard & Poor's Rating Services. As of December 31, 2014, two counterparties comprised $150 million, or 70%, of the aggregate credit exposure. The two counterparties are rated investment grade by Moody's Investor Service and Standard & Poor's Rating Services, and PacifiCorp is not aware of any factors that would likely result in a downgrade of the counterparties' credit ratings to below investment grade over the remaining term of transactions outstanding as of December 31, 2014.

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. As of December 31, 2014, MidAmerican Energy's aggregate direct credit exposure from electric wholesale marketing counterparties was not material.

As of December 31, 2014, NV Energy's aggregate credit exposure from energy related transactions totaled $37 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 electrical infrastructure to supply companies and generators connected to their networks. 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 25% of distribution revenue in 2014. 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 sole source of operating revenue is the AESO. 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 $62 million for the year ended December 31, 2014.

BHE Renewables

BHE Renewables source of operating revenue is derived primarily from long-term power purchase agreements with single customers from its independent power projects in the United States and the Philippines, which expire between 2016 and 2040. Because of the dependence on single customers at each project, any material failure of the customer to fulfill its obligations would significantly impair BHE Renewables' ability to meet its existing and future obligations. Total operating revenue for BHE Renewables was $623 million for the year ended December 31, 2014.

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, 2014 and 2013, 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, 2014. 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, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America. 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 27, 2015

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

	As of December 31,	
	2014	**2013**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 617	$ 1,175
Trade receivables, net	1,837	1,769
Income taxes receivable	1,156	44
Inventories	826	853
Other current assets	1,507	1,061
Total current assets	5,943	4,902
Property, plant and equipment, net	59,248	50,119
Goodwill	9,343	7,527
Regulatory assets	4,000	3,322
Investments and restricted cash and investments	2,803	3,236
Other assets	967	894
Total assets	$ 82,304	$ 70,000

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,	
	2014	**2013**
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 1,991	$ 1,636
Accrued interest	454	431
Accrued property, income and other taxes	366	362
Accrued employee expenses	255	228
Short-term debt	1,445	232
Current portion of long-term debt	1,232	1,188
Other current liabilities	1,369	887
Total current liabilities	7,112	4,964
Regulatory liabilities	2,669	2,498
BHE senior debt	7,860	6,366
BHE junior subordinated debentures	3,794	2,594
Subsidiary debt	25,763	21,864
Deferred income taxes	11,802	10,158
Other long-term liabilities	2,731	2,740
Total liabilities	61,731	51,184
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	6,423	6,390
Retained earnings	14,513	12,418
Accumulated other comprehensive loss, net	(494)	(97)
Total BHE shareholders' equity	20,442	18,711
Noncontrolling interests	131	105
Total equity	20,573	18,816
Total liabilities and equity	$ 82,304	$ 70,000

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,		
	2014	**2013**	**2012**
Operating revenue:			
Energy	$ 15,182	$ 10,826	$ 10,236
Real estate	2,144	1,809	1,312
Total operating revenue	17,326	12,635	11,548
Operating costs and expenses:			
Energy:			
Cost of sales	5,732	3,799	3,517
Operating expense	3,501	2,794	2,778
Depreciation and amortization	2,028	1,527	1,436
Real estate	2,019	1,680	1,250
Total operating costs and expenses	13,280	9,800	8,981
Operating income	4,046	2,835	2,567
Other income (expense):			
Interest expense	(1,711)	(1,222)	(1,176)
Capitalized interest	89	84	54
Allowance for equity funds	98	78	74
Other, net	80	66	56
Total other income (expense)	(1,444)	(994)	(992)
Income before income tax expense and equity income (loss)	2,602	1,841	1,575
Income tax expense	589	130	148
Equity income (loss)	109	(35)	68
Net income	2,122	1,676	1,495
Net income attributable to noncontrolling interests	27	40	23
Net income attributable to BHE shareholders	$ 2,095	$ 1,636	$ 1,472

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,		
	2014	**2013**	**2012**
Net income	$ 2,122	$ 1,676	$ 1,495
Other comprehensive (loss) income, net of tax:			
Unrecognized amounts on retirement benefits, net of tax of $19, $7 and $(28)	69	16	(84)
Foreign currency translation adjustment	(314)	74	135
Unrealized (losses) gains on available-for-sale securities, net of tax of $(84), $178 and $79	(134)	263	119
Unrealized (losses) gains on cash flow hedges, net of tax of $(13), $10 and $5	(18)	13	8
Total other comprehensive (loss) income, net of tax	(397)	366	178
Comprehensive income	1,725	2,042	1,673
Comprehensive income attributable to noncontrolling interests	27	40	23
Comprehensive income attributable to BHE shareholders	$ 1,698	$ 2,002	$ 1,650

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, 2011	75	$ —	$ 5,423	$ 9,310	$ (641)	$ 173	$ 14,265
Net income	—	—	—	1,472	—	22	1,494
Other comprehensive income	—	—	—	—	178	—	178
Distributions	—	—	—	—	—	(26)	(26)
Other equity transactions	—	—	—	—	—	(1)	(1)
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

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,		
	2014	**2013**	**2012**
Cash flows from operating activities:			
Net income	$ 2,122	$ 1,676	$ 1,495
Adjustments to reconcile net income to net cash flows from operating activities:			
Depreciation and amortization	2,057	1,560	1,455
Allowance for equity funds	(98)	(78)	(74)
Equity (income) loss	(109)	35	(68)
Changes in regulatory assets and liabilities	(168)	(6)	9
Deferred income taxes and amortization of investment tax credits	2,335	996	1,408
Other, net	177	37	62
Changes in other operating assets and liabilities, net of effects from acquisitions:			
Trade receivables and other assets	(44)	75	(122)
Derivative collateral, net	(70)	48	72
Pension and other postretirement benefit plans	86	(42)	(110)
Accrued property, income and other taxes	(1,117)	189	92
Accounts payable and other liabilities	(25)	179	108
Net cash flows from operating activities	5,146	4,669	4,327
Cash flows from investing activities:			
Capital expenditures	(6,555)	(4,307)	(3,380)
Acquisitions, net of cash acquired	(2,956)	(5,536)	(591)
Decrease (increase) in restricted cash and investments	173	(234)	(18)
Purchases of available-for-sale securities	(150)	(228)	(110)
Proceeds from sales of available-for-sale securities	118	191	88
Equity method investments	(37)	(93)	(363)
Other, net	(11)	13	53
Net cash flows from investing activities	(9,418)	(10,194)	(4,321)
Cash flows from financing activities:			
Proceeds from BHE senior debt	1,493	1,994	—
Proceeds from BHE junior subordinated debentures	1,500	2,594	—
Proceeds from issuance of BHE common stock	—	1,000	—
Repayments of BHE senior and subordinated debt	(550)	—	(772)
Proceeds from subsidiary debt	1,272	2,496	2,199
Repayments of subsidiary debt	(971)	(1,156)	(887)
Net proceeds from (repayments of) short-term debt	1,055	(849)	(6)
Other, net	(74)	(153)	(57)
Net cash flows from financing activities	3,725	5,926	477
Effect of exchange rate changes	(11)	(2)	7
Net change in cash and cash equivalents	(558)	399	490
Cash and cash equivalents at beginning of period	1,175	776	286
Cash and cash equivalents at end of period	$ 617	$ 1,175	$ 776

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 AltaLink Ltd. ("AltaLink") (which primarily consists of AltaLink, L.P. ("ALP")) and BHE U.S. Transmission, LLC (formerly MidAmerican Transmission, LLC)), BHE Renewables (formerly MidAmerican 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 the second largest residential real estate brokerage franchise network 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 AltaLink (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 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 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, 2014 and 2013, the allowance for doubtful accounts totaled $37 million and $33 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 $320 million and $407 million as of December 31, 2014 and 2013, respectively, and materials and supplies totaling $506 million and $446 million as of December 31, 2014 and 2013, 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 $41 million and $36 million higher as of December 31, 2014 and 2013, 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 2014 and 2012, 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, 2014 and 2013, unbilled revenue was $666 million and $686 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 Financing 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.

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, 2014 and 2013, these amounts were recognized as regulatory assets of $1.4 billion and $1.4 billion, respectively, and regulatory liabilities of $24 million and $34 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 $3.1 billion as of December 31, 2014. 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 principally in the United Kingdom. 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 cash without triggering incremental United States income tax expense, the Company may distribute certain foreign earnings of Northern Powergrid.

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 May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2014-09, which creates FASB Accounting Standards Codification ("ASC") Topic 606, "Revenue from Contracts with Customers" and supersedes ASC Topic 605, "Revenue Recognition." The guidance replaces industry-specific guidance and establishes a single five-step model to identify and recognize revenue. The core principle of the guidance is that an entity should recognize revenue upon transfer of control of promised goods or services to customers in an amount that reflects the consideration to which an entity expects to be entitled in exchange for those goods or services. Additionally, the guidance requires the entity to disclose further quantitative and qualitative information regarding the nature and amount of revenues arising from contracts with customers, as well as other information about the significant judgments and estimates used in recognizing revenues from contracts with customers. This guidance is effective for interim and annual reporting periods beginning after December 15, 2016. Early application is not permitted. This guidance may be adopted retrospectively or under a modified retrospective method where the cumulative effect is recognized at the date of initial application. 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". 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. This guidance should be adopted under a modified retrospective method where the cumulative effect is recognized at the date of initial application. The Company does not believe the adoption of this guidance will have a material impact on its Consolidated Financial Statements and disclosures included within Notes to Consolidated Financial Statements.

In February 2013, the FASB issued ASU No. 2013-04, which amends FASB ASC Topic 405, "Liabilities." The amendments in this guidance require an entity to measure obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date as the amount the reporting entity agreed to pay plus any additional amounts the reporting entity expects to pay on behalf of its co-obligor. Additionally, the guidance requires the entity to disclose the nature and amount of the obligation, as well as other information about those obligations. The Company adopted this guidance on January 1, 2014. The adoption of this guidance did not have a material impact on the Company's disclosures included within Notes to Consolidated Financial Statements.

(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 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. 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. ("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 7,800 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 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 Alberta Utilities Commission ("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 AltaLink 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 AltaLink'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. The fair value of certain contracts, deferred tax amounts and certain contingencies, among other items, are provisional and are subject to revision for up to 12 months following the acquisition date until the related valuations are completed. These items may be adjusted through regulatory assets or liabilities, to the extent recoverable in rates, or goodwill provided additional information is obtained about the facts and circumstances that existed as of the acquisition date. Such information includes, but is not limited to, further information regarding the fair value of the contracts and the resolution of contingency related items.

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	1,700
Other long-term assets	120
Total assets	7,604
Current liabilities, including current portion of long-term debt of $79	843
Subsidiary debt, less current portion	3,772
Deferred income taxes	79
Other long-term liabilities	182
Total liabilities	4,876
Net assets acquired	$ 2,728

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. The information is provisional in nature and subject to change based on final purchase accounting adjustments.

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.

The transaction was approved by the boards of directors of both NV Energy and BHE and the shareholders of NV Energy and received various regulatory approvals, including from the Public Utilities Commission of Nevada ("PUCN"), subject to certain stipulations. The stipulations included, among others:

- A one-time bill credit to retail customers of the Nevada Utilities totaling $20 million credited to retail customers over one billing cycle beginning within 30 days of the close of the NV Energy Transaction.
- BHE and NV Energy agreed to not seek recovery of the acquisition premium, transaction and transition costs associated with the NV Energy Transaction from customers.
- NV Energy agreed that it will base any rate case filed in 2014 with a requested change in revenue requirement on a return on common equity not to exceed 10%.
- The Nevada Utilities will not seek to collect lost revenues as described in section 704.9524 of the Nevada Administrative Code in 2014, and will not seek collection of lost revenues in excess of 50% of what the Nevada Utilities could otherwise request in 2015. NV Energy also agreed to work cooperatively with PUCN staff and the Nevada Bureau of Consumer Protection ("BCP") to develop a legislative or administrative alternative to the current mechanism that would retain the objective of encouraging investment in energy efficiency and that is acceptable to NV Energy, PUCN staff and the BCP. NV Energy and the BCP also agree to work in good faith to have a legislative or administrative alternative adopted.
- Normal rate case rules and procedures apply to costs and revenues, and any under or over earnings will accrue to the Nevada Utilities until the next rate case filing after 2014, subject to specified adjustments for intercompany charges from BHE and its other subsidiaries as described in the PUCN Joint Application and the exclusion of the $20 million one-time bill credit from the test period. The commitment does not preclude parties from proposing any other adjustments to test year or certification period results.

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, as a result of the PUCN stipulations discussed above, 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.

Allocation of Purchase Price

The operations of the Nevada Utilities are subject to the rate-setting authority of the PUCN and the FERC and are accounted for pursuant to GAAP, including the authoritative guidance for regulated operations. The rate-setting and cost recovery provisions establish retail rates on a cost-of-service basis designed to allow the Nevada Utilities an opportunity to recover their costs of providing service and a return on their investments in rate base. Except for regulatory assets not earning a return and certain assets not currently in rates, the fair value of the Nevada Utilities' 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 NV Energy'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.

NV Energy's non-regulated assets acquired and liabilities assumed consist principally of NV Energy's 6.25% senior notes due in 2020 and NV Energy’s variable-rate term loan that was paid in 2014. 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 $304	$ 1,159
Property, plant and equipment	9,511
Goodwill	2,369
Other long-term assets	1,347
Total assets	14,386
Current liabilities, including current portion of long-term debt of $218	880
Subsidiary debt, less current portion	5,116
Deferred income taxes	1,731
Other long-term liabilities	1,063
Total liabilities	8,790
Net assets acquired	$ 5,596

During 2014, the Company made revisions to regulatory assets not earning a return, certain assets not currently in rates and certain environmental and other 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 $2.4 billion and is reflected as goodwill in the NV Energy reportable segment. The goodwill reflects the value paid primarily for the long-term opportunity to improve operating results through the efficient management of operating expenses and the deployment of capital, as well as the opportunity to improve regulatory relationships and develop customer solutions to meet the long-term needs of the Nevada Utilities. 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, 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	2012
Operating revenue	$ 15,561	$ 14,369
Net income attributable to BHE shareholders	$ 1,867	$ 1,638

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 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.

In 2012, the Company completed various other acquisitions totaling $591 million. The purchase price for each acquisition was allocated to the assets acquired, which relate primarily to development and construction costs for the 550-megawatt ("MW") Topaz solar project ("Topaz Project"), the 81-MW Bishop Hill II wind-powered generation project ("Bishop Hill Project"), the 168-MW Pinyon Pines I and 132-MW Pinyon Pines II wind-generating facilities ("Pinyon Pines Projects") and the 309-MW Solar Star I and 270-MW Solar Star II solar projects ("Solar Star Projects"), and goodwill of $112 million and intangible franchise contracts of $92 million for a 66.7% interest in a real estate brokerage franchise business and five real estate brokerage businesses. The Company assumed long-term debt of $590 million and recognized a redeemable noncontrolling interest of $65 million. 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 a predetermined option exercise price. There were no other material liabilities assumed.

(4) Property, Plant and Equipment, Net

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

	Depreciable Life	2014	2013
Regulated assets:			
Utility generation, distribution and transmission system	5-80 years	$ 64,645	$ 57,490
Interstate pipeline assets	3-80 years	6,660	6,448
		71,305	63,938
Accumulated depreciation and amortization		(21,447)	(19,874)
Regulated assets, net		49,858	44,064
Nonregulated assets:			
Independent power plants	5-30 years	4,362	1,994
Other assets	3-30 years	673	522
		5,035	2,516
Accumulated depreciation and amortization		(839)	(678)
Nonregulated assets, net		4,196	1,838
Net operating assets		54,054	45,902
Construction work-in-progress		5,194	4,217
Property, plant and equipment, net		$ 59,248	$ 50,119

Construction work-in-progress includes $4.3 billion and $2.8 billion as of December 31, 2014 and 2013, respectively, related to the construction of regulated assets.

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

During the third quarter of 2012, MidAmerican Energy revised its depreciation rates for certain coal-fueled generation facilities reflecting shorter estimated useful lives. The effect of this change increased depreciation and amortization expense by $5 million in 2012 and $11 million annually based on depreciable plant balances at the time of the change. 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, 2014 (dollars in millions):

	Company Share	Facility In Service	Accumulated Depreciation and Amortization	Construction Work-in-Progress
PacifiCorp:				
Jim Bridger Nos. 1-4	67%	$ 1,134	$ 554	$ 116
Hunter No. 1	94	467	144	—
Hunter No. 2	60	290	88	1
Wyodak	80	450	183	5
Colstrip Nos. 3 and 4	10	231	125	1
Hermiston(1)	50	175	67	1
Craig Nos. 1 and 2	19	323	203	7
Hayden No. 1	25	55	27	12
Hayden No. 2	13	33	18	3
Foote Creek	79	37	22	—
Transmission and distribution facilities	Various	347	65	—
Total PacifiCorp		3,542	1,496	146
MidAmerican Energy:				
Louisa No. 1	88%	747	392	4
Quad Cities Nos. 1 and 2(2)	25	656	316	27
Walter Scott, Jr. No. 3	79	561	287	7
Walter Scott, Jr. No. 4(3)	60	446	82	3
George Neal No. 4	41	303	142	—
Ottumwa No. 1	52	530	171	2
George Neal No. 3	72	390	141	3
Transmission facilities	Various	243	81	17
Total MidAmerican Energy		3,876	1,612	63
NV Energy:				
Navajo	11%	198	135	2
Silverhawk	75	241	55	5
Valmy	50	343	213	27
Transmission facilities	Various	221	32	2
Total NV Energy		1,003	435	36
BHE Pipeline Group - common facilities	Various	311	175	2
Total		$ 8,732	$ 3,718	$ 247

(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 $320 million and $60 million, respectively.

(6) Regulatory Matters

Utah Mine Disposition

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

Regulatory Assets

Regulatory assets represent costs that are expected to be recovered in future 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	2014	2013
Deferred income taxes[(1)]	26 years	$ 1,468	$ 1,413
Employee benefit plans[(2)]	9 years	747	589
Asset disposition costs[(3)]	Various	329	23
Deferred net power costs	1 year	277	303
Asset retirement obligations	10 years	239	193
Unrealized loss on regulated derivative contracts	5 years	223	182
Abandoned projects	5 years	159	80
Unamortized contract values	8 years	123	146
Other	Various	688	586
Total regulatory assets		$ 4,253	$ 3,515
Reflected as:			
Current assets		$ 253	$ 193
Noncurrent assets		4,000	3,322
Total regulatory assets		$ 4,253	$ 3,515

(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 for the net property, plant and equipment not considered probable of disallowance and for the portion of losses associated with the assets held for sale, UMWA 1974 Pension Trust withdrawal and closure costs incurred to date considered probable of recovery.

The Company had regulatory assets not earning a return on investment of $2.6 billion and $2.2 billion as of December 31, 2014 and 2013, respectively.

Regulatory Liabilities

Regulatory liabilities represent income to be recognized or amounts to be returned to customers in future periods. 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	2014	2013
Cost of removal[1]	28 years	$ 2,215	$ 2,009
Asset retirement obligations	23 years	169	151
Levelized depreciation	27 years	169	144
Employee benefit plans[2]	12 years	20	74
Other	Various	259	287
Total regulatory liabilities		$ 2,832	$ 2,665
Reflected as:			
Current liabilities		$ 163	$ 167
Noncurrent liabilities		2,669	2,498
Total regulatory liabilities		$ 2,832	$ 2,665

(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.

(7) Investments and Restricted Cash and Investments

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

	2014	2013
Investments:		
BYD Company Limited common stock	$ 881	$ 1,103
Rabbi trusts	386	373
Other	126	126
Total investments	1,393	1,602
Equity method investments:		
Electric Transmission Texas, LLC	515	454
Bridger Coal Company	192	178
Agua Caliente Solar, LLC	81	41
CE Generation	—	185
Other	80	85
Total equity method investments	868	943
Restricted cash and investments:		
Quad Cities Station nuclear decommissioning trust funds	424	394
Solar Star and Topaz Projects	66	236
Other	167	126
Total restricted cash and investments	657	756
Total investments and restricted cash and investments	$ 2,918	$ 3,301
Reflected as:		
Current assets	$ 115	$ 65
Noncurrent assets	2,803	3,236
Total investments and restricted cash and investments	$ 2,918	$ 3,301

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. As of December 31, 2014 and 2013, the fair value of BHE's investment in BYD Company Limited common stock was $881 million and $1.1 billion, respectively, which resulted in a unrealized gain of $649 million and $871 million as of December 31, 2014 and 2013, 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. BHE, through a subsidiary, owns 49% of Agua Caliente Solar, LLC ("Agua Caliente"), which owns a 290-MW solar project (the "Agua Caliente Project") in Arizona. In June 2014, BHE, through a subsidiary, acquired the remaining 50% interest in CE Generation, which is engaged in the independent power business, and through its subsidiaries, owns and operates geothermal generating facilities in the Imperial Valley of California and natural gas-fueled combined cycle cogeneration facilities in New York, Texas and Arizona.

During 2013, BHE recognized an impairment charge on its equity investment in CE Generation totaling $116 million. The impairment charge is reflected in equity income (loss) on the Consolidated Statements of Operations.

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.

As of December 31, 2014 and 2013, restricted cash and investments included $22 million and $201 million, respectively, restricted for construction of the Solar Star Projects and $44 million and $35 million, respectively, restricted for construction of the Topaz Project.

(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	Home-Services	Total[(1)]
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
2013:								
Credit facilities	$ 600	$ 1,200	$ 609	$ 750	$ 248	$ —	$ 665	$ 4,072
Less:								
Short-term debt	—	—	—	—	(102)	—	(130)	(232)
Tax-exempt bond support and letters of credit	(50)	(321)	(195)	(6)	—	—	—	(572)
Net credit facilities	$ 550	$ 879	$ 414	$ 744	$ 146	$ —	$ 535	$ 3,268

(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, 2014, the Company was in compliance with the covenants of its credit facilities and letter of credit arrangements.

BHE

In June 2014, BHE entered into a $1.4 billion senior unsecured credit facility expiring in June 2017 and has 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 supports BHE's commercial paper program and provides for the issuance of letters of credit. As of December 31, 2014, the weighted average interest rate on commercial paper borrowings outstanding was 0.49%. 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.

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, 2014, the weighted average interest rate on commercial paper borrowings outstanding was 0.43%. These credit facilities require that PacifiCorp's ratio of consolidated debt, including current maturities, to total capitalization not exceed 0.65 to 1.0 as of the last day of each quarter.

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

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 August 2017. 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 and 2013, $184 million and $102 million, respectively, were outstanding under the credit facility with weighted average interest rates of 1.75% and 1.74%, respectively. 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 and 2013, Northern Powergrid has $31 million and $- million, respectively, drawn on uncommitted bank facilities totaling £42 million, with a weighted average interest rate of 2.0% as of December 31, 2014.

AltaLink

ALP has a C$925 million secured revolving credit facility expiring in December 2016, which provides support for borrowing 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 2016, 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, 2014, ALP had $104 million outstanding under these facilities at a weighted average interest rate of 1.26%.

AltaLink Investments, L.P. has a C$300 million unsecured revolving term credit facility expiring in December 2019, 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, 2014, AltaLink Investments, L.P. had $147 million outstanding under this facility at a weighted average interest rate of 1.30%.

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%. There were no borrowings outstanding under the credit facility as of December 31, 2013.

Through its subsidiaries, HomeServices maintains mortgage lines of credit totaling $478 million and $275 million as of December 31, 2014 and 2013, respectively, used for mortgage banking activities that currently expire beginning in May 2015 through December 2015. 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, 2014 and 2013, HomeServices had $270 million and $124 million, respectively, outstanding under these mortgage lines of credit at a weighted average interest rate of 2.25% and 3.15%, respectively.

HomeServices has a subsidiary that maintains a mortgage line of credit totaling $25 million and $40 million as of December 31, 2014 and 2013, respectively, used for mortgage banking activities that is due on demand with a 90-day notice from either party. The mortgage line of credit has a variable rate based on LIBOR plus a spread, with a minimum rate of 3.375%. Collateral for this credit facility is equal to the loans funded with this warehouse credit and an additional $1 million of cash on deposit. As of December 31, 2014 and 2013, HomeServices had $1 million and $6 million, respectively, outstanding under its mortgage line at a weighted average interest rate of 3.375%.

BHE Renewables Letters of Credit

In connection with its bond offering, Topaz entered into a letter of credit and reimbursement facility in an aggregate principal amount of $345 million. Letters of credit issued under the letter of credit facility 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, 2014, Topaz had $245 million of letters of credit issued under this facility.

As of December 31, 2014, BHE has a letter of credit outstanding of $43 million in support of the power purchase agreement associated with the Agua Caliente Project.

As of December 31, 2014, certain renewable projects collectively have letters of credit outstanding of $63 million 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 and consists of the following, including unamortized premiums and discounts, as of December 31 (in millions):

	Par Value	2014	2013
5.00% Senior Notes, due 2014	$ —	$ —	$ 250
1.10% Senior Notes, due 2017	400	400	400
5.75% Senior Notes, due 2018	650	649	649
2.00% Senior Notes, due 2018	350	350	350
2.40% Senior Notes, due 2020	350	350	—
3.75% Senior Notes, due 2023	500	500	500
3.50% Senior Notes, due 2025	400	400	—
8.48% Senior Notes, due 2028	475	482	483
6.125% Senior Bonds, due 2036	1,700	1,699	1,699
5.95% Senior Bonds, due 2037	550	548	548
6.50% Senior Bonds, due 2037	1,000	992	992
5.15% Senior Notes, due 2043	750	746	745
4.50% Senior Notes, due 2045	750	744	—
Total BHE Senior Debt	$ 7,875	$ 7,860	$ 6,616
Reflected as:			
Current liabilities		$ —	$ 250
Noncurrent liabilities		7,860	6,366
Total BHE Senior Debt		$ 7,860	$ 6,616

Junior Subordinated Debentures

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

	Par Value	2014	2013
Junior subordinated debentures, due 2043	$ 2,294	$ 2,294	$ 2,594
Junior subordinated debentures, due 2044	1,500	1,500	—
Total BHE junior subordinated debentures - noncurrent	$ 3,794	$ 3,794	$ 2,594

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, 2014 and 2013, the interest rate was 3.0%. Interest expense to Berkshire Hathaway for the years ended December 31, 2014, 2013 and 2012 was $78 million, $3 million and $- million, respectively.

(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, 2014, 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 and discounts, as of December 31 (in millions):

	Par Value	2014	2013
PacifiCorp	$ 7,102	$ 7,089	$ 6,933
MidAmerican Funding	4,396	4,345	3,838
NV Energy	5,093	5,138	5,296
Northern Powergrid	2,267	2,334	2,487
BHE Pipeline Group	1,367	1,366	1,448
BHE Transmission	3,735	3,756	—
BHE Renewables	2,964	2,967	2,800
Total subsidiary debt	$ 26,924	$ 26,995	$ 22,802
Reflected as:			
Current liabilities		$ 1,232	$ 938
Noncurrent liabilities		25,763	21,864
Total subsidiary debt		$ 26,995	$ 22,802

PacifiCorp

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

	Par Value	2014	2013
First mortgage bonds:			
5.50% to 8.635%, due through 2019	$ 862	$ 861	$ 1,070
2.95% to 8.53%, due 2021 to 2024	1,899	1,897	1,472
6.71% due 2026	100	100	100
5.90% to 7.70%, due 2031 to 2034	500	499	499
5.25% to 6.35%, due 2035 to 2039	2,800	2,792	2,791
4.10% due 2042	300	299	299
Variable-rate series, tax-exempt bond obligations (2014-0.02% to 0.28%; 2013-0.03% to 0.52%):			
Due 2015 to 2025(1)	223	223	325
Due 2015 to 2024(1)(2)	221	221	221
Due 2016 to 2025(2)	36	36	51
Due 2017 to 2018	91	91	—
Capital lease obligations - 8.75% to 15.678%, due through 2036	70	70	105
Total PacifiCorp	$ 7,102	$ 7,089	$ 6,933

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

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

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

MidAmerican Funding

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

	Par Value	2014	2013
MidAmerican Funding:			
6.927% Senior Bonds, due 2029	$ 325	$ 289	$ 288
MidAmerican Energy:			
Tax-exempt bond obligations -			
Variable-rate series (2014-0.07%, 2013-0.08%), due 2016-2038	195	195	195
First Mortgage Bonds:			
2.40%, due 2019	500	500	350
3.70%, due 2023	250	249	249
3.50%, due 2024	300	299	—
4.80%, due 2043	350	348	348
4.40%, due 2044	400	398	—
Notes:			
4.65% Series, due 2014	—	—	350
5.95% Series, due 2017	250	250	250
5.3% Series, due 2018	350	350	349
6.75% Series, due 2031	400	397	397
5.75% Series, due 2035	300	300	300
5.8% Series, due 2036	350	350	350
Turbine purchase obligation, 1.43% due 2015(1)	426	420	412
Total MidAmerican Energy	4,071	4,056	3,550
Total MidAmerican Funding	$ 4,396	$ 4,345	$ 3,838

(1) In conjunction with the construction of wind-powered generating facilities, MidAmerican Energy has accrued as property, plant and equipment, net amounts it is not contractually obligated to pay until the future. The amounts ultimately payable were discounted and recognized upon delivery of the equipment as long-term debt. The discount is being amortized as interest expense over the period until payment is 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, 2014, MidAmerican Energy's eligible property subject to the lien of the mortgage totaled approximately $12 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 and discounts, as of December 31 (dollars in millions):

	Par Value	2014	2013
NV Energy:			
Variable-rate Term Loan, due 2014[(1)]	$ —	$ —	$ 195
6.250% Senior Notes, due 2020	315	362	369
Total NV Energy	315	362	564
Nevada Power:			
General and Refunding Mortgage Securities:			
5.875% Series L, due 2015	250	250	250
5.950% Series M, due 2016	210	210	210
6.500% Series O, due 2018	325	323	324
6.500% Series S, due 2018	499	498	499
7.125% Series V, due 2019	500	501	501
6.650% Series N, due 2036	367	361	363
6.750% Series R, due 2037	349	348	349
5.375% Series X, due 2040	250	249	249
5.450% Series Y, due 2041	250	250	250
Variable-rate series (2014-0.455% to 0.464%, 2013 0.454% to 0.459%):			
Pollution Control Revenue Bonds Series 2006A, due 2032	38	38	38
Pollution Control Revenue Bonds Series 2006, due 2036	38	38	38
Capital lease obligations - 2.75% to 11.6%, due through 2054	510	510	461
Total Nevada Power	3,586	3,576	3,532
Sierra Pacific:			
General and Refunding Mortgage Securities:			
6.000% Series M, due 2016	450	452	453
3.375% Series T, due 2023	250	250	250
6.750% Series P, due 2037	252	258	259
Variable-rate series (2014-0.464% to 0.466%, 2013-0.459% to 0.463%):			
Pollution Control Revenue Bonds Series 2006A, due 2031	58	58	58
Pollution Control Revenue Bonds Series 2006B, due 2036	75	75	75
Pollution Control Revenue Bonds Series 2006C, due 2036	81	81	81
Capital lease obligations - 2.7% to 8.814%, due through 2054	26	26	24
Total Sierra Pacific	1,192	1,200	1,200
Total NV Energy	$ 5,093	$ 5,138	$ 5,296

(1) The term loan had a variable interest rate based on LIBOR plus a spread that varied during the term of the agreement. The variable interest rate as of December 31, 2013 was 1.92%. The Company had an interest rate swap that fixed the interest rate at 2.56% as of December 31, 2013.

Utility plant of $3.5 billion and $1.5 billion is subject to the liens of the Nevada Power's and Sierra Pacific's, respectively, indentures under which its respective General and Refunding Mortgage Securities are issued.

Northern Powergrid

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

	Par Value[1]	2014	2013
8.875% Bonds, due 2020	$ 156	$ 174	$ 189
9.25% Bonds, due 2020	311	339	366
3.901% to 4.586% European Investment Bank loans, due 2018 to 2022	420	420	444
7.25% Bonds, due 2022	311	328	349
7.25% Bonds, due 2028	290	299	319
4.375% Bonds, due 2032	234	231	245
5.125% Bonds, due 2035	311	310	328
5.125% Bonds, due 2035	234	233	247
Total Northern Powergrid	$ 2,267	$ 2,334	$ 2,487

(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 and discounts, as of December 31 (dollars in millions):

	Par Value	2014	2013
Northern Natural Gas:			
5.125% Senior Notes, due 2015	$ 100	$ 100	$ 100
5.75% Senior Notes, due 2018	200	200	200
4.25% Senior Notes, due 2021	200	200	200
5.8% Senior Bonds, due 2037	150	150	150
4.1% Senior Bonds, due 2042	250	249	250
Total Northern Natural Gas	900	899	900
Kern River:			
6.676% Senior Notes, due 2016	167	167	197
4.893% Senior Notes, due 2018	300	300	351
Total Kern River	467	467	548
Total BHE Pipeline Group	$ 1,367	$ 1,366	$ 1,448

Kern River's long-term debt amortizes monthly. Kern River provides a debt service reserve letter of credit in amounts that approximate the next six months of principal and interest payments due on the loans, which were equal to $56 million as of December 31, 2014 and 2013.

BHE Transmission

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

	Par Value[1]	2014	2013
AltaLink Investments, L.P.:			
Series 09-1 Senior Bonds, 5.207%, due 2016	$ 128	$ 136	$ —
Series 12-1 Senior Bonds, 3.674%, due 2019	172	181	—
Series 13-1 Senior Bonds, 3.265%, due 2020	172	177	—
Total AltaLink Investments, L.P.	472	494	—
AltaLink Holdings, L.P. Senior debentures, 10.5%, due 2015	78	78	—
ALP:			
Series 2008-1 Notes, 5.243%, due 2018	172	171	—
Series 2013-2 Notes, 3.621%, due 2020	108	108	—
Series 2012-2 Notes, 2.978%, due 2022	237	237	—
Series 2013-4 Notes, 3.668%, due 2023	430	430	—
Series 2014-1 Notes, 3.399%, due 2024	301	301	—
Series 2006-1 Notes, 5.249%, due 2036	129	129	—
Series 2010-1 Notes, 5.381%, due 2040	108	108	—
Series 2010-2 Notes, 4.872%, due 2040	129	129	—
Series 2011-1 Notes, 4.462%, due 2041	237	237	—
Series 2012-1 Notes, 3.99%, due 2042	452	452	—
Series 2013-3 Notes, 4.922%, due 2043	301	301	—
Series 2014-3 Notes, 4.054%, due 2044	254	254	—
Series 2013-1 Notes, 4.446%, due 2053	215	215	—
Series 2014-2 Notes, 4.274%, due 2064	112	112	—
Total AltaLink, L.P.	3,185	3,184	—
Total BHE Transmission	$ 3,735	$ 3,756	$ —

(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, as of December 31 (dollars in millions):

	Par Value	2014	2013
Fixed-rate[1]:			
CE Generation Bonds, 7.416%, due 2018	$ 123	$ 125	$ —
Salton Sea Funding Corporation Bonds, 7.475%, due 2018	69	71	—
Cordova Funding Corporation Bonds, 8.48% to 9.07%, due 2019	126	125	139
Bishop Hill Holdings Senior Notes, 5.125%, due 2032	109	109	114
Solar Star Funding Senior Notes, 5.375%, due 2035	1,000	1,000	1,000
Topaz Solar Farms Senior Notes, 5.750%, due 2039	850	850	850
Topaz Solar Farms Senior Notes, 4.875%, due 2039	250	250	250
Other	27	27	30
Variable-rate[1]:			
Pinyon Pines I and II Term Loans, due 2019[2]	401	401	417
Wailuku Special Purpose Revenue Bonds, 0.09%, due 2021	9	9	—
Total BHE Renewables	$ 2,964	$ 2,967	$ 2,800

(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, 2014 and 2013 was 1.88% and 2.87%, 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% and 4.53% as of December 31, 2014 and 2013, respectively.

Annual Repayments of Long-Term Debt

The annual repayments of BHE and subsidiary debt for the years beginning January 1, 2015 and thereafter, excluding fair value adjustments and unamortized premiums and discounts, are as follows (in millions):

	2015	2016	2017	2018	2019	2020 and Thereafter	Total
BHE senior notes	$ —	$ —	$ 400	$ 1,000	$ —	$ 6,475	$ 7,875
BHE junior subordinated debentures	—	—	—	—	—	3,794	3,794
PacifiCorp	157	71	58	589	353	5,874	7,102
MidAmerican Funding	426	34	254	350	500	2,832	4,396
NV Energy	265	673	16	840	519	2,780	5,093
Northern Powergrid	—	—	—	62	62	2,143	2,267
BHE Pipeline Group	185	191	62	329	—	600	1,367
BHE Transmission	78	129	—	172	172	3,184	3,735
BHE Renewables	121	168	172	179	463	1,861	2,964
Totals	$ 1,232	$ 1,266	$ 962	$ 3,521	$ 2,069	$ 29,543	$ 38,593

(11) Income Taxes

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

	2014	2013	2012
Current:			
Federal	$ (1,872)	$ (985)	$ (1,314)
State	(3)	(2)	(67)
Foreign	129	121	121
	(1,746)	(866)	(1,260)
Deferred:			
Federal	2,296	1,306	1,475
State	37	(247)	(11)
Foreign	11	(59)	(51)
	2,344	1,000	1,413
Investment tax credits - the Utilities	(9)	(4)	(5)
Total	$ 589	$ 130	$ 148

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

	2014	2013	2012
Federal statutory income tax rate	35%	35%	35%
Income tax credits	(10)	(14)	(14)
State income tax, net of federal income tax benefit	1	(9)	(3)
Income tax effect of foreign income	(3)	(6)	(7)
Equity income (loss)	2	(1)	2
Other, net	(2)	2	(4)
Effective income tax rate	23%	7%	9%

Income tax credits relate primarily to production tax credits earned by wind-powered generating facilities owned by MidAmerican Energy, PacifiCorp, and Bishop Hill Energy II LLC. 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 increased for 2013 compared to 2012 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 $54 million in 2013 and $38 million in 2012 related to the enactment of reductions in the United Kingdom corporate income tax rate. 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. In July 2012, the corporate income tax rate was reduced from 25% to 24% effective April 1, 2012, with a further reduction to 23% effective April 1, 2013.

Berkshire Hathaway includes the Company in its United States federal income tax return. As of December 31, 2014 and 2013, the Company had current income taxes receivable from Berkshire Hathaway of $1.1 billion and $25 million, respectively.

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

	2014	2013
Deferred income tax assets:		
Federal and state carryforwards	$ 781	$ 1,001
Regulatory liabilities	812	825
AROs	249	234
Employee benefits	187	75
Derivative contracts	62	28
Other	781	740
Total deferred income tax assets	2,872	2,903
Valuation allowances	(23)	(29)
Total deferred income tax assets, net	2,849	2,874
Deferred income tax liabilities:		
Property-related items	(11,989)	(10,727)
Regulatory assets	(1,374)	(1,047)
Investments	(699)	(767)
Other	(301)	(287)
Total deferred income tax liabilities	(14,363)	(12,828)
Net deferred income tax liability	$ (11,514)	$ (9,954)
Reflected as:		
Current assets - other	$ 291	$ 211
Current liabilities - other	(3)	(7)
Deferred income taxes	(11,802)	(10,158)
	$ (11,514)	$ (9,954)

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

	Federal	State
Net operating loss carryforwards(1)	$ 409	$ 8,629
Deferred income taxes on net operating loss carryforwards	$ 155	$ 474
Expiration dates	2023-2034	2015-2034
Foreign and other tax credits(2)	$ 122	$ 30
Expiration dates	2023- indefinite	2016- indefinite

(1) The federal net operating loss carry forwards relate principally to net operating loss carryforwards of NV Energy generated prior to BHE's ownership.

(2) Includes $74 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, 2014 the statute of limitation had not begun on the foreign tax credit carryforwards.

The United States Internal Revenue Service has effectively settled 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 and the March 2004, 2005 and 2006 tax years in Colorado and Utah). Examinations have been closed in the United Kingdom through at least 2010 and in the Philippines through at least 2010.

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):

	2014	2013
Beginning balance	$ 211	$ 223
Additions based on tax positions related to the current year	11	18
Additions for tax positions of prior years	48	80
Reductions for tax positions of prior years	(50)	(106)
Statute of limitations	(1)	4
Settlements	—	(10)
Interest and penalties	1	2
Ending balance	$ 220	$ 211

As of December 31, 2014 and 2013, the Company had unrecognized tax benefits totaling $188 million and $179 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		
	2014	2013	2012	2014	2013	2012
Service cost	$ 36	$ 24	$ 25	$ 14	$ 14	$ 11
Interest cost	131	87	98	46	33	36
Expected return on plan assets	(164)	(119)	(119)	(53)	(44)	(43)
Net amortization	44	58	37	(3)	6	1
Net periodic benefit cost	$ 47	$ 50	$ 41	$ 4	$ 9	$ 5

Funded Status

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

	Pension		Other Postretirement	
	2014	2013	2014	2013
Plan assets at fair value, beginning of year	$ 2,711	$ 1,655	$ 852	$ 650
NV Energy Transaction	—	818	—	110
Employer contributions	37	71	2	8
Participant contributions	—	—	11	8
Actual return on plan assets	188	359	54	127
Benefits paid	(218)	(192)	(61)	(51)
Plan assets at fair value, end of year	$ 2,718	$ 2,711	$ 858	$ 852

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

	Pension		Other Postretirement	
	2014	2013	2014	2013
Benefit obligation, beginning of year	$ 2,821	$ 2,237	$ 987	$ 845
NV Energy Transaction	—	823	—	154
Service cost	36	24	14	14
Interest cost	131	87	46	33
Participant contributions	—	—	11	8
Actuarial loss (gain)	349	(158)	(61)	(16)
Benefits paid	(218)	(192)	(61)	(51)
Benefit obligation, end of year	$ 3,119	$ 2,821	$ 936	$ 987
Accumulated benefit obligation, end of year	$ 3,086	$ 2,747		

In conjunction with the Utah Mine Disposition described in Note 6, in December 2014, Energy West Mining Company reached a labor settlement with the UMWA covering union employees at PacifiCorp's Deer Creek mining operations. As a result of the labor settlement, the UMWA agreed to assume PacifiCorp's other postretirement benefit obligation associated with UMWA plan participants in exchange for PacifiCorp transferring $150 million to the UMWA. Transfer of the assets to the UMWA and settlement of this obligation is expected to occur in June 2015, which will result in a remeasurement of the other postretirement plan assets and benefit obligation. No curtailment accounting will be triggered as a result of the settlement due to an insignificant impact to the average remaining service lives in the plan. The actuarial gain associated with the other postretirement benefit obligation during the year ended December 31, 2014 includes a gain that reduced the benefit obligation resulting from the $150 million to be transferred to the UMWA in June 2015 as a result of the contractually binding labor settlement.

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

	Pension		Other Postretirement	
	2014	2013	2014	2013
Plan assets at fair value, end of year	$ 2,718	$ 2,711	$ 858	$ 852
Benefit obligation, end of year	3,119	2,821	936	987
Funded status	$ (401)	$ (110)	$ (78)	$ (135)
Amounts recognized on the Consolidated Balance Sheets:				
Other assets	$ 12	$ 98	$ 10	$ 21
Other current liabilities	(14)	(19)	—	—
Other long-term liabilities	(399)	(189)	(88)	(156)
Amounts recognized	$ (401)	$ (110)	$ (78)	$ (135)

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 $247 million and $235 million as of December 31, 2014 and 2013, respectively. These assets are not included in the plan assets in the above table, but are reflected in noncurrent 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	
	2014	2013	2014	2013
Fair value of plan assets	$ 1,987	$ 1,171	$ 598	$ 596
Projected benefit obligation	$ 2,401	$ 1,379	$ 686	$ 751
Accumulated benefit obligation	$ 2,380	$ 1,374		

Unrecognized Amounts

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

	Pension		Other Postretirement	
	2014	2013	2014	2013
Net loss	$ 757	$ 487	$ 108	$ 183
Prior service credit	(31)	(42)	(87)	(102)
Regulatory deferrals	(3)	(4)	2	2
Total	$ 723	$ 441	$ 23	$ 83

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

	Regulatory Asset	Regulatory Liability	Accumulated Other Comprehensive Loss	Total
Pension				
Balance, December 31, 2012	$ 712	$ —	$ 25	$ 737
NV Energy acquisition	161	—	—	161
Net gain arising during the year	(334)	(51)	(14)	(399)
Net amortization	(49)	(7)	(2)	(58)
Total	(222)	(58)	(16)	(296)
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

	Regulatory Asset	Regulatory Liability	Total
Other Postretirement			
Balance, December 31, 2012	$ 188	$ (13)	$ 175
NV Energy Acquisition	12	—	12
Net gain arising during the year	(94)	(4)	(98)
Net amortization	(7)	1	(6)
Total	(89)	(3)	(92)
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

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

	Net Loss	Prior Service Credit	Regulatory Deferrals	Total
Pension	$ 65	$ (10)	$ (1)	$ 54
Other postretirement	4	(16)	1	(11)
Total	$ 69	$ (26)	$ —	$ 43

Plan Assumptions

Weighted-average assumptions used to determine benefit obligations and net periodic benefit cost were as follows:

	Pension			Other Postretirement		
	2014	2013	2012	2014	2013	2012
Benefit obligations as of December 31:						
Discount rate	4.00%	4.81%	4.03%	3.88%	4.82%	4.01%
Rate of compensation increase	2.75%	3.00%	3.00%	N/A	N/A	N/A
Net periodic benefit cost for the years ended December 31:						
Discount rate	4.81%	4.03%	4.84%	4.82%	4.01%	4.90%
Expected return on plan assets	6.86%	7.50%	7.50%	7.34%	7.44%	7.50%
Rate of compensation increase	3.00%	3.00%	3.50%	N/A	N/A	N/A

In establishing its assumption as to the expected return on plan assets, 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.

	2014	2013
Assumed healthcare cost trend rates as of December 31:		
Healthcare cost trend rate assumed for next year	8.00%	7.88%
Rate that the cost trend rate gradually declines to	5.00%	4.96%
Year that the rate reaches the rate it is assumed to remain at	2025	2019, 2029

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, 2014	$ 4	$ (3)
Other postretirement benefit obligation as of December 31, 2014	7	(6)

Contributions and Benefit Payments

Employer contributions to the pension and other postretirement benefit plans are expected to be $34 million and $- million, respectively, during 2015. 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 2015 through 2019 and for the five years thereafter are summarized below (in millions):

	Projected Benefit Payments	
	Pension	Other Postretirement
2015	$ 216	$ 210
2016	225	56
2017	223	56
2018	225	58
2019	225	58
2020-2024	1,073	283

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

Plan Assets

Investment Policy and Asset Allocations

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 return on assets assumption for each plan is based on a weighted-average of the expected historical performance for the types of assets in which the plans invest.

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, 2014:

	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, 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
As of December 31, 2013				
Cash equivalents	$ 2	$ 78	$ —	$ 80
Debt securities:				
United States government obligations	129	—	—	129
International government obligations	—	4	—	4
Corporate obligations	—	242	—	242
Municipal obligations	—	28	—	28
Agency, asset and mortgage-backed obligations	—	132	—	132
Equity securities:				
United States companies	709	—	—	709
International companies	133	—	—	133
Investment funds[2]	320	817	—	1,137
Limited partnership interests[3]	—	—	86	86
Real estate funds	—	—	31	31
Total	$ 1,293	$ 1,301	$ 117	$ 2,711

(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 61% and 39%, respectively, for 2014 and 60% and 40%, respectively, for 2013. Additionally, these funds are invested in United States and international securities of approximately 64% and 36%, respectively, for 2014 and 65% and 35%, respectively, for 2013.

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

The following table presents the fair value of plan assets, by major category, for 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, 2014				
Cash equivalents[(2)]	$ 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
As of December 31, 2013				
Cash equivalents	$ 5	$ 4	$ —	$ 9
Debt securities:				
United States government obligations	11	—	—	11
Corporate obligations	—	18	—	18
Municipal obligations	—	38	—	38
Agency, asset and mortgage-backed obligations	—	19	—	19
Equity securities:				
United States companies	294	—	—	294
International companies	8	—	—	8
Investment funds[(3)]	296	153	—	449
Limited partnership interests[(4)]	—	—	6	6
Total	$ 614	$ 232	$ 6	$ 852

(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 the UMWA in June 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 2014 and 57% and 43%, respectively, for 2013. Additionally, these funds are invested in United States and international securities of approximately 69% and 31%, respectively, for 2014 and 72% and 28%, respectively, for 2013.

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

When available, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value. In the absence of a quoted market price or net asset value of an identical security, the fair value is determined using pricing models or net asset values based on observable market inputs and quoted market prices of securities with similar characteristics. When observable market data is not available, the fair value is determined using unobservable inputs, such as estimated future cash flows, purchase multiples paid in other comparable third-party transactions or other information. Investments in limited 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, 2011	$ 71	$ 24	$ 6
Actual return on plan assets still held at period end	7	2	1
Purchases, sales, distributions and settlements	18	—	—
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

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):

	2014	2013	2012
Service cost	$ 24	$ 22	$ 19
Interest cost	95	85	85
Expected return on plan assets	(124)	(101)	(104)
Net amortization	51	53	43
Net periodic benefit cost	$ 46	$ 59	$ 43

Funded Status

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

	2014	2013
Plan assets at fair value, beginning of year	$ 2,177	$ 1,996
Employer contributions	89	79
Participant contributions	2	3
Actual return on plan assets	337	138
Benefits paid	(92)	(83)
Foreign currency exchange rate changes	(145)	44
Plan assets at fair value, end of year	$ 2,368	$ 2,177

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

	2014	2013
Benefit obligation, beginning of year	$ 2,185	$ 2,047
Service cost	24	22
Interest cost	95	85
Participant contributions	2	3
Actuarial loss	205	70
Benefits paid	(92)	(83)
Foreign currency exchange rate changes	(140)	41
Benefit obligation, end of year	$ 2,279	$ 2,185
Accumulated benefit obligation, end of year	$ 2,019	$ 1,917

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):

	2014	2013
Plan assets at fair value, end of year	$ 2,368	$ 2,177
Benefit obligation, end of year	2,279	2,185
Funded status	$ 89	$ (8)
Amounts recognized on the Consolidated Balance Sheets:		
Other assets	$ 89	$ —
Other long-term liabilities	—	(8)
Amounts recognized	$ 89	$ (8)

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):

	2014	2013
Net loss	$ 655	$ 750
Prior service cost	—	1
Total	$ 655	$ 751

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):

	2014	2013
Balance, beginning of year	$ 751	$ 759
Net (gain) loss arising during the year	(8)	32
Net amortization	(51)	(53)
Foreign currency exchange rate changes	(37)	13
Total	(96)	(8)
Balance, end of year	$ 655	$ 751

The net loss that will be amortized from accumulated other comprehensive loss in 2015 into net periodic benefit cost is estimated to be $63 million.

Plan Assumptions

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

	2014	2013	2012
Benefit obligations as of December 31:			
Discount rate	3.60%	4.40%	4.40%
Rate of compensation increase	2.80%	3.15%	2.80%
Rate of future price inflation	2.80%	3.15%	2.80%
Net periodic benefit cost for the years ended December 31:			
Discount rate	4.40%	4.40%	4.80%
Expected return on plan assets	6.10%	5.70%	6.10%
Rate of compensation increase	3.15%	2.80%	2.80%
Rate of future price inflation	3.15%	2.80%	2.80%

Contributions and Benefit Payments

Employer contributions to the UK Plan are expected to be £50 million during 2015. The expected benefit payments to participants in the UK Plan for 2015 through 2019 and for the five years thereafter, using the foreign currency exchange rate as of December 31, 2014, are summarized below (in millions):

2015	$ 89
2016	91
2017	93
2018	95
2019	97
2020-2024	553

Plan Assets

<u>Investment Policy and Asset Allocations</u>

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, 2014:

	%
Debt securities[(1)]	50-55
Equity securities[(1)]	35-40
Real estate funds	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, 2014				
Cash equivalents	$ 43	$ —	$ —	$ 43
Debt securities:				
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
As of December 31, 2013				
Cash equivalents	$ 23	$ —	$ —	$ 23
Debt securities:				
United States government obligations	5	—	—	5
United Kingdom government obligations	375	—	—	375
Other international government obligations	—	2	—	2
Corporate obligations	—	206	—	206
Investment funds[(2)]	122	1,265	—	1,387
Real estate funds	—	—	179	179
Total	$ 525	$ 1,473	$ 179	$ 2,177

(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%, respectively, for 2014 and 45% and 55%, respectively, for 2013.

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		
	2014	2013	2012
Beginning balance	$ 179	$ 163	$ 158
Actual return on plan assets still held at period end	33	12	(3)
Foreign currency exchange rate changes	(13)	4	8
Ending balance	$ 199	$ 179	$ 163

Defined Contribution Plans

The Company sponsors various defined contribution plans covering substantially all employees. The Company's contributions vary depending on the plan, but are based primarily on each participant's level of contribution and cannot exceed the maximum allowable for tax purposes. Certain employees now receive enhanced benefits in these plans and no longer accrue benefits in the noncontributory defined benefit pension plans. The Company's contributions to these plans were $83 million, $63 million and $62 million for the years ended December 31, 2014, 2013 and 2012, 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 and $2.0 billion as of December 31, 2014 and 2013, respectively.

The following table presents the Company's ARO liabilities by asset type as of December 31 (in millions):

	2014	2013
Fossil fuel facilities	$ 334	$ 315
Quad Cities Station	265	254
Wind generating facilities	75	59
Offshore pipeline facilities	31	35
Solar generating facilities	9	5
Other	39	28
Total asset retirement obligations	$ 753	$ 696
Quad Cities Station nuclear decommissioning trust funds	$ 424	$ 394

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

	2014	2013
Beginning balance	$ 696	$ 490
Acquisitions	12	80
Change in estimated costs	3	88
Additions	15	18
Retirements	(8)	(6)
Accretion	35	26
Ending balance	$ 753	$ 696
Reflected as:		
Other current liabilities	$ 66	$ 18
Other long-term liabilities	687	678
Total ARO liability	$ 753	$ 696

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.

The 2013 change in estimated costs is primarily due to an increase of $98 million in ARO liabilities as a result of changes in the amount and timing of cash flow for ash pond closures at some of MidAmerican Energy's thermal generating facilities.

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.

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

(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. MidAmerican Energy 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, 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, 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, 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 (payable) receivable	—	—	56	19	75
Total derivatives - net basis	$ 41	$ 67	$ (97)	$ (133)	$ (122)
As of December 31, 2013					
Not designated as hedging contracts:					
Commodity assets[1]	$ 16	$ 62	$ 18	$ 2	$ 98
Commodity liabilities[1]	(2)	(1)	(78)	(145)	(226)
Interest rate assets	3	5	—	—	8
Interest rate liabilities	—	—	(1)	—	(1)
Total	17	66	(61)	(143)	(121)
Designated as hedging contracts:					
Commodity assets	1	—	1	—	2
Commodity liabilities	(1)	—	(5)	(8)	(14)
Interest rate assets	—	6	—	—	6
Interest rate liabilities	—	—	(6)	—	(6)
Total	—	6	(10)	(8)	(12)
Total derivatives	17	72	(71)	(151)	(133)
Cash collateral receivable	(2)	—	1	13	12
Total derivatives - net basis	$ 15	$ 72	$ (70)	$ (138)	$ (121)

(1) The Company's commodity derivatives not designated as hedging contracts are generally included in regulated rates, and as of December 31, 2014 and 2013, a net regulatory asset of $223 million and $182 million, respectively, was recorded related to the net derivative liability of $156 million and $128 million, respectively.

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		
	2014	2013	2012
Beginning balance	$ 182	$ 235	$ 400
NV Energy Transaction	—	47	—
Changes in fair value recognized in net regulatory assets	96	29	69
Net (losses) gains reclassified to operating revenue	(32)	8	63
Net losses reclassified to cost of sales	(23)	(137)	(297)
Ending balance	$ 223	$ 182	$ 235

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. 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		
	2014	2013	2012
Beginning balance	$ 12	$ 32	$ 46
Changes in fair value recognized in OCI	(6)	(9)	20
Net gains reclassified to operating revenue	—	—	4
Net gains (losses) reclassified to cost of sales	26	(11)	(38)
Ending balance	$ 32	$ 12	$ 32

Certain derivative contracts, principally interest rate locks, 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. 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, 2014, 2013 and 2012, hedge ineffectiveness was insignificant. As of December 31, 2014, the Company had cash flow hedges with expiration dates extending through December 2019 and $22 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	2014	2013
Electricity purchases (sales)	Megawatt hours	6	(5)
Natural gas purchases	Decatherms	308	322
Fuel purchases	Gallons	2	9
Interest rate swaps	US$	443	650
Mortgage sale commitments, net	US$	(264)	(121)

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. 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 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, 2014, 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 $243 million and $176 million as of December 31, 2014 and 2013, respectively, for which the Company had posted collateral of $28 million and $12 million, respectively, in the form of cash deposits. If all credit-risk-related contingent features for derivative contracts in liability positions had been triggered as of December 31, 2014 and 2013, the Company would have been required to post $182 million and $147 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, 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)
As of December 31, 2013					
Assets:					
Commodity derivatives	$ 3	$ 28	$ 69	$ (27)	$ 73
Interest rate derivatives	—	14	—	—	14
Mortgage loans held for sale	—	130	—	—	130
Money market mutual funds[2]	809	—	—	—	809
Debt securities:					
United States government obligations	134	—	—	—	134
International government obligations	—	1	—	—	1
Corporate obligations	—	38	—	—	38
Municipal obligations	—	2	—	—	2
Agency, asset and mortgage-backed obligations	—	2	—	—	2
Auction rate securities	—	—	44	—	44
Equity securities:					
United States companies	214	—	—	—	214
International companies	1,107	—	—	—	1,107
Investment funds	114	—	—	—	114
	$ 2,381	$ 215	$ 113	$ (27)	$ 2,682
Liabilities:					
Commodity derivatives	$ (1)	$ (230)	$ (9)	$ 39	$ (201)
Interest rate derivatives	—	(7)	—	—	$ (7)
	$ (1)	$ (237)	$ (9)	$ 39	$ (208)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $75 million and $12 million as of December 31, 2014 and 2013, respectively.

(2) Amounts are included in cash and cash equivalents; other current assets; and 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			Auction Rate Securities		
	2014	2013	2012	2014	2013	2012
Beginning balance	$ 60	$ 32	$ 23	$ 44	$ 41	$ 35
Changes included in earnings	19	34	10	—	—	—
Changes in fair value recognized in OCI	—	(2)	—	1	3	7
Changes in fair value recognized in net regulatory assets	5	1	(2)	—	—	—
Purchases	1	4	27	—	—	—
Sales	—	—	—	—	—	(1)
Settlements	1	(9)	(26)	—	—	—
Transfers from Level 2	(35)	—	—	—	—	—
Ending balance	$ 51	$ 60	$ 32	$ 45	$ 44	$ 41

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):

	2014		2013	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 38,649	$ 43,863	$ 32,012	$ 34,881

(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. In May 2012, the Plaintiff filed a motion seeking exemplary damages. Under the Utah Uniform Trade Secrets law, the judge may award exemplary damages in an additional amount not to exceed twice the original award. The Plaintiff also filed a motion to seek recovery of attorneys' fees in an amount equal to 40% of all amounts ultimately awarded in the case. In October 2012, PacifiCorp filed post-trial motions for a judgment notwithstanding the verdict and a new trial. As a result of a hearing in December 2012, the trial judge denied PacifiCorp's post-trial motions with the exception of reducing the aggregate amount of damages to $113 million. In January 2013, the Plaintiff filed a motion for prejudgment interest. An initial judgment was entered in April 2013 in which the trial judge denied the Plaintiff's motions for exemplary damages and prejudgment interest and ruled that PacifiCorp must pay the Plaintiff's attorneys' fees based on applying a reasonable rate to hours worked. In May 2013, a final judgment was entered against PacifiCorp in the amount of $115 million, which includes the $113 million of aggregate damages previously awarded and amounts awarded for the Plaintiff's attorneys' fees. The final judgment also ordered that postjudgment interest accrue beginning as of the date of the April 2013 initial judgment. In May 2013, PacifiCorp posted a surety bond issued by a subsidiary of Berkshire Hathaway to secure its estimated obligation. PacifiCorp strongly disagrees with the jury's verdict and is vigorously pursuing all appellate measures. Both PacifiCorp and the Plaintiff filed appeals with the Utah Supreme Court. Briefing before the Utah Supreme Court is complete and oral arguments will most likely be held in 2015. As of December 31, 2014, PacifiCorp had accrued $119 million for the final judgment and postjudgment interest, and believes the likelihood of any additional material loss is remote; however, any additional awards against PacifiCorp could also have a material effect on the consolidated financial results. Any payment of damages will be at the end of the appeals process, which could take as long as several years.

Commitments

The Company has the following firm commitments that are not reflected on the Consolidated Balance Sheet. Minimum payments as of December 31, 2014 are as follows (in millions):

	2015	2016	2017	2018	2019	2020 and Thereafter	Total
Contract type:							
Fuel, capacity and transmission contract commitments	$ 2,327	$ 1,765	$ 1,553	$ 1,216	$ 1,140	$ 8,777	$ 16,778
Construction commitments	1,280	117	18	8	3	9	1,435
Operating leases and easements	143	120	102	84	67	861	1,377
Maintenance, service and other contracts	187	160	161	153	161	966	1,788
	$ 3,937	$ 2,162	$ 1,834	$ 1,461	$ 1,371	$ 10,613	$ 21,378

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.

In 2012, MidAmerican Energy signed new long-term rail transportation contracts with BNSF Railway Company ("BNSF"), an affiliate company, and Union Pacific Railroad Company ("UP") for the transportation of coal to all of the MidAmerican Energy-operated coal-fueled generating facilities. These contracts replaced a long-term contract with UP that expired December 31, 2012. For the years ended December 31, 2014 and 2013, $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:

- The Topaz Project, which is a 550-MW solar project in California, and the Solar Star Projects, which are a combined 579-MW solar project in California, are in construction. BHE has committed to separately provide Topaz Solar Farms LLC and Solar Star Funding, LLC and its subsidiaries with equity to fund the costs of the projects in an amount up to $2.44 billion for the Topaz Project and $2.75 billion for the Solar Star Projects, less, among other things, the gross proceeds of long-term debt issuances, project revenue prior to completion and the total equity contributions made by BHE or its subsidiaries. As of December 31, 2014, the remaining equity commitment for the Topaz Project is $142 million and for the Solar Star Projects is $802 million. If BHE does not maintain a minimum credit rating from two of the following three ratings agencies of at least BBB- from Standard & Poor's Ratings Services or Fitch Ratings or Baa3 from Moody's Investors Service, BHE's obligations under the equity commitment agreements would be supported by cash collateral or a letter of credit issued by a financial institution that meets certain minimum criteria specified in the financing documents. Upon reaching project construction completion and other requirements under each of the project documents, BHE will have no further obligation to make any equity contributions and any unused equity contribution obligations will be canceled under each project's respective equity commitment agreement.
- PacifiCorp's costs associated with investments in emissions control equipment and certain transmission and distribution projects.
- MidAmerican Energy's costs consist primarily of contracts for the construction of wind-powered generating facilities in 2015 and the construction in 2015 through 2017 of four Multi-Value Projects approved by the Midcontinent Independent System Operator, Inc. for high voltage transmission lines in Iowa and Illinois.

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 $146 million for 2014, $118 million for 2013 and $112 million for 2012.

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 commence no earlier than 2020.

Under the KHSA, PacifiCorp and its customers are protected from uncapped dam removal costs and liabilities. For dam removal to occur, federal legislation consistent with the KHSA must be enacted to provide, among other things, protection for PacifiCorp from all liabilities associated with dam removal activities. If Congress does not enact legislation, then PacifiCorp will resume relicensing with the FERC. In May 2014, a bill was introduced in the United States Senate that, if passed by both houses of Congress, would enact the KHSA and companion agreements that seek to resolve other water-related conflicts and restore habitat in the Klamath basin. A hearing on the bill before a Senate Energy and Natural Resources subcommittee was held in June 2014, and the bill was voted out of committee and referred to the full Senate for consideration in November 2014. However, the bill was not passed by Congress prior to the end of the 2014 session. In January 2015, the bill was re-introduced into Congress.

In addition, the KHSA limits PacifiCorp's contribution to dam removal costs to no more than $200 million, of which up to $184 million would be collected from PacifiCorp's Oregon customers with the remainder to be collected from PacifiCorp's California customers. Additional funding of up to $250 million for dam removal costs is to be provided by the State of California. California voters approved a water bond measure in November 2014 from which the State of California's contribution towards dam removal costs will be drawn. If dam removal costs exceed the combined funding that will be available from PacifiCorp's Oregon and California customers and the State of California, sufficient funds would need to be provided by an entity other than PacifiCorp in order for the KHSA and dam removal to proceed.

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

As of December 31, 2014, PacifiCorp's assets included $92 million of costs associated with the Klamath hydroelectric system's mainstem dams and the associated relicensing and settlement costs, which are being depreciated and amortized in accordance with state regulatory approvals through either December 31, 2019 or December 31, 2022.

Hydroelectric Commitments

Certain of PacifiCorp's hydroelectric licenses contain requirements for PacifiCorp to make certain capital and operating expenditures related to its hydroelectric facilities. PacifiCorp estimates it is obligated to make capital expenditures of approximately $203 million over the next 10 years related to these licenses.

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 $11.8 billion as of December 31, 2014.

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 $17.4 billion as of December 31, 2014.

(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, 2011	$ (491)	$ (307)	$ 142	$ 15	$ (641)
Other comprehensive (loss) income	(84)	135	119	8	178
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)

Reclassifications from AOCI to net income for the years ended December 31, 2014, 2013 and 2012 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, 2014 and 2013, which are comprised of the following:

The total outstanding preferred stock of PacifiCorp, which does not have mandatory redemption requirements, is $2 million as of December 31, 2014 and 2013 and accrues annual dividends of 6.0% and 7.0%. 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.

In April 2013, MidAmerican Energy redeemed and canceled all of the outstanding shares of each series of its preferred securities at the stated redemption prices, which in aggregate totaled $28 million including dividends.

The total outstanding 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, was $56 million as of December 31, 2014 and 2013.

(20) Other, Net

Other, net, as shown on the Consolidated Statements of Operations, for the years ending December 31 consists of the following (in millions):

	2014	2013	2012
Interest and dividend income	$ 38	$ 15	$ 12
Corporate-owned life insurance income	19	34	21
Other, net	23	17	23
Total other, net	$ 80	$ 66	$ 56

(21) 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):

	2014	2013	2012
Supplemental disclosure of cash flow information:			
Interest paid, net of amounts capitalized	$ 1,585	$ 1,073	$ 1,046
Income taxes received, net[1]	$ 635	$ 1,105	$ 1,341
Supplemental disclosure of non-cash investing and financing transactions:			
Accruals related to property, plant and equipment additions	$ 1,143	$ 661	$ 606
Deferred payments on equipment purchased for wind-powered generation at MidAmerican Energy[2]	$ —	$ —	$ 406

(1) Includes $764 million, $1.2 billion and $1.5 billion of income taxes received from Berkshire Hathaway in 2014, 2013 and 2012, respectively.

(2) In conjunction with the construction of wind-powered generating facilities, MidAmerican Energy accrued as property, plant and equipment, net certain amounts for which it was not contractually obligated to pay until a stated future date. Refer to Note 10 for additional information.

(22) 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,		
	2014	2013	2012
Operating revenue:			
PacifiCorp	$ 5,252	$ 5,147	$ 4,882
MidAmerican Funding	3,762	3,413	3,247
NV Energy	3,241	(20)	—
Northern Powergrid	1,283	1,025	1,035
BHE Pipeline Group	1,078	952	968
BHE Transmission	62	—	—
BHE Renewables	623	355	166
HomeServices	2,144	1,809	1,312
BHE and Other[1]	(119)	(46)	(62)
Total operating revenue	$ 17,326	$ 12,635	$ 11,548
Depreciation and amortization:			
PacifiCorp	$ 745	$ 692	$ 655
MidAmerican Funding	351	403	393
NV Energy	379	—	—
Northern Powergrid	198	180	174
BHE Pipeline Group	196	190	193
BHE Transmission	13	—	—
BHE Renewables	152	71	33
HomeServices	29	33	19
BHE and Other[1]	(6)	(9)	(12)
Total depreciation and amortization	$ 2,057	$ 1,560	$ 1,455
Operating income:			
PacifiCorp	$ 1,308	$ 1,275	$ 1,034
MidAmerican Funding	423	357	369
NV Energy	791	(42)	—
Northern Powergrid	674	501	565
BHE Pipeline Group	439	446	465
BHE Transmission	16	(5)	(2)
BHE Renewables	314	223	93
HomeServices	125	129	62
BHE and Other[1]	(44)	(49)	(19)
Total operating income	4,046	2,835	2,567
Interest expense	(1,711)	(1,222)	(1,176)
Capitalized interest	89	84	54
Allowance for equity funds	98	78	74
Other, net	80	66	56
Total income before income tax expense and equity income (loss)	$ 2,602	$ 1,841	$ 1,575

	Years Ended December 31,		
	2014	2013	2012
Interest expense:			
PacifiCorp	$ 386	$ 390	$ 393
MidAmerican Funding	197	174	167
NV Energy	283	—	—
Northern Powergrid	151	141	139
BHE Pipeline Group	76	80	92
BHE Transmission	14	—	—
BHE Renewables	175	138	70
HomeServices	4	3	—
BHE and Other[1]	425	296	315
Total interest expense	$ 1,711	$ 1,222	$ 1,176
Income tax expense (benefit):			
PacifiCorp	$ 310	$ 298	$ 196
MidAmerican Funding	(110)	(110)	(108)
NV Energy	195	(15)	—
Northern Powergrid	110	23	31
BHE Pipeline Group	149	149	152
BHE Transmission	28	10	8
BHE Renewables	65	57	37
HomeServices	44	48	32
BHE and Other[1]	(202)	(330)	(200)
Total income tax expense (benefit)	$ 589	$ 130	$ 148
Capital expenditures:			
PacifiCorp	$ 1,066	$ 1,065	$ 1,346
MidAmerican Funding	1,527	1,027	645
NV Energy	558	—	—
Northern Powergrid	675	675	454
BHE Pipeline Group	257	177	152
BHE Transmission	222	—	—
BHE Renewables	2,221	1,329	770
HomeServices	17	21	8
BHE and Other	12	13	5
Total capital expenditures	$ 6,555	$ 4,307	$ 3,380

	As of December 31,		
	2014	2013	2012
Property, plant and equipment, net:			
PacifiCorp	$ 18,755	$ 18,563	$ 18,129
MidAmerican Funding	10,535	9,353	8,647
NV Energy	9,648	9,623	—
Northern Powergrid	5,599	5,476	4,923
BHE Pipeline Group	4,286	4,147	4,119
BHE Transmission	5,567	—	—
BHE Renewables	4,897	3,020	1,903
HomeServices	68	61	47
BHE and Other	(107)	(124)	(154)
Total property, plant and equipment, net	$ 59,248	$ 50,119	$ 37,614
Total assets:			
PacifiCorp	$ 23,466	$ 22,885	$ 22,973
MidAmerican Funding	15,368	13,992	13,355
NV Energy	14,454	14,233	—
Northern Powergrid	7,076	6,874	6,418
BHE Pipeline Group	4,968	4,908	4,865
BHE Transmission	7,992	465	368
BHE Renewables	6,123	3,875	3,342
HomeServices	1,629	1,381	899
BHE and Other	1,228	1,387	247
Total assets	$ 82,304	$ 70,000	$ 52,467

	Years Ended December 31,		
	2014	2013	2012
Operating revenue by country:			
United States	$ 15,857	$ 11,465	$ 10,388
United Kingdom	1,281	1,023	1,033
Canada	78	16	—
Philippines and other	110	131	127
Total operating revenue by country	$ 17,326	$ 12,635	$ 11,548
Income (loss) before income tax expense and equity income (loss) by country:			
United States	$ 2,001	$ 1,388	$ 1,060
United Kingdom	557	373	432
Canada	4	—	(4)
Philippines and other	40	80	87
Total income before income tax expense and equity income (loss) by country:	$ 2,602	$ 1,841	$ 1,575

	As of December 31,		
	2014	2013	2012
Property, plant and equipment, net by country:			
United States	$ 47,918	$ 44,460	$ 32,491
United Kingdom	5,584	5,463	4,915
Canada	5,570	3	—
Philippines and other	176	193	208
Total property, plant and equipment, net by country	$ 59,248	$ 50,119	$ 37,614

(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, 2014 and 2013 (in millions):

	PacifiCorp	MidAmerican Funding	NV Energy	Northern Powergrid	BHE Pipeline Group	BHE Transmission	BHE Renewables	Home-Services	Other	Total
December 31, 2012	$ 1,126	$ 2,102	$ —	$ 1,135	$ 179	$ —	$ 71	$ 507	$ —	$5,120
Acquisitions	—	—	2,280	—	—	—	—	188	4	2,472
Foreign currency translation	—	—	—	14	—	—	—	—	—	14
Impairment (Note 7)	—	—	—	—	—	—	(53)	—	—	(53)
Other	3	—	—	—	(26)	—	(3)	—	—	(26)
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

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, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the Chief Executive Officer (principal executive officer) and the Chief Financial Officer (principal financial officer), of the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) promulgated under the Securities and Exchange Act of 1934, as amended). Based upon that evaluation, the Company's management, including the Chief Executive Officer (principal executive officer) and the Chief Financial Officer (principal financial officer), concluded that the Company's disclosure controls and procedures were effective to ensure that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and is accumulated and communicated to management, including the Company's Chief Executive Officer (principal executive officer) and Chief Financial Officer (principal financial officer), or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

As a result of the Company's acquisition of AltaLink on December 1, 2014, the Company has expanded its internal control over financial reporting to include consolidation of the AltaLink financial statements, as well as acquisition related accounting and disclosures. There has been no other change in the Company's internal control over financial reporting during the quarter ended December 31, 2014 that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

Management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in the Securities Exchange Act of 1934 Rule 13a-15(f). Under the supervision and with the participation of the Company's management, including the Chief Executive Officer (principal executive officer) and the Chief Financial Officer (principal financial officer), the Company's management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting as of December 31, 2014 as required by the Securities Exchange Act of 1934 Rule 13a-15(c). In making this assessment, the Company's management used the criteria set forth in the framework in "Internal Control - Integrated Framework (2013)" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the evaluation conducted under the framework in "Internal Control - Integrated Framework (2013)," the Company's management concluded that the Company's internal control over financial reporting was effective as of December 31, 2014.

On December 1, 2014, the Company completed the acquisition of AltaLink In conducting its evaluation of the effectiveness of the Company's internal control over financial reporting, the Company's management elected to exclude AltaLink from this evaluation as permitted under SEC rules. AltaLink constituted 9.0% of total consolidated assets as of December 31, 2014, and 0.8% of total consolidated operating income for the year ended December 31, 2014.

Berkshire Hathaway Energy Company
February 27, 2015

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

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 February 18, 2015, with respect to the current directors and executive officers of BHE:

GREGORY E. ABEL, 52, 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 H. J. Heinz Company.

PATRICK J. GOODMAN, 48, 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 also a director of PacifiCorp and a manager of MidAmerican Funding, LLC.

DOUGLAS L. ANDERSON, 56, Executive Vice President, General Counsel and Corporate Secretary since 2012. Mr. Anderson was Senior Vice President, General Counsel and Corporate Secretary from 2001 to 2012. Mr. Anderson joined BHE in 1993. Mr. Anderson is also a director of PacifiCorp and a manager of MidAmerican Funding, LLC.

MAUREEN E. SAMMON, 51, Senior Vice President and Chief Administrative Officer since 2007. Ms. Sammon has been employed by BHE and its predecessor companies since 1986 and has held several positions, including Vice President, Human Resources and Insurance.

WARREN E. BUFFETT, 84, 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 H. J. Heinz Company. 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., 83, Director. Mr. Scott has been a director of BHE since 1991 and has been Chairman of the Board of Directors of Level 3 Communications, Inc., a successor to certain businesses of Peter Kiewit Sons' Inc., for more than five years. Mr. Scott is also a director of Peter Kiewit Sons' Inc., Berkshire Hathaway and Valmont Industries, Inc. 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, 65, 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 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.

Item 11. Executive Compensation

Compensation Discussion and Analysis

Compensation Philosophy and Overall Objectives

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

How is Compensation Determined

Our Compensation Committee is comprised of Messrs. Warren E. Buffett and Walter Scott, Jr. The Compensation Committee is responsible for the establishment and oversight of our compensation policy. Approval of compensation decisions for our 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.

Our criteria for assessing executive performance and determining compensation in any year is inherently subjective and is not based upon specific formulas or weighting of factors. We do not specifically use other companies as benchmarks when establishing our NEOs' compensation. 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 2014 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.

We engage the compensation practice of Towers Watson & Co., or 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 Towers Watson for this service was $7,387 in 2014. We also engage Towers Watson to provide other services unrelated to executive compensation, including actuarial, administration and consulting services related to our retirement plans. These services are approved by senior management and the aggregate fees paid to Towers Watson for these services were $2,805,778 in 2014. Our Board of Directors is not involved in the selection or approval of Towers Watson for these services.

Discussion and Analysis of Specific Compensation Elements

Base Salary

We determine base salaries for all of our NEOs by reviewing our overall performance and each NEO's performance, the value each NEO brings to us and general labor market conditions. While base salary provides a base level of compensation intended to be competitive with the external market, the annual base salary adjustment for each NEO 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. In 2014, base salaries for all NEOs increased on average by 4.65% effective January 1, 2014. There were no other base salary changes for our NEOs during the year after the January 1, 2014 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 our 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, our 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 2014. 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 our 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, we may grant cash performance awards periodically during the year to one or more NEOs to reward the accomplishment of significant non-recurring tasks or projects. These awards are discretionary and are approved by the Chairman and CEO, as delegated by the Compensation Committee. In December 2014, awards were granted to Messrs. Goodman and Anderson in recognition of their efforts related to certain acquisition 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. Our current long-term incentive compensation program is cash-based. We have 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 our interests and the interests of the participating employees. Messrs. Goodman and Anderson and Ms. Sammon participate in this plan, while our Chairman and CEO does not. Our 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 designates 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 five-year period starting in the performance year. Participants allocate the value of their deferral accounts among various investment alternatives. Gains or losses may be incurred based on investment performance. Participating NEOs may elect to defer all or a part of the award or receive payment in cash after the five-year mandatory deferral and vesting period. Vested balances (including any investment gains or losses thereon) of terminating participants are paid at the time of termination.

Incremental Profit Sharing Plan

The Incremental Profit Sharing Plan, or IPSP, is designed to align our interests and the interests of the Chairman and CEO. The IPSP provides for a cash award based upon our 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 our EPS is greater than $26.86 per share, but less than or equal to $28.65 per share, $25 million if our EPS is greater than $28.65 per share, but less than $30.55 per share, or $40 million if our EPS is greater than $30.55 per share. Mr. Abel earned $12 million under the IPSP through December 31, 2014. Messrs. Goodman and Anderson and Ms. 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. We include 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 we have 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 MidAmerican Energy Holdings Company Executive Voluntary Deferred Compensation Plan, or DCP, provides a means for all NEOs to make voluntary deferrals of up to 50% of base salary and 100% of short-term incentive compensation awards. We include the DCP as part of the participating NEO's overall compensation in order to provide a comprehensive, competitive package. The deferrals and any investment returns grow on a tax-deferred basis. Amounts deferred under the DCP receive a rate of return based on the returns of any combination of various investment options offered under the DCP and selected by the participant. The plan allows participants to choose from three forms of distribution. The plan permits us to make discretionary contributions on behalf of participants; however, we have not made contributions to date.

Financial Planning and Tax Preparation

We reimburse 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 our NEOs best utilize the other forms of compensation we provide to them.

Executive Life Insurance

We provide 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. We include 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. We believe these post-termination payments are an important component of the competitive compensation package we offer 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 our 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	2014	$ 1,000,000	$ 11,500,000	$ 12,000,000	$ 2,625,000	$ 450,612	27,575,612
and Chief Executive Officer	2013	1,000,000	9,500,000	—	—	169,770	10,669,770
	2012	1,000,000	9,500,000	—	2,069,000	236,392	12,805,392
Patrick J. Goodman, Executive Vice	2014	450,000	1,717,600	—	1,146,000	46,413	3,360,013
President and Chief Financial	2013	410,000	1,756,630	—	—	58,502	2,225,132
Officer	2012	367,500	1,707,058	—	818,000	58,045	2,950,603
Douglas L. Anderson, Executive Vice	2014	339,000	1,228,551	—	8,000	30,704	1,606,255
President, General Counsel and	2013	330,000	1,140,973	—	1,000	30,090	1,502,063
Corporate Secretary	2012	315,000	1,121,531	—	—	30,149	1,466,680
Maureen E. Sammon, Senior Vice	2014	260,000	686,122	—	9,000	30,140	985,262
President and Chief	2013	245,000	666,795	—	1,000	29,450	942,245
Administrative Officer	2012	230,000	667,956	—	—	28,450	926,406

(1) Consists of annual cash incentive awards earned pursuant to the PIP for our NEOs, performance awards earned related to non-routine projects, and the vesting of LTIP awards and associated vested earnings. The breakout for 2014 is as follows:

			LTIP		
	PIP	Performance Award	Vested Awards	Vested Earnings	Total
Gregory E. Abel	$ 11,500,000	$ —	$ —	$ —	$ —
Patrick J. Goodman	500,000	200,000	790,000	227,600	1,017,600
Douglas L. Anderson	350,000	175,000	509,500	194,051	703,551
Maureen E. Sammon	250,000	—	316,457	119,665	436,122

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 2014, the gross award was determined based on the overall achievement of our 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 our cash balance and SERP, as applicable. Amounts are computed using assumptions consistent with those used in preparing the related pension disclosures in our Notes to Consolidated Financial Statements in Item 8 of this Form 10-K and are as of December 31, 2014. No participant in our DCP earned "above-market" or "preferential" earnings on amounts deferred.

(3) Amounts consist of 401(k) contributions we 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 we paid on behalf of Messrs. Abel, Goodman and Anderson. The personal use of corporate aircraft represents our incremental cost of providing this personal benefit determined by applying the percentage of flight hours used for personal use to our incremental expenses incurred from operating our corporate aircraft, partially offset by reimbursed costs by the NEO. All other compensation is based upon amounts paid by us.

Items required to be reported and quantified are as follows: Mr. Abel - personal use of corporate aircraft of $425,302 and 401(k) contributions of $12,740; Mr. Goodman - 401(k) contributions of $29,640; Mr. Anderson - 401(k) contributions of $29,640; and Ms. Sammon - 401(k) contributions of $29,640.

(4) Any amounts voluntarily deferred by the NEO, if applicable, are included in the appropriate column in the summary compensation table.

Pension Benefits

The following table sets forth certain information regarding the defined benefit pension plan accounts held by each of our NEOs as of December 31, 2014:

Name	Plan name	Number of years credited service(1)	Present value of accumulated benefit(2)	Payments during last fiscal year
Gregory E. Abel	SERP	n/a	$ 11,084,000	$ —
	MidAmerican Energy Company Retirement Plan	16 years	309,000	—
Patrick J. Goodman	SERP	20 years	3,338,000	—
	MidAmerican Energy Company Retirement Plan	10 years	212,000	—
Douglas L. Anderson	MidAmerican Energy Company Retirement Plan	10 years	222,000	—
Maureen E. Sammon	MidAmerican Energy Company Retirement Plan	22 years	247,000	—

(1) Mr. Goodman's credited years of service, for purposes of the SERP only, includes 16 years of service with us 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 our Notes to Consolidated Financial Statements in Item 8 of this Form 10-K and are as of December 31, 2014, which is the measurement date for the plans. The 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 0.83% in 2015 and 2016 and 3.00% thereafter; a cash balance conversion rate of 4.00% in 2014 and thereafter; a discount rate of 4.00%; an expected retirement age of 65; postretirement 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 cash balance conversion mortality using the Notice 2013-49 tables.

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, we maintain 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 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.

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

Nonqualified Deferred Compensation

The following table sets forth certain information regarding the nonqualified deferred compensation plan accounts held by each of our NEOs as of December 31, 2014:

Name	Executive contributions in 2014[1]	Registrant contributions in 2014	Aggregate earnings in 2014	Aggregate withdrawals/ distributions	Aggregate balance as of December 31, 2014[2][3]
Gregory E. Abel	$ —	$ —	$ 222,816	$ (261,661)	$ 2,910,747
Patrick J. Goodman	—	—	69,658	—	1,495,856
Douglas L. Anderson	676,238	—	412,542	(81,234)	5,004,073
Maureen E. Sammon	397,792	—	190,280	—	3,202,650

(1) The contribution amount shown for Mr. Anderson and Ms. Sammon includes $278,980 and $257,325, respectively, earned from their 2010 LTIP award prior to 2014. Therefore, that amount is not included in the 2014 total compensation reported for them in the Summary Compensation Table.

(2) The aggregate balance as of December 31, 2014 shown for Mr. Anderson and Ms. Sammon includes $414,975 and $212,492, respectively, of compensation previously reported in 2013 in the Summary Compensation Table and $225,498 and $288,296, respectively, of compensation previously reported in 2012 in the Summary Compensation Table.

(3) Excludes the value of 10,041 shares of our 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 our DCP is restricted to select management and highly compensated employees. The plan provides tax benefits to eligible participants by allowing them to defer compensation on a pretax basis, thus reducing their current taxable income. Deferrals and any investment returns grow on a tax-deferred basis, thus participants pay no income tax until they receive distributions. The DCP permits participants to make a voluntary deferral of up to 50% of base salary and 100% of short-term incentive compensation awards. All deferrals are net of social security taxes. Amounts deferred under the DCP receive a rate of return based on the returns of any combination of various investment alternatives offered by the plan and selected by the participant. Gains or losses are calculated daily, and returns are posted to accounts based on participants' fund allocation elections. Participants can change their fund allocations as of the end of any day on which the market is open.

The DCP allows participants to maintain three accounts based upon when they want to receive payments: retirement account, in-service account and education account. Both the retirement and in-service accounts can be distributed as lump sums or in up to 10 annual installments. The education account is distributed in four annual installments. If a participant leaves employment prior to retirement (age 55) all amounts in the participant's account will be paid out in a lump sum as soon as administratively practicable. Participants are 100% vested in their deferrals and any investment gains or losses recorded in their accounts.

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

Potential Payments Upon Termination

We have 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 us 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 Ms. 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 our 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 we terminate 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, we 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, 2019, 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, 2015, for the agreement not to extend to August 6, 2020).

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, 2014, 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	$ —	$ —	$ —	$ 9,750,000	$ —	$ —
Involuntary Without Cause, Disability and Voluntary With Good Reason	23,000,000	—	—	9,750,000	85,699	—
Death	23,000,000	—	1,865,771	9,750,000	82,791	—

(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 us.

(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 we currently charge 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 our 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. We 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, we 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, we 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, we do 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 we terminate 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, we 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, 2016, 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, 2014, 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	$ —	$ —	$ —	$ 1,747,000	$ —	$ —
Involuntary With Cause	—	—	—	—	—	—
Involuntary Without Cause and Voluntary With Good Reason	4,051,000	—	—	1,747,000	24,528	—
Death	4,051,000	1,825,441	863,827	3,465,000	24,528	—
Disability	4,051,000	1,825,441	—	3,642,000	24,528	—

(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 us.

(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 we currently charge 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 our 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. We 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, we 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, we do not believe that any of the termination scenarios are subject to any excise tax.

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, 2014, 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	$ —	$ —	$ —	$ 28,000	$ —	$ —
Death and Disability	—	1,464,340	—	28,000	—	—

(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, 2014, 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	$ —	$ —	$ —	$ 45,000	$ —	$ —
Death and Disability	—	841,280	—	45,000	—	—

(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

Our 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, our majority owner. Mr. Scott is a former officer of ours. Based on the standards of the New York Stock Exchange LLC, on which the common stock of our majority owner, Berkshire Hathaway, is listed, our Board of Directors has determined that Messrs. Buffett and Scott are not independent because of their ownership of our common stock. None of our executive officers serves as a member of the compensation committee of any company that has an executive officer serving as a member of our Board of Directors. None of our executive officers serves as a member of the board of directors of any company that has an executive officer serving as a member of our Compensation Committee. See also Item 13 of this Form 10-K.

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

Beneficial Ownership

We are a consolidated subsidiary of Berkshire Hathaway. The balance of our 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 our shares of common stock held by each of our directors, executive officers and all of our directors and executive officers as a group as of February 18, 2015:

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%
Douglas L. Anderson	—	—
Warren E. Buffett(3)(5)	—	—
Patrick J. Goodman	—	—
Marc D. Hamburg(3)(5)	—	—
Maureen E. Sammon	—	—
All directors and executive officers as a group (7 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 our directors, executive officers and all of our directors and executive officers as a group as of February 18, 2015:

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	2,289	*
Douglas L. Anderson		
Class A	4	*
Class B	300	*
Warren E. Buffett[5]		
Class A	336,000	40.7%
Class B	1,469,357	*
Patrick J. Goodman		
Class A	5	*
Class B	796	*
Marc D. Hamburg[5]		
Class A	—	—
Class B	—	—
Maureen E. Sammon		
Class A	—	—
Class B	4,416	*
All directors and executive officers as a group (7 persons)		
Class A	336,114	40.7%
Class B	1,477,158	*

* Less than 1%

(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 our common stock and the closing price of Berkshire Hathaway common stock on February 18, 2015, Mr. Scott and the Scott Family Interests and Mr. Abel would be entitled to exchange their shares of our common stock for either 15,026 and 1,580, respectively, shares of Berkshire Hathaway Class A stock or 22,518,399 and 2,367,367, 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 1.8% of the outstanding shares of Berkshire Hathaway Class A stock or 1.8% 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 our 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 our common stock divided by the closing price of the Berkshire Hathaway common stock on the day prior to the date of exchange.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Certain Relationships and Related Transactions

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

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

As of December 31, 2014 and 2013, certain Berkshire Hathaway subsidiaries held variable-rate junior subordinated debentures due from BHE totaling $3.8 billion and $2.6 billion, respectively. Principal repayments on these securities totaled $300 million and $- million during 2014 and 2013, respectively, and interest expense on these securities totaled $78 million and $3 million during 2014 and 2013, respectively.

Director Independence

Based on the standards of the New York Stock Exchange LLC, on which the common stock of our majority owner, Berkshire Hathaway, is listed, our Board of Directors has determined that none of our directors are considered independent because of their employment by Berkshire Hathaway or us or their ownership of our common stock.

Item 14. Principal Accountant Fees and Services

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

	2014	2013
Audit fees(1)	$ 9.0	$ 6.8
Audit-related fees(2)	0.8	0.8
Tax fees(3)	0.2	0.2
Total	$ 10.0	$ 7.8

(1) Audit fees include fees for the audit of the Company's consolidated financial statements and interim reviews of the Company's quarterly financial statements, 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.

(2) Audit-related fees primarily include fees for assurance and related services for any other statutory or regulatory requirements, audits of certain subsidiary 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 Company 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 Company. 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 BHE's independent auditor and its 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. The 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

Consolidated Financial Statements are included in Item 8. 97

(ii) Financial Statement Schedules

See Schedule I. 181
See Schedule II. 186

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

The exhibits listed on the accompanying Exhibit Index are filed as part of this Annual Report. 189

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

Not applicable.

Berkshire Hathaway Energy Company
Parent Company Only
Condensed Balance Sheets
As of December 31,
(Amounts in millions)

	2014	2013
ASSETS		
Current assets:		
Cash and cash equivalents	$ 3	$ 292
Accounts receivable	22	—
Income tax receivable	152	2
Other current assets	1	7
Total current assets	178	301
Investments in subsidiaries	31,968	27,165
Other investments	1,038	1,247
Goodwill	1,221	1,221
Other assets	1,226	980
Total assets	$ 35,631	$ 30,914
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable and other current liabilities	$ 308	$ 316
Short-term debt	395	—
Current portion of senior debt	—	250
Total current liabilities	703	566
BHE senior debt	7,860	6,366
BHE junior subordinated debentures	3,794	2,594
Notes payable - affiliate	1,981	2,010
Other long-term liabilities	839	657
Total liabilities	15,177	12,193
Equity:		
BHE shareholders' equity:		
Common stock - 115 shares authorized, no par value, 77 shares issued and outstanding	—	—
Additional paid-in capital	6,423	6,390
Retained earnings	14,513	12,418
Accumulated other comprehensive loss, net	(494)	(97)
Total BHE shareholders' equity	20,442	18,711
Noncontrolling interest	12	10
Total equity	20,454	18,721
Total liabilities and equity	$ 35,631	$ 30,914

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)

	2014	2013	2012
Operating costs and expenses:			
General and administration	$ 51	$ 64	$ 31
Depreciation and amortization	3	1	1
Total operating costs and expenses	54	65	32
Operating loss	(54)	(65)	(32)
Other income (expense):			
Interest expense	(476)	(347)	(362)
Other, net	4	25	10
Total other income (expense)	(472)	(322)	(352)
Loss before income tax benefit and equity income	(526)	(387)	(384)
Income tax benefit	(221)	(345)	(201)
Equity income	2,402	1,679	1,656
Net income	2,097	1,637	1,473
Net income attributable to noncontrolling interest	2	1	1
Net income attributable to BHE shareholders	$ 2,095	$ 1,636	$ 1,472

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)

	2014	2013	2012
Net income	$ 2,097	$ 1,637	$ 1,473
Other comprehensive (loss) income, net of tax	(397)	366	178
Comprehensive income	1,700	2,003	1,651
Comprehensive income attributable to noncontrolling interests	2	1	1
Comprehensive income attributable to BHE shareholders	$ 1,698	$ 2,002	$ 1,650

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)

	2014	2013	2012
Cash flows from operating activities	$ 1,937	$ 2,295	$ 1,019
Cash flows from investing activities:			
Investments in subsidiaries	(4,937)	(6,522)	(1,164)
Purchases of available-for-sale securities	(56)	(106)	(46)
Proceeds from sale of available-for-sale securities	35	89	42
Notes receivable from affiliate, net	(55)	(37)	(15)
Other, net	(7)	(16)	(8)
Net cash flows from investing activities	(5,020)	(6,592)	(1,191)
Cash flows from financing activities:			
Proceeds from BHE senior debt	1,493	1,994	—
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)	—	(750)
Repayments of BHE subordinated debt	(300)	—	(22)
Net proceeds from (repayments of) short-term debt	395	(825)	717
Notes payable to affiliate, net	(30)	(173)	220
Other, net	(14)	(14)	7
Net cash flows from financing activities	2,794	4,576	172
Net change in cash and cash equivalents	(289)	279	—
Cash and cash equivalents at beginning of year	292	13	13
Cash and cash equivalents at end of year	$ 3	$ 292	$ 13

The accompanying notes are an integral part of this financial statement schedule.

BERKSHIRE HATHAWAY ENERGY COMPANY
NOTES TO CONDENSED FINANCIAL STATEMENTS

Incorporated by reference are Berkshire Hathaway Energy Company ("BHE") and Subsidiaries Consolidated Statements of Changes in Equity and Consolidated Statements of Comprehensive Income for the three years ended December 31, 2014 in Part II, Item 8.

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, 2014 and 2013, the fair value of BHE's investment in BYD common stock was $881 million and $1.1 billion, respectively, which resulted in a unrealized gain of $649 million and $871 million as of December 31, 2014 and 2013, respectively.

Dividends and distributions from subsidiaries - Cash dividends paid to BHE by its subsidiaries for the years ended December 31, 2014, 2013 and 2012 were $2.3 billion, $2.5 billion and $1.1 billion, respectively. In January and February 2015, BHE received cash dividends from its subsidiaries totaling $58 million.

Guarantees

BHE has issued a limited guarantee of a specified portion of the final scheduled principal payment on December 15, 2019 on the Cordova Funding Corporation senior secured bonds in an amount up to a maximum of $37 million.

See the notes to the consolidated BHE financial statements in Part II, Item 8 for other disclosures.

Schedule II

BERKSHIRE HATHAWAY ENERGY COMPANY
CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
FOR THE THREE YEARS ENDED DECEMBER 31, 2014
(Amounts in millions)

Column A	Column B	Column C		Column D	Column E
Description	**Balance at Beginning of Year**	**Charged to Income**	**Acquisition Reserves[1]**	**Deductions**	**Balance at End of Year**
Reserves Deducted From Assets To Which They Apply:					
Reserve for uncollectible accounts receivable:					
Year ended 2014	$ 33	$ 37	$ —	$ (33)	$ 37
Year ended 2013	22	23	9	(21)	33
Year ended 2012	21	22	—	(21)	22
Reserves Not Deducted From Assets[2]:					
Year ended 2014	$ 9	$ 12	$ —	$ (10)	$ 11
Year ended 2013	9	6	—	(6)	9
Year ended 2012	8	6	—	(5)	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.

SIGNATURES

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

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 27, 2015
/s/ Patrick J. Goodman* Patrick J. Goodman	Executive Vice President and Chief Financial Officer (principal financial and accounting officer)	February 27, 2015
/s/ Walter Scott, Jr.* Walter Scott, Jr.	Director	February 27, 2015
/s/ Marc D. Hamburg* Marc D. Hamburg	Director	February 27, 2015
/s/ Warren E. Buffett* Warren E. Buffett	Director	February 27, 2015
*By: /s/ Douglas L. Anderson Douglas L. Anderson	Attorney-in-Fact	February 27, 2015

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 Berkshire Hathaway Energy Company's last fiscal year or proxy material has been sent to security holders.

EXHIBIT INDEX

Exhibit No.	Description
2.1	Share Purchase Agreement, dated as of May 1, 2014, by and among Berkshire Hathaway Energy Company and SNC-Lavalin Group Inc. and certain of its subsidiaries (incorporated by reference to Exhibit 2.1 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2014).
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 MidAmerican Energy Holdings 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	Indenture, dated as of October 4, 2002, by and between MidAmerican Energy Holdings Company and The Bank of New York, Trustee, relating to the 5.875% Senior Notes due 2012 (incorporated by reference to Exhibit 4.1 to the Berkshire Hathaway Energy Company Registration Statement No. 333-101699 dated December 6, 2002).
4.2	Second Supplemental Indenture, dated as of May 16, 2003, by and between MidAmerican Energy Holdings Company and The Bank of New York, Trustee, relating to the 3.50% Senior Notes due 2008 (incorporated by reference to Exhibit 4.3 to the Berkshire Hathaway Energy Company Registration Statement No. 333-105690 dated May 23, 2003).
4.3	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).
4.4	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).
4.5	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).
4.6	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).
4.7	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).
4.8	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).
4.9	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).

Exhibit No.	Description
4.10	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).
4.11	Indenture, dated as of March 12, 2002, by and between MidAmerican Energy Holdings Company and the Bank of New York, Trustee (incorporated by reference to Exhibit 4.11 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2001).
4.12	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 $700 million Senior Notes and Bonds (incorporated by reference to Exhibits 4.1 and 4.2 to the MidAmerican Funding, LLC Registration Statement on Form S-4, Registration No. 333-905333).
4.13	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).
4.14	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, Commission File No. 333-15387).
4.15	Third Supplemental Indenture, dated as of October 1, 2004, 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 Annual Report on Form 10-K for the year ended December 31, 2004, Commission File No. 333-15387).
4.16	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).
4.17	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).
4.18	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).
4.19	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 MidAmerican Energy Company's 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).
4.20	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 MidAmerican Energy Company's 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).
4.21	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).
4.22	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).
4.23	Trust Indenture, dated as of August 13, 2001, among Kern River Funding Corporation, Kern River Gas Transmission Company and JP Morgan Chase Bank, Trustee, relating to the $510,000,000 in principal amount of the 6.676% Senior Notes due 2016 (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).

Exhibit No.	Description
4.24	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).
4.25	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).
4.26	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).
4.27	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).
4.28	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).
4.29	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).
4.30	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).
4.31	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).
4.32	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).
4.33	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).
4.34	Indenture, dated as of February 1, 2000, among Yorkshire Power Finance 2 Limited, Yorkshire Power Group Limited and The Bank of New York, Trustee (incorporated by reference to Exhibit 10.78 to the Berkshire Hathaway Energy Company Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
4.35	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).
4.36	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).

Exhibit No.	Description
4.37	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).
4.38	Fiscal Agency Agreement, dated April 14, 2005, by and between Northern Natural Gas Company and J.P. Morgan Trust Company, National Association, Fiscal Agent, relating to the $100,000,000 in principal amount of the 5.125% Senior Notes due 2015 (incorporated by reference to Exhibit 99.1 to the Berkshire Hathaway Energy Company Current Report on Form 8-K dated April 18, 2005).
4.39	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).
4.40	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).
4.41	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).
4.42	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).
4.43	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).
4.44	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).
4.45	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).
4.46	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).
4.47	Fiscal Agency Agreement, dated February 12, 2007, by and between Northern Natural Gas Company and 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).
4.48	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).
4.49	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 (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).
4.50	Second Supplemental Indenture, dated June 29, 2007, 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 Current Report on Form 8-K dated June 29, 2007).
4.51	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 5.3% Notes due 2018 (incorporated by reference to Exhibit 4.1 to MidAmerican Energy Company Current Report on Form 8-K dated March 25, 2008).

Exhibit No.	Description
4.52	£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).
4.53	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).
4.54	£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).
4.55	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).
4.56	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 amounts 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).
4.57	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 amounts 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).
4.58	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 amounts 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).
4.59	Trust Deed, dated as of July 5, 2012, among Northern Powergrid (Yorkshire) plc and HSBC Corporate Trustee Company (UK) Limited, relating to £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).
4.60	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).
4.61	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).
4.62	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).

Exhibit No.	Description
4.63	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 PacifiCorp's Form 8-B, File No. 1-5152, as supplemented and modified by 27 Supplemental Indentures, each incorporated by reference, as follows:

Exhibit Number	PacifiCorp File Type	File Date	File Number
(4)(b)	SE	November 2, 1989	33-31861
(4)(a)	8-K	January 9, 1990	1-5152
4(a)	8-K	September 11, 1991	1-5152
4(a)	8-K	January 7, 1992	1-5152
4(a)	10-Q	Quarter ended March 31, 1992	1-5152
4(a)	10-Q	Quarter ended September 30, 1992	1-5152
4(a)	8-K	April 1, 1993	1-5152
4(a)	10-Q	Quarter ended September 30, 1993	1-5152
(4)b	10-Q	Quarter ended June 30, 1994	1-5152
(4)b	10-K	Year ended December 31, 1994	1-5152
(4)b	10-K	Year ended December 31, 1995	1-5152
(4)b	10-K	Year ended December 31, 1996	1-5152
(4)b	10-K	Year ended December 31, 1998	1-5152
99(a)	8-K	November 21, 2001	1-5152
4.1	10-Q	Quarter ended June 30, 2003	1-5152
99	8-K	September 8, 2003	1-5152
4.2	8-K	August 24, 2004	1-5152
4	8-K	June 13, 2005	1-5152
4.1	8-K	August 14, 2006	1-5152
4.1	8-K	March 14, 2007	1-5152
4.1	8-K	October 3, 2007	1-5152
4.1	8-K	July 17, 2008	1-5152
4.1	8-K	January 8, 2009	1-5152
4.1	8-K	May 12, 2001	1-5152
4.1	8-K	January 6, 2012	1-5152
4.1	8-K	June 6, 2013	1-5152
4.1	8-K	March 13, 2014	1-5152

Exhibit No.	Description
4.64	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).
4.65	Agreement of Resignation, Appointment and Acceptance, dated November 6, 2009, by and among NV Energy, Inc., The Bank of New York Mellon and The Bank of New York Trust Company, N.A. (incorporated by reference to Exhibit 4.1 to the NV Energy, Inc. Form 10-K for the year ended December 31, 2009).
4.66	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).
4.67	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).

Exhibit No.	Description
4.68	Agreement of Resignation, Appointment and Acceptance, dated November 6, 2009, by and among Nevada Power Company d/b/a NV Energy, The Bank of New York Mellon and The Bank of New York Trust Company, N.A. (incorporated by reference to Exhibit 4.2 to the Nevada Power Company Annual Report on Form 10-K for the year ended December 31, 2009).
4.69	Officer's Certificate establishing the terms of Nevada Power Company's 5 7/8% General and Refunding Mortgage Notes, Series L, due 2015 (incorporated by reference to Exhibit 4(A) to the Nevada Power Company Annual Report on Form 10-K for the year ended December 31, 2004).
4.70	Form of Nevada Power Company's 5 7/8% General and Refunding Mortgage Notes, Series L, due 2015 (incorporated by reference to Exhibit 4(B) to the Nevada Power Company Annual Report on Form 10-K for the year ended December 31, 2004).
4.71	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).
4.72	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-K for the year ended December 31, 2005).
4.73	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).
4.74	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).
4.75	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).
4.76	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).
4.77	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).
4.78	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).
4.79	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).
4.80	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).
4.81	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).
4.82	Agreement of Resignation, Appointment and Acceptance, dated November 6, 2009, by and among Sierra Pacific Power Company d/b/a NV Energy, The Bank of New York Mellon and The Bank of New York Trust Company, N.A. (incorporated by reference to Exhibit 4.3 to the Sierra Pacific Power Company Annual Report on Form 10-K for the year ended December 31, 2009).
4.83	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).

Exhibit No.	Description
4.84	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).
4.85	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).
4.86	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).
4.87	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).
4.88	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).
4.89	Second Supplemental Indenture, dated as of March 6, 2000, by and between CE Generation, LLC and Chase Manhattan Bank and trust Company, National Association.
4.90	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).
4.91	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).
4.92	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).
4.93	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).
4.94	Master Trust Indenture, dated November 21, 2005, by and between AltaLink Investments, L.P., AltaLink Investment Management Ltd. and BNY Trust Company of Canada.
4.95	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.
4.96	Third Supplemental Indenture, dated December 15, 2010, by and between AltaLink Investments, L.P., AltaLink Investment Management Ltd. and BNY Trust Company of Canada.
4.97	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.
4.98	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.
4.99	Amended and Restated Master Trust Indenture, dated April 28, 2003, by and between AltaLink, L.P., AltaLink Management Ltd. and BMO Trust Company.
4.100	Seventh Supplemental Indenture, dated April 28, 2003, by and between AltaLink, L.P., AltaLink Management Ltd. and BMO Trust Company.
4.101	Ninth Supplemental Indenture, dated May 9, 2006, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada.
4.102	Tenth Supplemental Indenture, dated May 21, 2008, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada.
4.103	Twelfth Supplemental Indenture, dated August 18, 2010, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada.

Exhibit No.	Description
4.104	Sixteenth Supplemental Indenture, dated November 15, 2012, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada.
4.105	Seventeenth Supplemental Indenture, dated May 22, 2013, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada.
4.106	Eighteenth Supplemental Indenture, dated October 24, 2014, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada.
4.107	Nineteenth Supplemental Indenture, dated October 24, 2014, by and between AltaLink, L.P., AltaLink Management Ltd. and BNY Trust Company of Canada.
10.1	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).
10.2	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).
10.3	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).
10.4	Amended and Restated Casecnan Project Agreement, dated June 26, 1995, between the National Irrigation Administration and CE Casecnan Water and Energy Company Inc. (incorporated by reference to Exhibit 10.1 to the CE Casecnan Water and Energy Company, Inc. Registration Statement on Form S-4 dated January 25, 1996).
10.5	Supplemental Agreement, dated as of September 29, 2003, by and between CE Casecnan Water and Energy Company, Inc. and the Philippines National Irrigation Administration (incorporated by reference to Exhibit 98.1 to the MidAmerican Energy Holdings Company Current Report on Form 8-K dated October 15, 2003).
10.6	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).
10.7	MidAmerican Energy Holdings 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).
10.8	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).
10.9	Berkshire Hathaway Energy Company Long-Term Incentive Partnership Plan as Amended and Restated January 1, 2014.
10.10	Summary of Key Terms of Compensation Arrangements with Berkshire Hathaway Energy Company Named Executive Officers and Directors.
10.11	$600,000,000 Credit Agreement, dated as of June 28, 2012, among MidAmerican Energy Holdings 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).
10.12	$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).

Exhibit No.	Description
10.13	$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).
10.14	$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).
10.15	£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).
10.16	Equity Contribution Agreement, dated as of February 24, 2012, by and among MidAmerican Energy Holdings Company, as the Contributor, Topaz Solar Farms LLC, as the Company, and The Bank of New York Mellon Trust Company, N.A., as the Collateral Agent (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, 2012).
10.17	Equity Contribution Agreement (Financing Documents), dated as of June 27, 2013, among MidAmerican Energy Holdings Company, as the Contributor, Solar Star Funding, LLC, as the Company, SSC XIX, LLC, as the SS1 Company Owner, SSC XX, LLC, as the SS2 Company Owner, Solar Star California XIX, LLC and Solar Star California XX, LLC, as the Project Companies, and Wells Fargo Bank, National Association, as the Collateral Agent (incorporated by reference to Exhibit 10.17 to the Berkshire Hathaway Energy Company Registration Statement No. 333-193339).
10.18	$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).
10.19	$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).
10.20	$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).
10.21	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.
10.22	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.
10.23	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.
10.24	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.
10.25	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.

Exhibit No.	Description
10.26	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.
10.27	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.
10.28	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.
10.29	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.
10.30	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.
10.31	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.
10.32	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.
10.33	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.
14.1	MidAmerican Energy Holdings Company Code of Ethics For Chief Executive Officer, Chief Financial Officer and Other Covered Officers (incorporated by reference to Exhibit 14.1 to the Berkshire Hathaway Energy Company Annual Report on Form 10-K for the year ended December 31, 2013).
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.
95	Coal Mine Safety Disclosures Required by the Dodd-Frank Wall Street Reform and Consumer Protection Act.
101	The following financial information from Berkshire Hathaway Energy Company's Annual Report on Form 10-K for the year ended December 31, 2014 is formatted in XBRL (eXtensible Business Reporting Language) and included herein: (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Operations, (iii) the Consolidated Statements of Comprehensive Income, (iv) the Consolidated Statements of Changes in Equity, (v) the Consolidated Statements of Cash Flows and (vi) the Notes to Consolidated Financial Statements, tagged in summary and detail.

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 27, 2015, 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, 2014.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
February 27, 2015

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, 2014 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 27, 2015

/s/ Gregory E. Abel
GREGORY E. ABEL

/s/ Warren E. Buffett
WARREN E. BUFFETT

/s/ Walter Scott, Jr.
WALTER SCOTT, JR.

/s/ Patrick J. Goodman
PATRICK J. GOODMAN

/s/ Marc D. Hamburg
MARC D. HAMBURG

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 27, 2015

/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 27, 2015

/s/ Patrick J. Goodman
Patrick J. Goodman
Executive Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 32.1

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

I, Gregory E. Abel, Chairman, 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, 2014 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

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

Date: February 27, 2015

/s/ Gregory E. Abel
Gregory E. Abel
Chairman, 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, 2014 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

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

Date: February 27, 2015

/s/ Patrick J. Goodman
Patrick J. Goodman
Executive Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 95

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

PacifiCorp and its subsidiaries operate certain coal mines and coal processing facilities (collectively, the "mining facilities") that are regulated by the Federal Mine Safety and Health Administration ("MSHA") under the Federal Mine Safety and Health Act of 1977 (the "Mine Safety Act"). MSHA inspects PacifiCorp's mining facilities on a regular basis. The total number of reportable Mine Safety Act citations, orders, assessments and legal actions for the year ended December 31, 2014 are summarized in the table below and are subject to contest and appeal. The severity and assessment of penalties may be reduced or, in some cases, dismissed through the contest and appeal process. Amounts are reported regardless of whether PacifiCorp has challenged or appealed the matter. Coal reserves that are not yet mined and mines that are closed or idled are not included in the information below as no reportable events occurred at those locations during the year ended December 31, 2014. There were no mining-related fatalities during the year ended December 31, 2014. PacifiCorp has not received any notice of a pattern, or notice of the potential to have a pattern, of violations of mandatory health or safety standards that are of such nature as could have significantly and substantially contributed to the cause and effect of coal or other mine health or safety hazards under Section 104(e) of the Mine Safety Act during the year ended December 31, 2014.

	Mine Safety Act						Legal Actions		
Mining Facilities	Section 104 Significant and Substantial Citations[1]	Section 104(b) Orders[2]	Section 104(d) Citations/ Orders[3]	Section 110(b)(2) Violations[4]	Section 107(a) Imminent Danger Orders[5]	Total Value of Proposed MSHA Assessments (in thousands)	Pending as of Last Day of Period[6]	Instituted During Period	Resolved During Period
Deer Creek	12	—	—	—	—	$ 38	4	5	10
Bridger (surface)	3	—	2	—	—	8	3	3	4
Bridger (underground)	47	—	2	—	1	219	11	19	19
Cottonwood Preparatory Plant	—	—	—	—	—	—	—	—	—
Wyodak Coal Crushing Facility	—	—	—	—	—	—	—	—	—

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

(2) For alleged failure to totally abate the subject matter of a Mine Safety Act Section 104(a) citation within the period specified in the citation.

(3) For alleged unwarrantable failure (i.e., aggravated conduct constituting more than ordinary negligence) to comply with a mandatory health or safety standard.

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

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

(6) Amounts include 13 contests of proposed penalties under Subpart C, four contests of citations or orders under Subpart B and one labor-related complaint under Subpart E of the Federal Mine Safety and Health Review Commission's procedural rules. The pending legal actions are not exclusive to citations, notices, orders and penalties assessed by MSHA during the reporting period.